NUREG-1705

Safety Evaluation Report Related to the License Renewal of Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Docket Nos. 50-317 and 50-318

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Calvert Cliffs Nuclear Power Plant, Units 1 and 2 license renewal application by the U.S. Nuclear Regulatory Commission (NRC) staff. The Baltimore Gas and Electric Company requested renewal of the Class 104b operating licenses for the Calvert Cliffs units (license numbers DPR-53 and DPR-69) for a period of 20 years beyond the current expiration of midnight, July 31, 2014, for Unit 1 and midnight, August 13, 2016, for Unit 2. By letter dated April 8, 1998, the Baltimore Gas and Electric Company submitted the license renewal application for Calvert Cliffs in accordance with Part 54 of Title 10 of the Code of Federal Regulations.

The Calvert Cliffs nuclear station is located on the west shore of the Chesapeake Bay in Calvert County, Maryland, approximately 45 miles southeast of Washington, D.C., and 60 miles south of Baltimore, Maryland. Operation of the twin Combustion Engineering pressurized-water reactors results in an approximate net electrical output of 845 megawatts for each reactor.

This SER presents the results of the staff's review of information submitted in conjunction with the renewal application. In an earlier version of this safety evaluation report (SER) issued on March 21, 1999, the staff identified a number of open and confirmatory items. All of those items have been resolved, as discussed in this SER. On the basis of its evaluation of the application the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2.

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SUMMARY

This report describes the results of a review by the Nuclear Regulatory Commission (NRC) staff of an application to renew the licenses for the two units of the Calvert Cliffs nuclear power plant. Under the Atomic Energy Act, the NRC issues licenses for commercial power reactors to operate for up to 40 years. The Act also permits the licenses to be renewed. The NRC established license renewal requirements in the regulations. When those requirements are satisfied, a license can be renewed for up to 20 additional years.

Plant owners are interested in license renewal because they need to know what requirements must be satisfied to permit long-term plant operation. This knowledge helps them to predict the cost of plant operation for long-term energy planning.

The requirements for license renewal are presented in Part 54 of Title 10 to the Code of Federal Regulations (10 CFR Part 54). When those requirements were developed, the NRC concluded that the existing licensing basis and the regulatory process are adequate to maintain safe plant operation, except for the possible effects of aging on passive systems, structures and components. Therefore, the requirements in Part 54 focus on managing the effects of aging for passive structures and components, like buildings, tanks and pipes.

The NRC also established requirements for a license renewal environmental report in Part 51. Those requirements establish the scope of a review of environmental impacts, which is part of the NRC's responsibilities under the National Environmental Policy Act (NEPA). The results of that review are described in a separate NRC report.

In a letter dated April 8, 1998, the Baltimore Gas and Electric Company (BGE) filed an application to renew the licenses for their two-unit Calvert Cliffs plant. BGE requested a 20-year extension in the license term for both units. The existing licenses expire on midnight July 31, 2014 and August 13, 2016, respectively. If granted, the renewed licenses would extend to July 31, 2034 and August 13, 2036, respectively.

The Calvert Cliffs plant is located on the west shore of the Chesapeake Bay in Calvert County, Maryland. It is approximately 45 miles southeast of Washington, D.C., and 60 miles south of Baltimore, Maryland. Each unit is a Combustion Engineering pressurized water reactor that produces a net electric output of about 845 megawatts.

In accordance with Part 54, BGE submitted information in their renewal application that identifies all plant systems, structures, and components: (1) that are safety-related; (2) whose failure could affect safety-related functions; and (3) that are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout. BGE's application also describes how the effects of aging will be managed in such a way that the intended functions of those structures and components will be maintained for the 20-year period of extended operation. These structures and components include, but are not limited to, the containment building, other safety-related structures, the reactor vessel, the reactor cooling system pressure boundary,

steam generators, the pressurizer, piping, pump casings, and valve bodies. The surveillance and maintenance programs for active equipment (for example, motors, diesel generators, air compressors, control rod drives, instruments, cooling fans, and batteries), as well as other aspects of the plant design and licensing basis, are required to be maintained throughout the period of extended operation.

For some passive structures and components within the scope of the renewal evaluation, no additional action was required where BGE demonstrated that the existing programs provide adequate aging management. In other cases, BGE described changes to existing programs and new programs to ensure that applicable aging effects would be adequately managed. These activities include, for example, adding new monitoring programs, increasing inspections, or revising inspection criteria.

Another requirement for license renewal is the identification and updating of time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are made and incorporated into design calculations for several of the plant's systems, structures, and components. These calculations must be shown to be valid for the period of extended operation or be projected to the end of the period of extended operation, or the applicant must demonstrate that the effect of aging on these structures, systems, and components will be adequately managed for the period of extended operation.

This report describes the results of the NRC staff's review of the BGE programs to manage aging effects. In this report, we conclude that BGE has demonstrated that aging effects applicable to the required scope of systems, structures and components will be adequately managed for the 20-year period of extended operation. Our evaluation describes the features of the maintenance and inspection programs that we relied on to develop this conclusion. Our evaluation also describes how BGE has resolved our questions about specific aging management concerns. In some cases, our conclusion is based on changes in procedures or actions that will be taken in the future. These procedure changes and future actions are summarized in a list included as Appendix E to this report. BGE will update their final safety analysis report, associated with the existing license, to include the changes to the licensing basis reflected in the Appendix E list, which we relied on to grant a renewed license.

During meetings to gather public comments about the environmental impacts of extending the Calvert Cliffs licenses, we heard several concerns related to plant safety because of aging effects. Interested individuals and groups expressed specific concerns regarding embrittlement of the reactor vessel and other aging effects on plant safety systems and fuel storage facilities. In applicable sections of this report, we describe the particular programs, maintenance activities, and inspection procedures that we have relied on to conclude that those concerns have been adequately addressed.

The conclusions in this report have been verified by inspections conducted by the NRC. The scope of the inspections consisted of selected information in the renewal application and information in this report. The inspection results form the basis for a separate recommendation by the Administrator of the regional office responsible for the plant.

The basis for the conclusions in this report are also reviewed by the NRC's Advisory Committee on Reactor Safeguards. They independently review the application, and submit their recommendation directly to the Commission. Their recommendation is included in the published version of this report.

In our recommendation for granting a renewed license for Calvert Cliffs, we have described the programs, maintenance activities, and inspection procedures that we rely on to conclude that there is reasonable assurance that actions have been or will be taken to manage effects of aging for a 20-year period of extended operation, such that the plant can continue to operate safely.

1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2, as filed by the applicant Baltimore Gas and Electric Company (BGE or Applicant). By a letter dated April 8, 1998, BGE submitted its application to the United States Nuclear Regulatory Commission (NRC) for renewal of the Calvert Cliffs operating licenses for an additional 20 years. This report was prepared by the NRC staff and summarizes the results of the staff's safety review of the renewal application for compliance with the requirements of 10 CFR Part 54 "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC License Renewal Project Manager for Calvert Cliffs is David L. Solorio. Mr. Solorio may be contacted by calling 301-415-1973, or by writing to the License Renewal and Standardization Branch, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001.

In its April 8, 1998, submittal, BGE requested renewal of the Class 104b operating licenses for Calvert Cliffs Nuclear Power Plant, Units 1 and 2 (license numbers DPR-53 and DPR-69, respectively) for a period of 20 years beyond the current license expirations of midnight, July 31, 2014, and midnight, August 13, 2016, respectively. The nuclear station is located on the west shore of the Chesapeake Bay in Calvert County, Maryland, approximately 45 miles southeast of Washington, DC, and 60 miles south of Baltimore, Maryland. 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 (UFSAR) for Calvert Cliffs Nuclear Power Plant, Units 1 and 2.

The license renewal process proceeds along two tracks: a technical review of safety issues and an environmental review. The requirements for these reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review for the Calvert Cliffs license renewal is based on BGE's application for license renewal and on the licensee's answers to requests for additional information (RAIs) from the NRC staff. In meetings and docketed correspondence, BGE has also supplemented the answers that it has given to the RAIs. The license renewal application and all pertinent information and materials, including the UFSAR mentioned above, are available to the public for review at the NRC Public Document Room, 2120 L Street, NW., Washington, D.C. 20555-0001. In addition, the application and significant information and materials related to the renewal review are available on the NRC Web page at www.nrc.gov.

This SER summarizes the results of the staff's safety review of the Calvert Cliffs license renewal application and delineates the scope of the technical details considered in evaluating the safety aspects of its proposed operation for an additional 20 years beyond the term of the current operating license. The license renewal application was reviewed in accordance with the NRC regulations and the guidance provided in the NRC draft Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants, dated September 1997.

Chapters 2 through 4 of the SER address the staff's review and evaluation of license renewal issues that have been considered during the review of the application. Chapter 5 contains the report by the Advisory Committee on Reactor Safeguards (ACRS). The conclusions of this report are given in Chapter 6.

Appendix A is a chronology of NRC's principal correspondence related to the review of the application. Appendix B is a bibliography of the references used during the course of the review. Appendix C is a list of abbreviations used throughout the report. The NRC staff principal reviewers and its contractors for this project are listed in Appendix D.

Appendix E presents a summary listing of the programs, maintenance activities and inspection procedures that formed a significant basis for the staff's conclusion. As such, this list represents those commitments that warrant regulatory control. BGE will incorporate appropriate changes to the next update of the final safety analysis report (FSAR), following the issuance of the renewed license. The FSAR will be updated for each item in Appendix E in accordance with the guidance for 10 CFR Section 50.71(e). Since future changes to the FSAR will be made in accordance with 10 CFR Section 50.59, these programs, maintenance activities and inspection procedures will be adequately controlled. Until the FSAR update is complete, a license condition requires that any changes to the items on the list be made in accordance with Section 50.59.

The listing in Appendix E also identifies future actions. Throughout this safety evaluation report, the staff has described various schedules for future actions. The staff has determined that none of the future actions are required prior to the end of the current license term in order to effectively manage aging. Therefore, as long as they are completed by the end of the current license term, licensee can make changes to such schedules without prior NRC approval. However, all of the future actions must be completed before the plant enters the period of extended operation, except for the volumetric inspections of the control element drive mechanisms in Unit 1 which will be completed by 2029 as described in Section 3.2.3.2.1.C (6) of the SER. Accordingly, the renewed license also includes a condition that all of the future actions must be completed by the end of the existing license term.

In accordance with 10 CFR Part 51, the staff prepared draft and final plant-specific supplements to the generic environmental impact statement (GEIS) that discuss the considerations related to renewing the license for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. The draft and final plant-specific supplements to the GEIS were issued separate from this report.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, licenses for commercial power reactors to operate are issued for 40 years. These licenses can be renewed for up to 20 additional years. The original 40-year license term was selected on the basis of economic and antitrust considerations—not by technical limitations. However, some individual plant and equipment designs may have been engineered on the basis of an expected 40-year service life.

In 1982, the NRC held a workshop on nuclear power plant aging, in anticipation of the interest in license renewal. That led the NRC to establish a comprehensive program plan for nuclear plant aging research (NPAR). Based on the results of that research, a technical review group concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to life extension for nuclear power plants.

In 1991, the NRC published the license renewal rule in 10 CFR Part 54. The NRC participated in, and industry sponsored, demonstration programs to apply the rule to pilot plants and develop experience to establish implementation guidance. To establish a scope of review for license renewal, the rule defined age-related degradation unique to license renewal. However, during the demonstration program, the NRC found that many aging mechanisms occur and are managed during the period of the initial license. In addition, the NRC found that the scope of the review did not allow sufficient credit for existing programs, particularly the implementation of the maintenance rule, which also manages plant aging phenomena.

As a result, in 1995 the NRC amended the license renewal rule. The amended Part 54 established a regulatory process that is simpler, more stable, and more predictable than the previous license renewal rule. In particular, Part 54 was clarified to focus on managing the adverse effects of aging rather than on identification of all aging mechanisms. The rule changes were intended to ensure that important systems, structures, and components will continue to perform their intended function in the period of extended operation. In addition, the integrated plant assessment (IPA) process was clarified and simplified to be consistent with the revised focus on passive, long-lived structures and components.

In parallel with these efforts, the NRC pursued a separate rulemaking to similarly focus the scope of the review of environmental impacts of license renewal, under 10 CFR Part 51, which is part of the NRC's responsibilities under the National Environmental Policy Act of 1969 (NEPA).

1.2.1 Safety Reviews

License renewal requirements for power reactors are based on two key principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety, with the possible exception of the detrimental effects of aging on the functionality of certain plant systems, structures, and components in the period of extended operation and possibly a few other issues related to safety only during the period of extended operation.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles, the rule in 10 CFR 54.4, defines the scope of license renewal as those plant systems, structures, and components (a) that are safety-related; (b) whose failure could affect safety-related functions; and (c) that are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout.

Pursuant to 10 CFR 54.21(a) the applicant must review all systems, structures, and components within the scope of the rule to identify structures and components subject to an aging management review (AMR). Structures and components subject to an AMR are those that perform an intended function without a change in configuration or properties and are not subject to replacement based on qualified life or specified time period. As required by 10 CFR 54.21(a), it must be demonstrated that the effects of aging will be managed in such a way that the intended function or functions of those structures and components will be maintained for the period of extended operation. Active equipment, however, is considered to be adequately monitored and maintained by existing programs. In other words, the detrimental aging effects that may occur for active equipment are more readily detectable and will be identified and corrected by routine surveillance, performance indicators, and maintenance. The surveillance and maintenance programs for active equipment, as well as other aspects of maintaining the plant design and licensing basis, are required throughout the period of extended operation. Section 54.21(d) requires that a supplement to the FSAR contain a summary description of the programs and activities for managing the effects of aging.

Another requirement for license renewal is the identification and updating of time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are made and incorporated into design calculations for several of the plant's systems, structures, and components. Under 10 CFR 54.21(c)(1), these calculations must be shown to be valid for the period of extended operation or be projected to the end of the period of extended operation, or the applicant must demonstrate that the effect of aging on these structures, systems, and components will be adequately managed for the period of extended operation.

In 1996, the NRC developed and issued draft regulatory guide DG-1047, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This guide proposes to endorse an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," which was issued in March 1996. The NRC prepared a draft standard review plan for the safety review, which was made available in the Public Document Room in September 1997. The draft regulatory guide will be used, along with the draft standard review plan, to review applications and to assess technical issue reports involved in license renewal as submitted by industry groups. As experience is gained, NRC will improve the standard review plan and clarify regulatory guidance.

1.2.2 Environmental Reviews

The environmental protection regulations, 10 CFR Part 51, were revised in December 1996 to facilitate the environmental review for license renewal. The staff prepared a Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants, NUREG-1437, in which the staff examined the possible environmental impacts associated with renewing licenses of nuclear power plants. For certain types of environmental impacts, the GEIS establishes generic findings that are applicable to all nuclear power plants. These generic findings are identified as Category 1 issues in 10 CFR Part 51, Subpart A, Appendix B. Pursuant to 10 CFR51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in an environmental report and address only those environmental impacts that are required to be evaluated on a plant-by-plant basis.

The NRC performs plant-specific reviews of the remaining environmental impacts of license renewal (those identified as Category 2 issues in 10 CFR Part 51, Subpart A, Appendix B) as well as any new and significant information, in accordance with NEPA and the requirements of 10 CFR Part 51. A public meeting was held on July 9, 1998, near Calvert Cliffs nuclear power plant as part of the scoping process to identify environmental issues specific to the plant. The result of the environmental review is an NRC preliminary recommendation with respect to the license renewal action. This is known as a draft plant-specific supplement to the GEIS, which is published for comment and discussed at a separate public meeting. After consideration of comments on the draft, NRC prepares and publishes a final plant-specific supplement to the GEIS.

Two public scoping meetings were held on July 9, 1998 to identify environmental issues specific to the plant. On February 24, 1999, the staff issued the Draft Supplement 1 to the GEIS, regarding the results of the staff's environmental review of Calvert Cliffs. During the 75-day comment period that followed, two public meetings were held on April 6, 1999, in which the staff described the results of the NRC environmental review and answered questions related to it in order to provide members of the public with information to assist them in formulating any comments they might have regarding the review. On October 5, 1999, the staff issued the Final Supplement 1 to the GEIS on Calvert Cliffs, in which it presents its final environmental analysis that considers and weighs the environmental effects of the license renewal, the environmental impacts of alternatives to license renewal, and alternatives available for avoiding adverse environmental effects. The staff considered and addressed the comments that were received during the comment period.

Based on (1) the analysis and findings in the *Generic Environmental Impact Statement for License Renewal of Nuclear Power Plants*, NUREG-1437; (2) the Environmental Report submitted by BGE; (3) consultation with other Federal, State, and local agencies; (4) its own independent review; and (5) its consideration of public comments, the staff recommended, in Supplement 1 to NUREG-1437 that the Commission determine that the adverse environmental impacts of license renewal for Calvert Cliffs Nuclear Power Plant Units 1 and Unit 2 are not so great that preserving the option of license renewal for energy planning decisionmakers would be unreasonable.

1.3 Summary of Principal Review Matters

The requirements for the renewal of operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the Calvert Cliffs application for license renewal in accordance with Commission guidance and the requirements of 10 CFR Sections 54.19, 54.21, 54.22, 54.23, and 54.25. The standards for issuance of a renewed license are contained in 10 CFR 54.29. This SER describes the results of the staff's technical review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to provide general information. Baltimore Gas and Electric provided this general information in Attachment 1 to its April 8, 1998, submittal letter regarding the application for renewed operating licenses for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. The staff finds that Calvert Cliffs has provided the information required by 10 CFR 54.19(a) in Attachment 1 of the April 8, 1998, submittal letter.

In 10 CFR 54.19(b), the Commission requires that license renewal applications include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." BGE states the following in its renewal application regarding this issue:

> 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.

The staff notes that the current indemnity agreement for Calvert Cliffs states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the attachment to the agreement. Item 3 of the attachment to the indemnity agreement lists two license numbers. By maintaining the license numbers on issuance of the renewed license, there is no need to make conforming changes to the indemnity agreement. Therefore, the requirements of 10 CFR54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewed license for a nuclear facility shall include an integrated plant assessment (IPA), current licensing basis (CLB) changes during NRC review of the application, an evaluation of time-limited aging analyses (TLAAs) and a final safety analysis report (FSAR) supplement. In 10 CFR 54. 22, the Commission states requirements regarding technical specifications. The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with the NRC's regulations and the guidance provided by the draft standard review plan entitled "Review of License Renewal Applications for Nuclear Power Plants," which was published in September 1997. The staff's evaluation of the license renewal application in accordance with 10 CFR 54.21 and 54.22 are contained in Chapters 2, 3, and 4 of this report.

The staff's evaluation of the environmental information required by 10 CFR 54.23 can be found in the draft and final plant-specific supplements to the GEIS, NUREG-1437, Supplement 1, that state the considerations related to renewing the license for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2.

The report by the Advisory Committee on Reactor Safeguards required by 10 CFR 54.25 is included in Chapter 5 of this SER. The finding required by 10 CFR 54.29 is contained in Chapter 6 of this report.

1.4 Summary of Open and Confirmatory Items

As a result of its initial review of the license renewal application for Calvert Cliffs, including the additional information provided to the NRC, the staff identified a number of open issues and confirmatory items when this report was issued in March 1999. This report has been revised to include a description, in each applicable section, of the manner by which those matters have been resolved.

2 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

2.1 Methodology for Identifying Structures and Components Subject to an Aging Management Review

Applicants for license renewal are required by the license renewal rule to perform, among other things, an integrated plant assessment (IPA). The first two steps of the IPA, 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(2), require the applicant to identify and list, from those systems, structures, and components (SSCs) within the scope of the license renewal rule, those structures and components that are subject to an aging management review and to describe and justify the methods used to determine those structures and components subject to review. SSCs within the scope of the license renewal rule are those meeting the criteria in 10 CFR 54.4. Structures and components subject to an aging management review are those that meet the criteria of 10 CFR 54.21(a)(1)(i) and (ii).

In a letter dated August 18, 1995, BGE (the applicant) submitted its "Integrated Plant Assessment Methodology," which was subsequently amended to incorporate changes required by the staff. The amendment to the IPA was submitted in a BGE letter dated January 11, 1996. The staff reviewed this methodology and found it acceptable as documented in a Final Safety Evaluation (FSE) dated April 4, 1996. The BGE license renewal application (LRA) dated April 8, 1998, contains the IPA methodology, technically unchanged from that previously submitted in Attachment 1, Appendix A, Section 2. The staff concluded in its FSE that:

> The BGE methodology sufficiently describes and justifies an acceptable process for identifying structures and components at Calvert Cliffs, Units 1 and 2, that are subject to an aging management review for license renewal and therefore would meet the requirement of 54.21(a)(2). In addition, this process, if implemented, provides reasonable assurance that all structures and components subject to an aging management review pursuant to 10 CFR 54.21(a)(1) will be identified.

The staff's evaluation of the implementation of the process for identifying SSCs that are subject to an aging management review pursuant to 10 CFR 54.21(a)(1) is contained in Section 2.2 of this safety evaluation report (SER).

2.2 Identification of Structures and Components Subject to an Aging Management Review

2.2.1 Introduction

In Sections 3 through 6 of Appendix A, "Technical Information," to the LRA, BGE (the applicant) described the structures and components that are subject to an aging management review (AMR) for license renewal. The staff reviewed these sections of the application to determine if there is reasonable assurance that the applicant has identified and listed those structures and components subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.2 Staff's Approach to the Evaluation

The staff reviewed Sections 3 through 6 of Appendix A to the LRA to determine if there is reasonable assurance that the applicant has appropriately identified and listed those structures and components subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1). The statements of consideration (SOC) for the license renewal rule (60 FR 22478) indicate that an applicant has the flexibility to determine the set of structures and components for which an AMR is performed, provided that this set encompasses the structures and components for which the Commission has determined an AMR is required. Accordingly, the staff focused its review on verifying that the implementation of the applicant's methodology discussed in Section 2.1 of this staff SER did not result in the omission of structures and components subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff performed the following two-step evaluation:

(1) The first step was to determine whether the applicant has properly identified the systems, structures, and components (SSCs) within the scope of license renewal, pursuant to 10 CFR 54.4. As described in more detail below, the staff reviewed selected structures and components that the applicant did not identify as within the scope of license renewal to verify that they do not have any intended functions.

(2) The second step was to determine whether the applicant has properly identified the structures and components (S&Cs) subject to an AMR from among those identified in the first step. As described in more detail below, the staff reviewed selected S&Cs that the applicant identified as within the scope of license renewal to verify that the applicant has identified these S&Cs as subject to an AMR if they perform intended functions without moving parts or without a change in configuration or properties and are not subject to replacement on the basis of a qualified life or specified time period. To determine whether the applicant identified the S&Cs subject to an AMR, the staff did not review S&Cs that the applicant had identified as subject to an AMR because it is an applicant's option to include more S&Cs than those required by 10 CFR 54.21(a)(1).

The staff used the Calvert Cliffs Updated Final Safety Analysis Report (UFSAR) in performing its review. Pursuant to 10 CFR 50.34(b), the FSAR contains "[a] description and analysis of the structures, systems, and components of the facility, with emphasis upon performance requirements, the bases, with technical justification therefor, upon which such requirements have been established, and the evaluations required to show that safety functions will be accomplished." The FSAR is required to be updated periodically pursuant to 10 CFR 50.71(e). Thus, the UFSAR contains updated plant-specific licensing-basis information regarding the systems, SSCs, and their functions.

2.2.3 Systems, Structures, and Components

The applicant presented its methodology (i.e., the integrated plant assessment (IPA)) to identify the systems, structures, and components (SSCs) within the scope of license renewal in

Section 2.0 of Appendix A to the LRA. This IPA methodology consists of a review of all plant systems and structures to determine those that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. The staff reviewed the IPA methodology, and in a letter to the applicant dated April 4, 1996, the staff concluded that the methodology was acceptable for meeting the requirements of 10 CFR 54.21(a)(2) and, if implemented, offered reasonable assurance that all structures and components subject to an aging management review (AMR), as required by 10 CFR 54.21(a)(1), would be identified. Additionally, the letter stated that the staff concluded that the methodology provides processes for demonstrating that the effects of aging would be adequately managed pursuant to 10 CFR 54.21(a)(3) and for evaluating time-limited aging analyses pursuant to 10 CFR 54.21(c) that are conceptually sound and consistent with the intent of the license renewal rule.

To ensure that the IPA methodology described in Section 2.0 of Appendix A to the LRA properly implemented and identified the systems and structures within the scope of license renewal, the staff performed the following additional review. The staff compared the list of systems and structures at the Calvert Cliffs Nuclear Power Plant (CCNPP) listed in Table 3-1 in Section 2.0 of Appendix A to the LRA, to a list of the 66 systems and structures identified by the applicant as conforming to the scoping requirements of 10 CFR 54.4. The staff identified those systems and structures not included within the scope of license renewal and reviewed the information contained in the UFSAR for a sample of these systems and structures to determine whether they performed any intended function defined by 10 CFR 54.4, and thus would be required to be included within the scope of license renewal. The staff found no omissions. However, to ensure the applicant did not omit any system or structures with intended functions, by letter dated August 27, 1998, the staff requested additional information about eight systems and structures outside the scope of license renewal. In response to the staff's request for additional information, on November 2, 1998, the applicant submitted additional information about the five systems and three structures. For each system and structure, the applicant submitted a general description, listed the specific intended functions (active and passive), and identified the portion of the LRA in which the system's components were reviewed (if the system or structure performed an intended function). For example, the staff requested additional information about the reactor protective system. In its response, the applicant identified the three passive intended functions performed by this system and added that the components within the scope of license renewal that performed this intended function were evaluated in either Section 6.2, "Electrical Commodities"; Section 5.9, "Feedwater System"; or Section 6.1, "Cable Commodities."

The staff reviewed the information submitted by the applicant in the LRA and additional information submitted in response to the NRC's August 27, 1998, memorandum, and did not find any systems or structures with intended functions that were not already evaluated in the LRA. Therefore, the staff has reasonable assurance that the applicant had appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.2.3.1 Component Supports Commodity Group

In Section 3.1, "Component Supports," of Appendix A to the LRA, the applicant described the systems with component supports at CCNPP that are within the scope for license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.1.1 Summary of Technical Information in the Application

As described in the LRA, component supports are associated with almost every plant system. A component support is the connection between a system, or a component within a system, and a plant structural member. Because component supports perform the same basic function regardless of the system, the applicant reviewed these components as a commodity group.

The applicant prepared a generic list of component supports by reviewing industry and plant-specific information, including the Seismic Qualification Utility Group guidance, American Society of Mechanical Engineers, Section XI, component support inspection documentation, and the CCNPP system level scoping results for license renewal. The applicant identified all component support types that provide support to plant components that are within the scope of license renewal and listed them as being within the scope of license renewal. The applicant identified 48 systems within the scope of license renewal that contained supports within this commodity group evaluation.

The applicant grouped the total population of component supports into four categories. The categories include supports for both the distributive portions of systems (e.g., piping and cable raceways) and for system equipment. The categories are defined by the components they support: piping; cable raceways; heating, ventilating, and air conditioning ducting; and equipment. These four categories are further separated into 19 sub-categories based on similarities of physical characteristics, loading conditions, and environment.

The applicant identified the following intended functions for the component supports within the scope of license renewal:

- Provide structural support for systems and components required to remain functional during and following design-basis events.
- Provide structural support for systems and components whose failure could prevent satisfactory accomplishment of safety functions for items identified in the preceding category.
- Provide structural support for systems and components that are required for fire protection, environmental qualification, pressurized thermal shock, anticipated transient without scram, and station blackout.

The applicant identified the following component supports within the scope of license renewal that are evaluated elsewhere in Appendix A to the LRA:

- Supports for the steam generators (other than the snubbers) and the reactor vessel, evaluated in Sections 4.1 and 4.2 of Appendix A to the LRA
- Spent fuel pool cooling demineralizer and filter vessel supports, evaluated in Section 5.18 of Appendix A to the LRA.
- Jet impingement barriers and whip restraint supports for high energy line break analysis, evaluated in Section 3.3 of Appendix A to the LRA with the structure that houses the individual component
- Tubing supports, evaluated in Section 6.4 of Appendix A to the LRA

The applicant noted that all of the intended functions listed above are passive because they accomplish their function without moving parts or a change in configuration or property. The applicant therefore concluded that all component supports within the scope of license renewal are also subject to an AMR.

On the basis of the intended functions listed above, the applicant identified the following 19 component support types from the component support groups within the scope of license renewal as being subject to an AMR:

COMMODITY SUPPORT GROUPS AND TYPES	
Piping Supports	Spring hangers, constant load, snubber supports—OC
	Spring hangers, constant load, snubber supports—IC
	Piping frames and stanchions—OC
	Piping frames and stanchions—IC
Cable Raceway Supports	Trapeze, cantilever, other supporting styles—OC
	Piping frames and stanchions—IC
HVAC Ducting Supports	HVAC ducting supports—OC
	HVAC ducting supports—IC
Equipment Supports	Elastomer vibration isolators—OC
	Electrical cabinet anchorage—OC
	Electrical cabinet anchorage—IC
	Equipment frames and stanchions—OC

	Equipment frames and stanchions—IC
	Frames and saddles—OC
	Frames and saddles—IC
	Metal spring isolators and fixed bases—OC
	Metal spring isolators and fixed bases—IC
	Loss-of-coolant accident restraints—IC
	Ring foundations for flat-bottomed vertical tanks—OC

OC - Outside Containment, IC - Inside Containment

2.2.3.1.2 Staff Evaluation

The staff reviewed Section 3.1 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the component supports within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, by letter dated September 7, 1998, the staff issued a request for additional information (RAI) regarding component supports, and by letter dated November 19, 1998, the applicant responded to the RAI.

2.2.3.1.2.1 Component Supports Within the Scope of License Renewal

In the first step of its evaluation, the staff reviewed the information submitted by the applicant in the LRA to identify if there were systems or portions of systems with component supports that the applicant failed to identify as within the scope of license renewal that should have been so identified. The applicant stated in the LRA that 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. The staff compared Table 3.1-1, which is found in Section 3.1 of Appendix A to the LRA, with Table 3-1, which is found in Section 2.0 of Appendix A to the LRA, to determine if the applicant omitted any component supports when compiling its list of such systems within the scope of license renewal. The staff also sampled selected systems not listed in Table 3.1-1 to verify that they do not have any intended functions as defined in Section 3.1 of Appendix A to the LRA.

To help ensure that all systems with component supports within the scope of license renewal were listed in Table 3.1-1, the staff requested more detailed information from the applicant. In NRC Question Nos. 3.1.1 and 3.1.8, the staff noted seven systems in Table 3-1 of Section 2.0 of Appendix A to the LRA that were within the scope of license renewal but that did not appear in Table 3.1-1 of Section 3.1. The applicant responded that two of the systems were within the scope of license renewal, but contained no component supports; one was a portion of a system already listed in Table 3.1-1 (SG blowdown system is part of the MS system); three systems were evaluated in other commodity or system reports (e.g., the containment isolation group's individual containment penetrations are evaluated in each individual system's section); and one system was determined to be outside the scope of license renewal and, therefore, its component supports were outside the scope. One system, diesel generator building HVAC system, was inadvertently omitted from Table 3.1-1. The applicant corrected this error in its November 19, 1998, response to the staff's RAI, by adding the diesel generator building HVAC component supports to Table 3.1-1.

In NRC Question No. 3.1.4, the staff requested clarification on whether steel structural frames used for the support of piping systems were treated as component supports or as structural components. In its response, the applicant stated that the piping support frames were considered component supports and were discussed in Section 3.1 of Appendix A to the LRA. Information regarding the boundary of commodity supports was requested in NRC Question No. 3.1.6, specifically, were fasteners included, and if fasteners have welded connections, are they included within the scope of the components commodity report. The applicant clarified in its response that fasteners and attachments associated with the component side of the component support are evaluated in the component supports commodity group. Fasteners on the structure side of the component support are evaluated in both the component support commodity evaluation and in the evaluation for the specific structure. Welds and fasteners were not identified specifically, rather, they were considered part of the support.

As described above, the staff has reviewed the information in Section 3.1 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the component supports within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.1.2.2 Component Supports Subject to an Aging Management Review

In Table 3.1-1 of Appendix A to the LRA, the applicant identified systems and their associated component supports within the scope of license renewal. In Section 3.1.1.1 of Appendix A to the LRA, the applicant stated that because these component supports performed their intended function without moving parts or without a change in configuration or properties, they have passive intended functions. Therefore, all component supports (except for snubbers, which were excluded as "active" equipment by 10 CFR 54.21(a)(1)(i)), are within the scope of license renewal. The applicant further clarified that 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 and are subject to an AMR. Table 3.1-2 of Appendix A to the LRA summarizes all the component support types requiring an AMR. The staff agrees with the applicant's inclusion of all the component support types listed in Table 3.1-2 as requiring an AMR.

The staff reviewed the information in Section 3.1 of Appendix A to the LRA and has determined that there is reasonable assurance that the applicant has appropriately identified the component supports subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.2 Piping Segments That Provide Structural Support

In Section 3.1A, "Piping Segments That Provide Structural Support," of Appendix A to the LRA, the applicant described the piping segments that provide structural support and that are within the scope for license renewal and identified which of those piping segments are subject to an AMR.

2.2.3.2.1 Summary of Technical Information in the Application

Systems that have safety-related/non-safety-related (SR/NSR) boundaries or changes in piping classification have a boundary valve at the functional transition point. The structural integrity of the boundary valve, which functions as the system pressure boundary, must not be compromised. To ensure proper seismic structural support if the valve itself is not anchored, the system's structural boundary must be extended beyond the boundary valve to the first seismic anchor (or equivalent) and must include the pipe segment connecting the boundary valve to the pipe support. These components together act as a single support system, ensuring the integrity of the SR/NSR functional boundary under all design-basis conditions.

Providing structural support under all current licensing-basis design loading conditions for safety-related components (within the scope of license renewal) is the only intended function identified by the applicant for these piping segments. Because the intended function is performed without moving parts or a change in configuration or properties, it is a passive intended function and, therefore, piping segments that provide such support are subject to an AMR.

All fluid systems containing safety-related piping are within the scope of license renewal. These systems have the potential for having SR/NSR functional boundaries where piping segments beyond the functional boundary would be credited for structural support of the boundary. The applicant reviewed all of the fluid systems at CCNPP and identified those systems with safety-related piping in Table 3.1A-1 of Appendix A to the LRA. A total of 25 systems were identified as having the potential for SR/NSR functional boundaries with seismic boundaries extending beyond them for structural support.

2.2.3.2.2 Staff Evaluation

The staff reviewed Section 3.1A of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the piping segments providing structural support within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.2.2.1 Piping Segments That Provide Structural Support Within the Scope of License Renewal

To determine which piping segments are credited with providing structural support for boundary valves and isolation points at SR/NSR boundaries, the staff performed the following reviews. The staff compared Table 3.1A-1 in Section 3.1 of Appendix A to the LRA and Table 3-1 in Section 2.0 of Appendix A to the LRA to determine if the applicant omitted any safety-related fluid systems when compiling its list of systems to evaluate for functional boundaries. The applicant considers all piping segments beyond the SR/NSR functional boundary that perform the intended function of providing structural support to the safety-related piping and boundary isolation valve or isolation point as being within the scope of license renewal. The staff also reviewed the UFSAR to determine if there were CCNPP fluid systems that might perform safety-related functions or other intended functions as described in 10 CFR 54.4 that were not identified in Table 3.1A-1. The staff sampled CCNPP fluid systems not included in Table 3.1A-1 to determine if the applicant had omitted any systems having the potential for safety-related or non-safety-related functional boundaries. No omissions were identified.

Safety-related systems have the potential for SR/NSR functional boundaries where non-safety-related piping segments may provide structural support beyond the functional boundary. The LRA identified the safety-related fluid systems that have the potential for SR/NSR functional boundaries with structural boundaries extending beyond the functional boundaries within the scope of license renewal. As described above, the staff reviewed the information in Section 3.1A of Appendix A to the LRA and concluded that there is reasonable assurance that the applicant has appropriately identified the piping segments providing structural support to safety-related piping and boundary valves within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.2.2.2 Piping Segments That Provide Structural Supports Subject to an Aging Management Review

In Table 3.1-1 of Appendix A to the LRA, the applicant identified systems within the scope of license renewal with the potential for containing piping segments beyond SR/NSR boundaries that provide structural support to the safety-related piping and boundary isolation valve or isolation point. In Section 3.1.A.1.1 of Appendix A to the LRA, the applicant stated that because these portions of piping segments performed their intended function without moving parts or without a change in configuration or properties, they have passive intended functions. Therefore, all of these piping segments are included within the scope of license renewal and are subject to an AMR. The staff agrees with the applicant's inclusion of all these piping segments as requiring an AMR.

The staff has reviewed the information in Section 3.1A of Appendix A to the LRA. On the basis of the staff's review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the piping segments that provide structural supports subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.3 Fuel Handling Equipment and Other Heavy Load Handling Cranes

In Section 3.2, "Fuel Handling Equipment (FHE) and Other Heavy Load Handling Cranes (HLHCs)," of Appendix A to the LRA, the applicant described structures and components of the FHE and HLHCs that are within the scope of license renewal (10 CFR 54.4). The applicant also identified which of those within-scope structures and components are subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i) and (ii). By a letter to the NRC dated February 4, 1999, the applicant supplemented the scope of Section 3.2 by identifying additional structures and components that are within the scope of license renewal and subject to an AMR. In addition, the staff issued RAIs by letter dated August 26, 1998, regarding the FHE and HLHC commodity report. By letter dated November 4, 1998, the applicant responded to the staff's RAIs.

The staff reviewed Section 3.2, of Appendix A to the LRA, against the requirements of 10 CFR 54.4 (a)(1), (2), and (3) and 10 CFR 54.21(a)(1)(i) and (ii). More specifically, the staff focused its review on determining whether there is reasonable assurance that the applicant identified and listed (1) FHE and HLHC structures and components that are within the scope of license renewal and (2) FHE and HLHC structures and components that are subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.3.1 Summary of Technical Information in the Application

The applicant stated that the structures and components of the FHE and HLHCs are common to many systems. Therefore, the applicant's evaluation is presented in Section 3.2 of Appendix A to the LRA as a separate commodity report on all the FHE and HLHC structures and components within the plant. Some of the FHE and HLHC structural type components, as discussed later in this section of the SER, are identified in Section 3.2 but are evaluated in the individual system sections or buildings in which they are housed.

The FHE and HLHC commodity report addresses (1) all structures and components involved in fuel handling and transfer and (2) cranes that routinely lift heavy loads over safety-related equipment. The applicant identified seven systems with structures and components that define the FHE and HLHC that are within scope for license renewal: (1) spent fuel storage (spent fuel pool), (2) refueling pool, (3) new fuel storage and elevator, (4) spent fuel cask washing pit, (5) fuel transfer tube, (6) fuel handling system, and (7) cranes. These major systems are described as follows:

(1) Spent Fuel Storage System: The CCNPP Units 1 and 2 spent fuel storage system (SFSS), or spent fuel pool (SFP), is located in the auxiliary building and consists of the SFP, the spent fuel shipping cask pit (within the SFP), the spent fuel shipping cask support platform, the SFP work platform, and SFP storage racks.

- The SFP is located outside the containment in the auxiliary building and provides underwater storage for 1830 spent fuel assemblies and one spent fuel shipping cask. It is designed in two halves, north and south for Units 1 and 2, respectively, and is constructed of reinforced concrete lined with stainless steel (SS).

- The spent fuel shipping cask pit is an integral part of the SFP and is located on the Unit 1 side of the SFP. It is used to house the cask during loading with spent fuel bundles.

- The spent fuel shipping cask support platform is a SS energy-absorbing cask support platform upon which the cask is set before being loaded with spent fuel bundles. It is located on the floor of the spent fuel shipping cask pit. The cask support platform is made of a SS shell that encloses an aluminum honeycomb material.

- The SFP platform is a portable work platform 16 feet long x 4 feet wide. It is used to perform various maintenance, testing, and inspection activities in the SFP. For example, the platform is used during repair of spent fuel assembly guide tubes, and the performance of eddy current tests. It is constructed of aluminum decking with SS structural members and can be located along designated walls of the SFP.

- The SFP storage racks are fabricated of SS and boron carbide sheets and are in 10x10, 8x10, and 7x10 arrays in the Unit 1 pool and 10x10 arrays in the Unit 2 pool. The racks meet the requirements of seismic Category I.

(2) Refueling Pool: CCNPP's refueling pool is constructed of reinforced concrete and lined with SS. It is located around the upper portion of the reactor vessel and filled with water from the refueling water storage tank by the SFP cooling pumps. The refueling pool is connected to the SFP by the fuel transfer tube, the safety injection system, and the spent fuel pool cooling system.

(3) New Fuel Storage System and Elevator: The new fuel storage system consists of the new fuel dry storage racks and the new fuel inspection machine (new fuel storage inspection platform). It does not include the new fuel elevator which is part of the fuel handling system discussed under item 6 below. New fuel is removed from its shipping cask using the spent fuel cask handling crane and transferred to the storage racks. Each rack provides storage for 144 fuel assemblies (two-thirds of a core). New fuel is stored in the SFP as space allows. The new fuel inspection machine is located near the new fuel storage area. The new fuel inspection machine is designed to automatically check the straightness and sectional size of a fuel bundle through its full length.

(4) Spent Fuel Cask Washing Pit: The spent fuel cask washing pit is constructed of reinforced concrete lined with SS and provides for storage and decontamination of spent fuel transfer/shipping casks. (This component is evaluated in Section 3.3E of Appendix A to the LRA.)

(5) Fuel Transfer Tube: The fuel transfer tube connects the refueling pool with the SFP and accommodates the transfer of fuel between the two areas. (This component is evaluated in Section 3.3A of Appendix A to the LRA.)

(6) Fuel Handling System: The fuel handling system contains those components used to move fuel from the time new fuel is received until the spent fuel is stored in the SFP. The system includes (a) the new fuel elevator, (b) the spent fuel handling machine, (c) fuel upending machines, (d) the transfer carriage, (e) the reactor refueling machine, and (f) the spent fuel inspection elevator. These components are described as follows:

- The New Fuel Elevator—The new fuel elevator is used to lower 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.

- 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.

- 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 a horizontal position, as required.

- 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 SS 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.

- 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 one to coordinate the location for the fuel handling mast and hoist assembly over the fuel in the core. 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.

- 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 at which adequate water for shielding is available. The spent fuel inspection elevator is located in the Unit 2 end of the SFP.

(7) Cranes: The crane system is described as all cranes, monorails, and hoisting and jib equipment at CCNPP. The applicant stated that there are approximately 85 cranes in the plant and grouped them into three types: overhead gantry cranes, monorail systems and underhung cranes, and overhead hoists. The applicant further grouped the components of the cranes into mechanical components and electrical components. The mechanical components 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, contacts, electric lift and drop sections, motor starters, and control panels. The applicant also identified the specially designed structural load handling devices such as the lifting rig for the reactor vessel cooling shroud and the reactor vessel head (reactor vessel internals system) as structural components in the crane system.

As noted above, two of the systems identified as within scope for license renewal are addressed in other sections of Appendix A to the LRA.

In the LRA, the applicant identified the following intended functions for the above noted structures and components in the FHE and HLHC based on the requirements of 10 CFR 54.4(a)(1) and (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 required safety-related functions; and

- Provide structural and/or functional support for lifting heavy loads over the SFP.

The applicant also determined that there are no intended functions of the FHE and HLHC based on the requirements of 10 CFR 54.4(a)(3).

On the basis of its evaluation of the structures and components that provide the intended functions noted above, the applicant identified a total of 57 structural components/ subcomponents that are within the 5 systems and/or structures and components that constitute the FHE and HLHC and are within scope for license renewal and subject to an AMR.

As discussed in the LRA and the UFSAR, the FHE and HLHC structural components are designated as safety-related and are designed to meet seismic Category I criteria because they must remain functional before, during, and after a safe-shutdown earthquake. Therefore, most of FHE and HLHC structural components perform the first and second intended functions noted above. For example, the SFP is designed to maintain structural integrity during a seismic event in order to support spent fuel in the SFP. Also, the SFP storage racks are designed to withstand all anticipated loadings and are separated in such a manner as to preclude a reduction in separation space under either operating-basis or safe-shutdown earthquake.

In addition, the applicant cited five major cranes in the crane system that handle heavy loads that are functionally not safety-related, but are considered safety-related because they are used to handle heavy loads in the vicinity of the reactor vessel, near spent fuel in the SFP, or in areas in which, if a load is dropped, could damage safe-shutdown or decay-heat-removal equipment. These cranes are the polar crane, the intake structure semi-gantry crane, the transfer jib machine crane, the containment purge exhaust monorail hoist, and the spent fuel cask handling crane (SFCHC).

These cranes are categorized as seismic Category I/II and satisfy the intended functions as noted above. The SFCHC crane (auxiliary building crane) is also designed in accordance with the single-failure-proof criteria in NUREG-0554, "Single-Failure-Proof Cranes for Nuclear Power Plants," and NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants."

In Table 3.2-1 of Appendix A to the LRA, the applicant listed 48 of the 57 components and subcomponents that are identified for an AMR. The remaining 9 structures and components are structural-type components that are addressed in Section 3.3 of Appendix A to the LRA where they are treated for their intended functions as part of the buildings in which they are housed. Those 9 components are (1) polar crane girders, (2) spent fuel cask handling crane rail/support girders, (3) refueling pool reinforced concrete, (4) refueling pool SS liner, (5) fuel transfer tube SS liner, (6) spent fuel pool reinforced concrete, (7) spent fuel pool SS liner, (8) spent fuel pool storage racks, and (9) new fuel storage racks.

2.2.3.3.2 Staff Evaluation

The staff reviewed Section 3.2 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the FHE and HLHC components and supporting structures that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.3.2.1 Fuel Handling Equipment and Other Heavy Load Handling Cranes Within the Scope of License Renewal

The staff reviewed Section 9.7, "Fuel and Reactor Component Handling Equipment," of the UFSAR to determine if there were any additional portions of the structure and other components that the applicant should have identified as within the scope of license renewal. The staff also reviewed Section 9.7 of the UFSAR for any safety-related functions that were not identified as intended functions in the LRA to verify that no structure or component having an intended function was omitted from the scope of the rule.

The staff has reviewed the information presented in Section 3.2 of Appendix A to the LRA and Section 9.7 of the UFSAR. Table 3.2-1 of Appendix A to the LRA shows that all of the FHE and HLHC structures and components that comprise the 48 structural component types within the scope of license renewal require an AMR. Upon completing the initial review, the staff issued RAIs by letter dated August 26, 1998, regarding the FHE and HLHC commodity report. By letter dated November 4, 1998, the applicant responded to the staff's RAIs. As documented by a letter from BGE to NRC, dated February 4, 1999, an additional component type, the containment purge exhaust monorail, was added to the list of components that are within the scope of license renewal and subject to an AMR. In addition, the HLHC carbon steel chain hoist for the containment purge exhaust monorail is identified as a subcomponent that is within the scope of license renewal and subject to an AMR. The staff agrees that this non-safety-related component does perform the intended functions as defined in 10 CFR 54.4(a)(1), (2), and (3), and is within the scope of license renewal. On the bases discussed above, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the FHE and HLHC and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.3.2.2 Fuel Handling Equipment and Other Heavy Load Handling Cranes Subject to an Aging Management Review

In accordance with the license renewal rule, the following structures and components are subject to an AMR: (1) those that perform an intended function without moving parts or without change in configuration or properties, and (2) those that are not subject to periodic replacement based on a qualified life or specified time period.

The applicant's process determined that some structural devices, such as drums, hydraulic cylinders, and wheels, perform their intended function(s) while in motion. Such devices were considered to be active subcomponents and were eliminated from an AMR. It was assumed that no structural components or subcomponents in the fuel handling equipment (FHE) and heavy load handling cranes (HLHCs) were replaced on the basis of time or qualified life.

On the basis of the results of the process described above, the portion of the FHE and HLHCs that is within the scope of license renewal and subject to an AMR includes 57 structural components and their supports.

The following FHE and HLHC components are addressed for their structural intended function(s) as parts of the building in which they are housed in Section 3.3 of Appendix A to the LRA, and are, therefore, not reviewed in this section:

- PC girders
- SFCHC rail/support girders
- refueling pool reinforced concrete
- refueling pool SS liner
- fuel transfer tube SS liner
- spent fuel pool reinforced concrete
- spent fuel pool SS liner
- spent fuel pool storage racks, and
- new fuel storage racks

The remaining 48 components, listed in Table 3.2-1 in Appendix A to the LRA are subject to an AMR and are evaluated within this section. The staff reviewed the information submitted by the applicant and verified that the grouping was correct. Therefore, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the FHE and HLHC's in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4 Primary Containment Structure

In Section 3.3A, "Primary Containment Structure," of Appendix A to the LRA, the applicant describes portions of the primary containment and the components therein that are within the scope of license renewal, and identified which of those within-scope components are subject to an AMR.

2.2.3.4.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the primary containment is designed to withstand an internal pressure of 50 psig with a coincident concrete surface temperature of 276 °F, and to limit leakage to no more than 0.20 percent 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. The primary containment consists of two categories of components — the containment structure and the containment system. The containment structure embraces the majority of structural components, such as beams, columns, walls, and liners. The containment system covers penetrations, hatches, air locks, and associated instrumentation.

In Appendix A to the LRA, the applicant identified the following intended functions for the primary containment in accordance with 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Serve as a pressure boundary or a fission-product retention barrier to protect public health and safety during a design-basis event;
- Provide shelter/protection to safety-related equipment;
- Provide structural and functional support or both to safety-related equipment;
- Serve as a missile barrier (internal or external);
- Provide structural and functional support or both to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions; and
- Provide flood protection barrier (internal flood event).

The applicant also determined that the following were intended functions of the primary containment according to the requirements of 10 CFR 54.4(a)(3):

- For station blackout — Provide closure of containment airlock and access/egress hatches;
- For equipment qualification — Provide boundaries of harsh environment applicable to the functionality of electrical components as addressed by the equipment qualification program; and
- For fire protection — Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.

On the basis of the intended functions stated above, the applicant identified a total of 37 structural component types as being within the scope of license renewal. These structural component types were further combined into the following 4 structural component categories on the basis of their design and materials: (1) concrete, (2) structural steel, (3) architectural, and (4) unique (e.g., post-tensioning system, basemat and containment liner, permanent cavity seal ring, trisodium phosphate baskets, and emergency sump cover and screen). The applicant identified all 37 structural component types as subject to an AMR. The applicant identified the following 3 component types for the containment system: (1) air locks and equipment hatch,

(2) containment penetrations, and (3) limit switches. Of these 3 component types, the applicant identified 2 as subject to an AMR.

The applicant also indicated that some components in the containment system that are common to many systems have been included in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1 of the application;
- Supports for the steam generators and pressurizer, which are evaluated for the effects of aging in Section 4.1 of the application;
- Supports for the reactor vessel, which are evaluated for the effects of aging in Section 4.2 of the application; and
- Electrical control and power cabling, which is evaluated for the effects of aging in Section 6.1 of the application.

2.2.3.4.2 Staff Evaluation

The staff reviewed Section 3.3A of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the primary containment components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.2.1 Systems, Structures, and Components Within the Scope of License Renewal

The staff reviewed Section 5.1, "Containment Structure," of the UFSAR and compared the description of the structures and components in the UFSAR to the description in the application to determine if there were any portions of the structure, and other components, that the applicant should have identified as within the scope of license renewal. The staff also reviewed Section 5.1 to determine if there are any safety-related functions that were not identified as intended functions in the LRA to determine if there are any structures or components with intended functions that might have been omitted from the scope of license renewal. On the basis of its review, the staff found that the applicant did not omit anything.

Table 3.3A-1 of Appendix A to the LRA shows that all of the containment structure components that comprise the 37 structural component types within the scope of license renewal also require an AMR. As mentioned in Section 2.2.3.17.2.1 of this SER, the containment sump, trisodium phosphate baskets, and the emergency sump cover and screens were adequately identified in

Table 3.3A-1 as requiring an AMR. Only one of the three component types within the scope of license renewal for the containment system did not require an AMR. The component type, limit switches, was found to only support the active function of providing closure of the containment air lock and access/egress hatches during a station blackout. In performing their functions, limit switches change configuration; therefore, the limit switches do not require an AMR. The remaining component types requiring an AMR are shown in Table 3.3A-2 of Appendix A to the LRA. On the basis of the components identified in the tables referenced above and the supporting information in Section 5.1 of the USAR, the staff concludes that those portions of the primary containment structure that are not identified as within the scope of license renewal do not perform any intended functions.

As noted above, the staff has reviewed the information in Section 3.3A of Appendix A to the LRA and Section 5.1 of the USAR. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the primary containment and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.4.2.2 Primary Containment Structures Subject to an Aging Management Review

Of 45 component types within the scope of the license renewal rule, 37 are structural component types and are identified in Table 3.3A-1. The remaining 8 are system component types, 7 of which are identified in Table 3.3A-2, and the eighth is a limit switch. The staff reviewed the component types that are electrical/instrumentation components to verify that the applicant did not miss any electrical/instrumentation components that should be subject to an AMR. The applicant classified the limit switch as having only an active function and, therefore, not requiring an AMR. Electrical control/power cabling is evaluated in Section 2.2.3.32, "Cables," of this SER. One electrical/instrumentation component, electrical penetrations, evaluated in this section was classified as subject to an AMR. The staff agrees with this BGE determination covering electrical/instrumentation components, which is consistent with 10 CFR 54.21(a)(1).

Some components in the containment system are common to many other plant systems (e.g., structural supports for piping, cables, electrical control, and power cabling) and have been discussed by the applicant in separate sections of the LRA that address those components as commodities for the entire plant.

On the basis of the applicant's integrated plant assessment (IPA) methodology provided in Appendix A to the LRA and provisions of 10 CFR 54.21(a)(1), the applicant identified 44 component types for the containment structure and component system as components subject to an AMR, and listed these component types in Tables 3.3A-1 (37 structural type components) and 3.3A-2 (7 system type components) of Appendix A to the LRA.

The staff focused its evaluation of the applicant's approach for defining the applicability of an AMR for the containment structure and containment system on the issue of whether the requirements and intent of 10 CFR 54.4 and 54.21(a)(1) are fully complied with. The staff reviewed each of the 44 component types noted above for the containment structure and containment system to verify that these items are part of the containment structure and the containment system. The staff further verified that the applicant had not omitted any items from an AMR that are part of the containment structure and containment system, and that perform an intended function without moving parts or without a change in configuration or properties and are not subject to replacement based on a qualified life or specified time period. The staff also reviewed the manner in which the applicant handled some components in the containment system that are common to many other plant systems and have been reviewed by the applicant in separate sections of the LRA, that address those components as commodities for the entire plant. On the basis of the review described above, the staff concludes that the applicant has implemented an adequate procedure for defining structural and system component types for the CCNPP containment structure and the containment system that are subject to an AMR, because the applicant's approach included 100 percent of the structural and system component types that constitute the CCNPP containment structure and the containment system.

Table 3.3A-1, "Containment Structure Component Types Requiring an AMR," in Appendix A to the LRA designates the containment structural components subject to an AMR. The containment tendon gallery protects the bottom anchorages of the vertical tendons, and gives access to the tendon anchorages for inservice inspection activities. The tendon gallery is categorized as a non-safety-related element of the containment structures. BGE indicated that the tendon gallery is not relied upon for containment integrity in the seismic analyses or design-basis events. Documentation of this basis for excluding the tendon gallery from the scope of the structural elements subject to an AMR was identified as Confirmatory Item 2.2.3.4.2.2-1 in the previous SER.

In its July 2, 1999, response to this issue, the applicant committed to perform the aging management of tendon anchorages through procedures STP-M-663-1and -2, (Containment Tendon Surveillance Tests) and MN-1-319 (Structures and Systems Walkdown). The staff concludes that these procedures provide adequate monitoring of the condition of the tendon anchorages and allow detection of anchorage degradation in sufficient time to correct the degradation before the intended function is compromised. On this basis, the staff concludes that the applicant has provided an acceptable basis to exclude the tendon galleries from an AMR and considers Confirmatory Item 2.2.3.4.2.2-1 closed. The staff notes that managing the condition and environment in the tendon galleries (e.g., moisture and humidity) may be a prudent way to manage the degradation (i.e., corrosion) of bearing plates and other vertical tendon anchorage components in the tendon galleries.

The staff finds that there is reasonable assurance that the applicant has appropriately identified the structural and system component types for the primary containment structure that are subject to an AMR pursuant to 10 CFR 54.21(a)(1).

2.2.3.5 Turbine Building Structure

In Section 3.3B, "Turbine Building Structure," of Appendix A to the LRA, the applicant described the turbine building and noted the components that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.5.1 Summary of Technical Information in the Application

As described in the LRA, the turbine building is within the scope of license renewal because its structural components perform one or more of the following generic functions:

- Provide structural and/or functional support to safety-related equipment;
- Provide shelter/protection to safety-related equipment;
- 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 safety-related 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.

In Section 3.3B.1 of Appendix A to the LRA, the applicant described the turbine building, including the conceptual boundaries, and listed the intended functions performed by its structural components. The applicant then identified the structural component types within the scope of license renewal. Finally, the components subject to an AMR were identified and dispositioned in accordance with the integrated plant assessment methodology described in Section 2.0 of Appendix A to the LRA.

The turbine building for the CCNPP is common to both units and is oriented parallel to the Chesapeake Bay shoreline between the North Service Building and the auxiliary building. It is a steel structure with metal siding supported on reinforced-concrete foundations. The turbine building is a seismic Category II structure. The conceptual boundary of the turbine building includes the AFW pump rooms and portions of the electrical ductbanks that are seismic Category I structures. Since the seismic Category I structures are enclosed within the turbine building that serves such intended functions as providing support and shelter to safety-related equipment, the turbine building and its enclosures are within the scope of license renewal.

The electrical ductbanks that run under the turbine building are connected between the AFW pump rooms and the intake structure. These ductbanks are seismic Category I reinforced-concrete structures that encase the safety-related electrical conduits. The siding on the turbine building wall is not safety-related, but the siding clips that hold the siding in place are safety-related. The siding clips are designed to fail when a differential pressure across the siding reaches a pre-determined pressure, which allows the siding to blow off for venting blowdown pressure following an accident and protects vital equipment and structures within the turbine building. The wall at the end of the main steam pipe tunnel that separates the turbine building and the auxiliary building is designed to fail at 0.5 psi to release pressure if a main steam line breaks near the main steam pipe tunnel. The wall is also designed to fail at a hydraulic pressure of 3 feet of water from a main feedwater line rupture in the main steam piping area.

The applicant identified that the turbine building and the AFW pump rooms are within the scope of license renewal according to 10 CFR 54.4(a). Six of the seven generic structural functions (except for the pressure boundary for fission products) listed in Table 3.3B-1 of Appendix A to the LRA are the intended functions for the turbine building and the AFW pump rooms. As described in the IPA, the applicant developed a generic list of component types for use during the structural component scope task. On the basis of this generic list, the applicant determined 24 structural component types for the turbine building (as listed in Table 3.3B-2 of Appendix A to the LRA) that identify such structural components as walls, slabs, and equipment pads, which do not have unique equipment identifiers in the site equipment database. These structural component types were combined into the following four structural categories on the basis of their design and material:

- concrete components
- structural steel components
- architectural components
- unique components

The structural component types identified for the turbine building contribute at least one of the structural intended functions discussed in the LRA. For example, the electrical ductbanks that run under the turbine building have been identified as structural components under the category of concrete components and are included in the turbine building conceptual boundary because they are seismic Category I. The turbine building siding clips and retainer clips are identified as structural components under the category of architectural components because they are safety related. These structural components that fall within the scope of license renewal are functionally passive and are not subject to periodic replacement. All the structural components listed in Table 3.3B-2 of Appendix A to the LRA are subject to an AMR and are evaluated in this section.

Component supports that are connected to structural components in the turbine building are evaluated in Section 3.1 of Appendix A to the LRA under the component support commodity evaluation. A component support is defined as the connection between a system (or component within a system) and a plant structural member. Component supports interface with the component they support in the applicable systems and interface with the structural component to which they are attached. For example, a fixed base that supports a pump is considered a component support since it connects the concrete equipment pad to the pump. The pump itself would be included and evaluated within the associated system in Appendix A to the LRA. The fixed base would be included within the component support commodity evaluation, and the concrete equipment pad would be included 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 support commodity evaluation and the evaluation for the structural component. Evaluations for structural components considered the effects of aging caused by the surrounding environment; the component support commodity evaluation considered the effects of aging caused by the supported equipment (thermal expansion, rotating equipment, etc.) as well as by 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 (i.e., is included in the scope of the associated structure). All the component supports in the turbine building are evaluated in Section 3.1 of Appendix A to the LRA.

2.2.3.5.2 Staff Evaluation

The staff reviewed Section 3.3B of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the turbine building structural components that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.5.2.1 Systems, Structures, and Components Within the Scope of License Renewal

As part of the first-step evaluation (i.e., to determine whether the applicant has properly identified the systems, structures, and components within the scope of license renewal), the staff reviewed portions of the UFSAR, including the layout drawings for the turbine building, the AFW pump rooms, and the ductbanks, and compared them with the structural components listed in Table 3.3B-2 and shown in Figure 3.3B-1 in Appendix A to the LRA to determine if there were any portions of the structures and associated components that the applicant did not identify as within the scope of license renewal. The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA to determine if there were any structural components having intended functions that might have been omitted from consideration within the scope of license renewal. Although the staff found no omissions, the staff questioned why the turbine building roof trusses were described in the Structural Description portion of Section 3.3B, but not included in Table 3.3B-2, "Structural Component Types Requiring AMR for the Turbine Building."

During a site visit to the CCNPP on February 18, 1999 (summarized in an NRC letter dated March 19, 1999), the staff asked the applicant why the roof trusses were not subject to an AMR. The applicant stated that the roof trusses are not within the scope of license renewal. The applicant explained that the roof trusses are seismic Category II structures, but their failure during an abnormal (e.g. seismic) event could not affect the operability of any safety-related equipment in the turbine building. Therefore, the roof trusses do not meet the scoping criteria of 10 CFR 54.4. The staff reviewed the information and agreed that the roof trusses are not within scope.

On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structural components of the turbine building and the AFW pump rooms that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.5.2.2 Turbine Building Structure Subject to an Aging Management Review

The staff determined whether the applicant has properly identified the structural component types of the turbine building subject to an AMR from among all of the structural component types in the turbine building. The applicant identified 24 structural component types under 4 structural component categories for the turbine building in Table 3.3B-2 in Section 3.3B of Appendix A to the LRA. In the "concrete" category, the structural components are walls, ground floor slabs and equipment pads, elevated floor slabs, cast-in-place anchors/embedments, ductbanks, grout, fluid-retaining walls and slabs, and post-installed anchors. In the "structural steel" category, the structural components are beams, baseplates, floor framing, platform hangers, decking, jet impingement barriers, floor grating, and stairs and ladders. In the "architectural components" category, the structural components are building siding clips, retainer clips, fire doors, jambs, hardware, and caulking and sealants. In the "unique components" category, the structural components are watertight doors, pipe whip restraints, and pipe encapsulations. The staff reviewed the list of 24 structural component types within the scope of license renewal and determined that they perform their intended functions without moving parts or changes in configuration, and are not replaced on a periodic basis.

Based on this review, the staff finds that since all 24 structural component types within the scope of license renewal are subject to an AMR, there is reasonable assurance that the applicant has identified the structural components subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.2.3.6 Intake Structure

In Section 3.3C, "Intake Structure," of Appendix A to the LRA, the applicant described the technical information related to the intake structure at the plant site. The staff reviewed this section of the application to determine if there is reasonable assurance that the applicant has identified and listed those structures and components of the intake structure that are subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.6.1 Summary of Technical Information in the Application

As described in the LRA, 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 12 circulating water pumps that supply water from the Chesapeake Bay to the condensers, and 6 saltwater pumps that provide cooling water to various plant equipment. Trash racks and traveling screens protect the condensers from foreign bodies present in the bay water. A gantry crane, having a lifting capacity of 35 tons, spans the full width of the structure, and is capable of traversing the entire length of the intake structure.

The intake structure is approximately 90 feet x 385 feet, and is constructed primarily of reinforced concrete. The foundation slab varies in elevation from -26 feet 0 inches to -14 feet 3 inches. 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). For all major structures below finish grades, a heavy waterproofing membrane of 40-mil 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. Since the intake structure houses the saltwater pumps that are essential for the 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 from the maximum hypothetical hurricane tide and storm surges, including wave action. The intake structure design loads and conditions are shown in CCNPP UFSAR Section 5A.5. The structure is designed in accordance with American Concrete Institute (ACI) standards and the structural steel components are designed 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 feet 6 inch is made of a reinforced-concrete slab supported on a structural steel frame.

The conceptual boundaries of this evaluation are 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 Appendix A to the LRA. Component supports are defined as the connection between a system, or a 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 is 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; 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. Cranes and fuel handling equipment that are connected to structures are evaluated for the effects of aging in the cranes and fuel handling commodity evaluation in Section 3.2 of Appendix A to the 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 evaluated in this section.

Electrical ductbanks run under the turbine building, and 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 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 served as a convenient pull point during construction for the saltwater pump motor cables. 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 ductbanks are sloped downward toward the intake structure, and the pull boxes have 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 Appendix A to the LRA. The cables are evaluated for the effects of aging in the cables commodity evaluation in Section 6.1 of Appendix A to the LRA.

The intended functions for the intake structure were determined on the basis of the requirements of 10 CFR 54.4(a)(1), (2), and (3), in accordance with Section 4.2.2 of the CCNPP IPA methodology in Section 2.0 of Appendix A to the LRA. In Table 3.3C-1, the applicant indicates that six out of seven of the generic structural functions listed above are applicable to the intake structure.

To identify the structures and structural components, the applicant combined the structural components in four structural categories according to their design and materials as (1) concrete components; (2) structural steel components; (3) architectural components; and (4) unique components.

During the scoping process, the structural component types actually contained in the intake structure were identified within the four structural component categories. Twenty-seven structural component types (e.g., concrete beams and slabs, steel beams, base slabs) were determined to contribute to at least one of the intake structure intended functions. Table 3.3C-2 of Appendix A to the LRA lists these component types and their associated intended functions. Structural component types that are part of the intake structure, but that do not contribute to any of the intended functions of the structure, are not listed in the table.

As discussed in Section 5.4 of the CCNPP IPA methodology in Section 2 of Appendix A to the LRA 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. On this basis, all of the structural component types listed in Table 3.3C-2 are subject to an AMR for the intake structure.

Furthermore, the applicant stated that it may elect to replace components for which an 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 an AMR.

2.2.3.6.2 Staff Evaluation

The staff reviewed Section 3.3C of Appendix A to the LRA to determine if there is reasonable assurance that the applicant has appropriately identified the structures and components in the intake structure within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

The staff used the UFSAR, and the content of Section 3.3C of Appendix A to the LRA in performing its review.

2.2.3.6.2.1 Intake Structure Within the Scope of License Renewal

The basic intake structure is a reinforced-concrete structure whose walls and slabs are 2 feet thick or more. Its basic function is to shelter the safety-related saltwater pumps from severe and extreme natural phenomena, such as earthquakes, winds, and tornados (hurricanes). Its internal components (e.g., slabs, beams) provide supports for the safety-related (SR), and non-safety-related (NSR) components, whose failure could directly prevent the SR components from functioning satisfactorily. It also serves as a flood protection barrier (internal flooding event) and as a rated fire barrier. The applicant has systematically identified seven intended functions for structures and components to comply with the requirements of 10 CFR 54.4(b). Because the intake structure does not serve as a pressure boundary or a fission-product retention barrier, the applicant excluded this from its intended functions. The staff agrees with the applicant's identification of intended functions of the intake structure.

The applicant then established the conceptual boundaries of the intake structure, and discussed the scope of the structures and components to be evaluated under Section 3.3C. The electrical ductbanks that are located between the turbine building and intake structure are evaluated in Section 3.3B of Appendix A to the LRA. Other structures and components that are within the boundary of the intake structure, but not included in the evaluation of the intake structure are:

- The associated pumps are evaluated under the respective systems.

- The fixed bases (normally steel) that support the pumps and connect them to concrete pads are evaluated under the component support commodity evaluation

- The environmental aging effects on the associated anchor bolts are evaluated as the intake structure components; however, the aging caused by the supported equipment is evaluated under the component support commodity evaluation.

- The intake structure's gantry crane rails, girders, and other structural support members are evaluated in Section 3.2 of Appendix A to the LRA.

The intake structure is protected by baffle walls to prevent pleasure craft from entering the intake area. The baffle walls overhang from the embankment and are partially submerged in the intake channel. This facilitates in drawing in a large volume of water from the bottom stratum of the bay with minimal ecological effects. The staff queried the applicant for not including the baffle walls and intake channel in the scope of license renewal. During the staff's site visit on February 17, 1999, (NRC meeting summary dated March 19, 1999), this item was discussed. The applicant emphasized that the functional requirements of these components do not meet any of the scoping criteria, and decided to exclude them from the scope of license renewal. The staff found the applicant's reasoning acceptable, and resolved the issue; therefore, this item is not considered to be an omission on the part of the applicant.

On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the intake structure within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.6.2.2 Intake Structure Subject to an Aging Management Review

During the scoping process, the structural component types in the intake structure were identified within four structural component categories: (1) concrete components, (2) structural steel components, (3) architectural components, and (4) unique components. Twenty-seven structural component types (e.g., concrete beams and slabs, steel beams, base slabs) were determined to contribute to at least one of the intake structure's intended functions.

The applicant has identified the long-lived and passive structures and component types within the intake structure, and the staff 's review did not find any omissions of structures and components that are required to be subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The staff has reviewed the information submitted in Section 3.3C of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structure and components subject to an AMR for the intake structure to meet the requirements of 10 CFR 54.21(a)(1).

2.2.3.7 Miscellaneous Tank and Valve Enclosures

In Section 3.3D, "Miscellaneous Tank and Valve Enclosures," of Appendix A to the LRA, the applicant described the enclosures for tanks and valves at the plant site within the scope for license renewal, and identified which enclosures are subject to an AMR.

2.2.3.7.1 Summary of Miscellaneous Tank and Valve Enclosures Technical Information in the Application

The applicant identified three miscellaneous tank and valve enclosures as being within the scope of license renewal: the No. 12 condensate storage tank (CST) enclosure, the No. 21 fuel oil storage tank (FOST) enclosure, and the auxiliary feedwater (AFW) valve enclosure.

As described in the LRA, the No. 12 CST enclosure houses and protects the No. 12 CST, which provides demineralized water for decay heat removal and cooldown of CCNPP Units 1 and 2. The No. 21 FOST enclosure houses and protects the No. 21 FOST, which provides a fuel supply for the three emergency diesel generators installed in the auxiliary building. The AFW valve enclosure houses and protects the AFW pump suction valves and associated manifold piping, which provide a pressure boundary function for the AFW system. These three enclosures are reinforced-concrete structures of sufficient thickness to protect their associated tanks, valves, or piping from design-basis loadings such as weight, thermal, seismic, and wind.

For each of these miscellaneous tank and valve structures identified by the applicant as being within the scope of license renewal, the applicant identified the following three structural component categories as subject to an AMR: (1) concrete components, (2) structural steel components, and (3) unique components. Within the three applicable structural component categories, 17 structural component types were determined to be subject to an AMR. These 17 structural component types requiring an AMR for the miscellaneous tank and valve enclosures are listed in Table 3.3D-2 of Appendix A to the LRA. The 17 structural component types either (1) provide structural and/or functional support to SR equipment, (2) provide shelter/protection to SR equipment, (3) serve as a missile barrier (internal or external), or (4) provide structural and/or functional support to NSR equipment whose failure could directly prevent satisfactory accomplishment of any of the required SR functions.

2.2.3.7.2 Staff Evaluation

The staff reviewed Section 3.3D of Appendix A to the LRA to determine if there is reasonable assurance that the applicant has identified the miscellaneous tank and valve enclosures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.7.2.1 Miscellaneous Tank and Valve Enclosures Within the Scope of License Renewal

In an attempt to determine whether the applicant has properly identified all of the enclosures at the CCNPP site that are within the scope of license renewal, the staff reviewed Chapters 1 and 5 of the UFSAR for comparison with Figure 3.3D-1 of Appendix A to the LRA, which is a simplified diagram of the CCNPP site structures. On Figure 3.3D-1, the CCNPP site structures within the scope of license renewal are identified as (1) the intake structure, (2) Unit 1 and Unit 2 containment, (3) the auxiliary building, (4) the below-grade electrical ductbank for diesel generator 1A, (5) the safety-related diesel generator building, (6) the No. 12 CST enclosure, (7) the No. 21 FOST enclosure, and (8) the AFW valve enclosure.

The CCNPP site plan, UFSAR Figure 1-2, shows each of the yard structures and tanks in addition to the buildings. The only small enclosures shown on UFSAR Figure 1-2 are the No. 12 CST enclosure and the No. 21 FOST enclosure. The AFW valve enclosure is not shown on UFSAR Figure 1-2; however, this enclosure is listed as one of the seismic Category I structures in Appendix 5a to Chapter 5 of the UFSAR. Other enclosures listed as seismic Category I structures in the UFSAR are the enclosures for the critical service water and saltwater pumps. The staff examined the list of seismic Category I structures since the primary function of tank and valve enclosures is to provide shelter/protection to SR equipment and the seismic Category I classification is required for structures that house SR equipment that must remain functional before, during, or after a safe-shutdown earthquake. The critical service water and saltwater pumps are not covered in Section 3.3D of Appendix A to the LRA since they are considered part of the intake structure, which is covered in Section 3.3C of Appendix A to the LRA.

On the basis of this review, the staff finds that there is reasonable assurance that each of the miscellaneous tank and valve enclosures that house SR equipment at the CCNPP site have been appropriately identified by the applicant as being within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.7.2.2 Miscellaneous Tank and Valve Enclosure Structural Component Types Subject to Aging Management Review

In the second step of its evaluation, the staff determined whether the applicant properly identified the structural component types of the No. 12 CST enclosure, the No. 21 FOST enclosure, and the AFW valve enclosure subject to an AMR from among all of the structural component types that constitute these three enclosures. For these three enclosures the applicable structural component categories are (1) concrete, (2) structural steel, and (3) unique components. Examples of components within these three structural component categories are (1) walls, foundations, and roof slab for the concrete category; (2) beams, baseplates, roof framing, and bracing for the structural steel category; and (3) anchor brackets and manhole framing and cover for the unique component category. On the basis of a staff review of the 17 structural component types listed in Table 3.3D-2 of Section 3.3D of Appendix A to the LRA, the staff concludes that the applicant has identified all of the structural component types of the No. 12 CST enclosure, the No. 21 FOST enclosure, and the AFW valve enclosure that perform an intended function without moving parts or without a change in configuration or properties and are not subject to replacement based on a qualified life or specified time period.

Therefore, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structural component types for the No. 12 CST enclosure, the No. 21 FOST enclosure, and the AFW valve enclosure that are subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.8 Auxiliary Building and Safety-Related Diesel Generator Building Structures

In Section 3.3E, "Auxiliary Building and Safety-Related Diesel Generator Building Structures," of Appendix A to the LRA, the applicant described the auxiliary building, the adjacent emergency diesel generator (EDG) rooms, the refueling water tank (RWT) pump rooms, the safety-related diesel generator building, and the duct bank for EDG 1A, and the components that are within the scope for license renewal, and identified which of those components are subject to an AMR.

2.2.3.8.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, all of the auxiliary building and safety-related EDG building structures identified above are within the scope of license renewal. The applicant determined that these structures were within the scope of license renewal because they perform one or more of the following intended functions:

(1) Provide structural or functional support or both to safety-related equipment.

(2) Provide shelter/protection to safety-related equipment. (NOTE: This function includes protection from (a) radiation effects for equipment addressed by the Equipment Qualification (EQ) Program and (b) high-energy line-break effects.)

(3) Serve as a pressure boundary or a fission product retention barrier in the event of a design-basis event.

(4) Serve as a missile barrier (internal or external).

(5) Provide structural or functional support or both to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions (e.g., seismic Category II over I [II/I] design considerations).

(6) Provide flood protection barrier (internal flooding event).

(7) Provide rated fire barriers to confine or retard a fire from spreading to or from adjacent areas of the plant.

In Section 3.3E of Appendix A to the LRA, the applicant described the auxiliary building and safety-related diesel generator building structures and listed the intended functions performed by each structure. The applicant then used the intended functions to identify the structural component types within the scope of license renewal. Finally, the applicant identified the components subject to an aging management review (AMR) and dispositioned them in accordance with the integrated plant assessment methodology described in Section 2.0 of Appendix A to the LRA.

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 both units. Major structural features related to the nuclear steam supply system (NSSS) and located inside the auxiliary building are the control room, nuclear waste treatment facilities, and facilities for new and spent fuel handling, storage, and shipment. 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. The auxiliary building and adjacent rooms, and their structural components, provide support and shelter to safety-related and non-safety-related equipment. All structural components enclosed within these structures that serve intended functions such as support and shelter are within the scope of license renewal. The applicant noted that those areas inside the auxiliary building that are specifically excluded from seismic Category I requirements in the plant's Quality List (e.g., maintenance shops, stairways, kitchen, toilets, offices) are not within the scope of license renewal. The conceptual boundary of the auxiliary building includes the areas that house safety-related systems, equipment, or components that must remain functional before, during, and after a safe-shutdown earthquake. Additionally, the conceptual boundary includes functional or structural supports for non-safety-related components whose failure during an abnormal (e.g., seismic) event could affect the operability of safety-related components; the associated structural components in the auxiliary building provide support for safety-related mounting of such components. 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.

The safety-related diesel generator building is located northwest of the auxiliary building and is common to both units. It houses EDG 1A, which is one of four EDGs designed to provide a dependable onsite power source under all conditions. The other three EDGs are housed in the rooms adjacent to the auxiliary building described above. The safety-related diesel generator building also houses the fuel oil storage tank (FOST) for EDG 1A and other auxiliary equipment. The safety-related diesel generator building is primarily a reinforced-concrete structure supported on a mat foundation at grade level 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. The conceptual boundary of the safety-related diesel generator building includes all structural components, such as concrete foundations, walls, and slabs, as well as a buried duct bank that runs between the safety-related diesel generator building and the auxiliary building for the electrical distribution for EDG 1A. Portions of the buried duct bank are also common to the SBO diesel generator.

The applicant performed a one-time procedure to evaluate aging management for structural component types within the conceptual boundary of the safety-related diesel generator building. The evaluation produced a listing of structural component types subject to an AMR grouped by materials and environment, and related them to similar groupings in the auxiliary building. Since completion of construction in 1996, evidence of age-related degradation of the safety-related diesel generator building has not been observed. Because the function and structure of the diesel generator building are so similar to the function and structure of the auxiliary building, which was built before the Unit 1 operating license was issued in 1974, operating experience related to aging mechanisms and their management for the auxiliary building is expected to give early warning to the applicant of any aging of the safety-related diesel generator building that will need to be managed.

Components that are connected to structural components in the auxiliary and safety-related diesel generator building structures are evaluated in Section 3.1, "Component Supports," of Appendix A to the LRA. A "component support" is the connection between a system, or a component within a system, and a plant structural member. Component supports interface with the component 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 included within the associated system LRA evaluation. The fixed base would be included within the component supports commodity evaluation, and the concrete equipment pad would be included 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; the component commodity report 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).

The applicant identified that the auxiliary building and safety-related diesel generator building structures are within the scope of license renewal based on 10 CFR 54.4(a). All seven generic structural functions listed above are intended functions for the auxiliary building and adjacent rooms. Six of the seven listed functions (No. 3 is excepted) are intended functions for the safety-related diesel generator building. For the EDG 1A duct bank, only three of the seven functions are intended functions (Nos. I, 2, and 4). These three intended functions are related to structural or functional support or both, shelter/protection, and missile barrier functions. In

Appendix A to the LRA, the applicant identified the first four listed intended functions for these structures on the basis of 10 CFR 54.4(a)(1), the fifth and sixth intended functions on the basis of 10 CFR 54.4(a)(2), and the last on the basis of 10 CFR 54.4(a)(3).

As described in the Integrated Plant Assessment (IPA) (see Section 2.4.2.3, "Structural Component Type Listing for the Structure," of Appendix A to the LRA), the applicant developed a generic list of component types for use during the structural component scoping task. The generic list started with component types associated with safety-related functions contained in technical reports prepared by industry addressing containment and seismic Category I structures. Other structural component types related to fire and flooding events were added to the list to ensure completeness. These structural components were combined into the following four structural categories according to their design and materials:

- concrete components
- structural steel components
- architectural components
- unique components

From within the four structural categories listed above, the applicant determined that 47 structural component types contributed to at least one of the structural intended functions listed above. Of the 47 structural component types within the scope of license renewal for the auxiliary building and safety-related diesel generator building structures, one unique component type, pipe encapsulation, was evaluated in the main steam AMR evaluation as described in Section 5.12, "Main Steam, Generator Blowdown, Extraction Steam, & Nitrogen & Hydrogen Systems," of Appendix A to the LRA. The remaining 46 component types, listed in Table 3.3E-2 of Appendix A to the LRA, are subject to an AMR and are evaluated in this section.

2.2.3.8.2 Staff Evaluation

The staff reviewed Section 3.3E of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the auxiliary building and safety-related diesel generator building structural components that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the subject structures (NRC letter to BGE dated September 7, 1998), and by letter dated November 19, 1998, the applicant responded to those RAIs.

2.2.3.8.2.1 Auxiliary Building and Safety-Related Diesel Generator Building Structures Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including the layout drawings for these structures, to determine if there were any portions of the structures and associated components that the applicant did not identify as within the scope of license renewal. The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in the LRA to verify that structural components having intended functions were not omitted from consideration within the scope of the rule.

As a check to determine if the applicant omitted a component from its list of components that are within the scope of license renewal, the staff asked the applicant to clarify several issues. In NRC Question No. 3.3.43, the staff noted to the applicant that Section 3.3E, "Auxiliary Building and Safety-Related Diesel Generator Building Structures," of Appendix A to the LRA addresses the safety-related diesel buildings but does not address the SBO diesel generator. In its response, the applicant referred to Subsection 4.2.2, "Function Identification," of Section 2.0 of Appendix A to the LRA (i.e., the IPA) and stated that the structure that encloses the SBO diesel generator does not perform any of the seven listed functions and, therefore, is not within the scope of license renewal. However, Section 8.4.5.1.e of the UFSAR states that certain structural components of the SBO diesel generator building are designed to preclude seismic failure and subsequent impact of the structure on the adjacent safety-related EDG building. In addition, as stated in the same UFSAR section, certain equipment located "outdoors or on the building roof" could exceed the parameters for a Spectrum II tornado and has been anchored to resist these wind loads. Function No. 5 in Section 4.2.2 of Section 2.0 of Appendix A to the LRA addresses non-safety-related equipment whose failure may affect the function of safety-related equipment. Therefore, the staff believes that the SBO diesel generator building structures and the mounting components securing the aforementioned equipment associated with the SBO diesel generator building against tornado wind loads, structures and components whose failure could directly prevent satisfactory accomplishment of the EDG building's intended safety function, should be included within the scope of license renewal. This issue was identified as Open Item 2.2.3.8-1.

In a letter to the staff dated September 28, 1999, the applicant reviewed its position on the SBO diesel building and mounting components described above, and has decided to include these SSCs within the scope of license renewal. On the basis of the applicant's decision to include these structures and components within the scope of license renewal, Open Item 2.2.3.8-1 is closed.

In NRC Question No. 3.3.45, the staff asked the applicant to state if any portions of the equipment and floor drainage system (EFDS) associated with the auxiliary building and EDG structures are relied upon for protection against internal or external flooding. The applicant responded that no portions of the EFDS are relied upon to protect against flooding and, therefore, no drains are within the scope of license renewal because of postulated internal or external flooding. The applicant also noted in its response that the plant drain system and liquid waste system are within the scope of license renewal for fire protection purposes and are addressed in Section 5.10 of Appendix A to the LRA. On the basis of the applicant's response, the staff agrees that there are no license renewal aspects of the EFDS that should be identified in Section 3.3E of Appendix A to the LRA.

As described above, the staff has reviewed the information presented in Section 3.3E of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff concluded that there is reasonable assurance that the applicant has appropriately identified the structural components of the auxiliary building and safety-related diesel generator building structures that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.8.2.2 Auxiliary Building and Safety-Related Diesel Generator Building Structures Subject to an Aging Management Review

The 47 structural component types within the scope of license renewal were determined by the applicant to contribute to at least one of the seven structural intended functions discussed above. One unique component type, pipe encapsulations, was evaluated in an AMR for the main steam system. The applicant identified the remaining component types for the auxiliary building and SR diesel generator building as structural components subject to an AMR, and listed these component types in Table 3.3E-2 of Appendix A to the LRA.

The staff verified that each of the remaining 46 structural component types determined by the applicant to require an aging management review are part of the auxiliary building and SR diesel generator building structures. The staff further verified that there were no additional auxiliary building and SR diesel generator building structural components that perform an intended function without moving parts or without a change in configuration or properties and that are not subject to replacement based on a qualified life or specified time period. The staff also reviewed the manner in which the applicant handled some components in the auxiliary building and SR diesel generator building structures that are common to many other plant systems and have been included by the applicant in separate sections of the LRA, which address those components as commodities for the entire plant.

Table 3.3E-2 contains the list of structural component types requiring an aging management review. This table contains 37 line items. Some of these 37 line items contained multiple component types, potentially 53 in all. The discussion in the LRA refers to 46 component types. The staff considered that the applicant should clarify how the component types are grouped so that the discussion in the text of the application and the component list in Table 3.3E-2 are consistent. During a site meeting on February 17, 1999, the applicant clarified that the discussion was in error and the components listed in Table 3.3.E-2 were the components requiring an AMR. The staff reviewed the entire list of structural component types and verified that the applicant included all the structural and system component types that constitute the auxiliary building and SR diesel generator building structures that are subject to an AMR.

The staff has reviewed the information in Section 3.3E of Appendix A to the LRA, and has determined that there is reasonable assurance that the applicant has appropriately identified the portions of the auxiliary building and SR diesel generator building structures and structural components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.9 Reactor Coolant System

In Section 4.1, "Reactor Coolant System (RCS)," of Appendix A to the LRA, the applicant described the systems with component supports at the plant site that are within the scope of license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.9.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the function of the RCS is to remove heat from the reactor core and reactor internal components and transfer it to the secondary (steam generating) system. The RCS of each unit, which is located entirely 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 are the pressurizer and quench tank. Coolant system pressure is maintained by the pressurizer, which is connected to one of the RCS loop hot legs. Because the RPV is a significant component of the RCS and because several aging mechanisms are unique to it, the RPV was separately evaluated for aging management in Section 4.2 of Appendix A to the LRA, which is evaluated in Section 3.2 of this SER.

The basic RCS functional requirements are:

- To remove heat from the reactor core and reactor internal components and transfer it to the secondary (steam) 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 information to the reactor protective system, the reactor regulating system, and the engineered safety features actuation system for the purpose of protecting the reactor core and RCS components.

The primary function of the RCPs is to force 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.

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.

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. 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.

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.

The nuclear steam supply system (NSSS) utilizes two SGs to transfer the heat generated in the RCS to the secondary (steam) system. The SG shell is constructed of carbon steel. Manways and handholes are provided for easy access to the SG internals.

The SG is a vertical U-tube heat exchanger. It 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-inch (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 have SS cladding, and the primary side of the tubesheet has nickel-chromium-iron (Ni-Cr-Fe) cladding. The vertical U-tubes are made of Ni-Cr-Fe alloy. The tube-to-tubesheet joint is welded on the primary side. Tubes that have degraded may be repaired using tube sleeves or may be removed from service by either a welded or a mechanical-type tube plug.

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.

Constant RCS makeup and letdown are 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 the safety injection system in the event that 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.

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.

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.

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 buses, that are operated from the control room. The RPV and the pressurizer each has 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 another 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 an alarm that are used for valve seat leak detection and flow indication.

The components evaluated here are 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.

The boundary between the RPV and RCS main coolant piping excludes the RPV nozzles, which are evaluated along with the RPV and control element drive mechanisms (CEDMs)/electrical system in Section 4.2 of Appendix A to the LRA.

In addition, the applicant stated that the following piping, supports, instrumentation and controls, and valves are covered in or excluded from Section 4.1 of Appendix A of the LRA.

The following piping is evaluated in or excluded from this evaluation:

- Small tubing and piping that are field run (i.e., instrumentation tubing) and that have no component designators are not evaluated in Section 4.1 of Appendix A of the LRA;
- 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 discussed in Section 4.1 of Appendix A of the LRA are evaluated in Section 3.1, and the staff's evaluation of Section 3.1 is given in Section 2.2.3.1 of this SER.

The following instrumentation and controls are covered in Section 4.1 of Appendix A of the LRA:

- All remote and local instrumentation associated with the RCS loops, the pressurizer, and the RCPs. Steam generator secondary-side instrumentation is not covered in Section 4.1 of Appendix A of the LRA;
- 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 Appendix A to the LRA;
- Automatic and manual controls for pressurizer heaters, pressurizer spray, RCPs, and the PORV and its isolation valves are evaluated in Section 4.1 of Appendix A of the LRA; and
- Power supply components for the RCPs and heaters are included up to the power supply breaker.

The following valves are evaluated in Section 4.1 of Appendix A of the LRA:

- 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 in Section 4.1 of Appendix A of the LRA; these are

- 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 evaluated in Section 4.1 of Appendix A of the LRA. The RCP and motor cooling subcomponents are included in Section 4.1 of Appendix A of the LRA out to the connection with the Component Cooling (CC) System. Included in Section 4.1 of Appendix A of the LRA, are the SG and pressurizer supports. Component supports, cables, instrument lines, and instruments not identified as RCS components in Section 4.1 of Appendix A of the LRA are generally included in the component supports commodity, cables commodity, instrument lines commodity, and fire protection AMRs.

In Appendix A to the LRA, the applicant identified the following intended functions for the RCS and system components on the basis of the requirements of 10 CFR 54.4(a)(1) and (2):

- To provide manual control of RCS pressure and pressurizer level via charging pumps during design-basis 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 protection 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 the accumulation of non-condensable gases;
- To provide differential pressure signals to the reactor protection 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 [this function also applies to station blackout (10 CFR 50.63) based on 10 CFR 54.4(a)(3)];
- To provide indication of natural circulation flow via core exit thermocouples [this function also applies to station blackout (10 CFR 50.63) based on 10 CFR 54.4(a)(3)];
- To provide reactor vessel coolant inventory level indication [this function also applies to station blackout (10 CFR 50.63) based on 10 CFR 54.4(a)(3)]; and
- To provide protection from overpressure in the RCS [this function also applies to station blackout (10 CFR 50.63) based on 10 CFR 54.4(a)(3)];

The following RCS intended functions were determined on the basis of the requirements of 10 CFR 54.4(a)(3):

- For station blackout —To detect leakage from the primary system following loss of AC power;
- For station blackout and fire protection —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 —To maintain functionality of electrical components as addressed by the environmental qualification program;

- For fire protection —To provide lube oil collection for RCP motors sized to accommodate the largest potential oil leak;

- For fire protection —To provide monitoring of essential parameters for ensuring safe shutdown in the event of a postulated severe fire;

- For fire protection —To provide RCS heat removal by realignment and operation of the shutdown cooling flowpath; and

- For fire protection —To control RCS pressure by regulating pressurizer water temperature during shutdown in the event of a postulated severe fire.

On the basis of the intended functions stated above, the applicant has identified the following structures and components of the RCS as within the scope of license renewal: piping, components (e.g., heat exchangers, pressure vessels, pumps, valves, and tanks), and instrumentation that are relied on for mitigation of design-basis events, station blackout, post-accident monitoring, environmental qualification, and fire protection. The applicant identified a total of 63 device types from within these structures and components as being within the scope of license renewal. Of these 63 device types, the applicant identified the following 16 that are subject to an AMR: piping sections CC, GC, HB, and 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; pressure vessel (only the pressurizer) (PZV); relief valve (RLV); solenoid valve (SV); and tank (TK).

The applicant also indicated that some components in the RCS that are common to many systems have been included in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Those structural supports for piping, cables, and components in the RCS that are subjected to an AMR are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA under the component supports commodity evaluation except for the SG supports and pressurizer support skirts that are evaluated as part of HX and PZV, respectively.

- Electrical cabling for components in the RCS that are subject to an AMR are evaluated for the effects of aging in Section 6.1 of Appendix A to the LRA under the electrical cables commodity evaluation.

- Instrument tubing and piping, and the associated supports, instrument valves, and fittings for components in the RCS that are subject to an AMR, and the pressure boundaries of the instrument themselves, are all evaluated for the effects of aging in Section 6.4 of Appendix A to the LRA under the instrument lines commodity evaluation.

2.2.3.9.2 Staff Evaluation

The staff reviewed Section 4.1 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the RCS components and supporting structures within scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). This was done in two steps, as described in the following two sections.

2.2.3.9.2.1 Systems, Structures, and Components Within the Scope of License Renewal

As part of the first step of its evaluation, the staff determined whether the applicant has properly identified the systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4. The staff reviewed portions of the UFSAR for the RCS, and compared the information in the UFSAR with the information in Appendix A to the LRA to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. The staff then reviewed structures and components outside the portion identified by the applicant and, as described below, asked the applicant to submit additional information and/or clarifications for a selected number of structures and components to verify that they do not have any intended functions as delineated in 10 CFR 54.4(a). The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from consideration within the scope of the rule.

After completing the initial review, (NRC letter dated September 2, 1998) the staff issued requests for additional information (RAI) regarding the RCS, and by letter dated November 2, 1998, the applicant responded to those RAIs. NRC Question No. 4.1.1 asked the applicant to explain why the component known as "spray head," which sprays colder water inside the pressurizer, was not included within the scope of license renewal.

In response, the applicant stated that the spray head inside the pressurizer does not provide a passive intended function (e.g., pressure boundary) and therefore, was not within the scope of license renewal. The staff found that the applicant's response needed further clarification as follows: On page 4.1-11 of Appendix A to the LRA, the applicant stated that for the RCS components "a detailed list of system intended functions was determined based on the requirements of 10 CFR 54.4(a)(1) and (2)," and one of those intended functions listed in Appendix A to the LRA was "to control RCS pressure by regulating water temperature in the pressurizer." Then, on page 4.1-2 of Appendix A to the LRA, the applicant described how this particular intended function is carried out: "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. 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."

On the basis of this discussion in Appendix A to the LRA, it is apparent that both of the components of the pressurizer, namely, the heater and the spray head, are relied upon to perform the intended function of RCS pressure control. The heater was included within the scope of license renewal and listed in Table 4.1-1 of Appendix A to the LRA; however, the spray head was not. The heater was dispositioned as a component not subject to an AMR because it is classified as an active component. The staff believes that the spray head is a passive component, and it is not subject to replacement based on a qualified life or specified time period. In light of this discussion, the staff requested additional clarification from the applicant concerning why the spray head should not be within the scope of license renewal, and not subject to an AMR.

In response, the applicant provided clarification during onsite meetings with the staff held on February 16–18, 1999, as documented in an NRC meeting summary dated March 19, 1999, that it has reviewed the staff's concern and verified that the pressurizer spray head has no safety-related function. The applicant further stated that the spray head and its spray function is not credited for the mitigation of any accidents addressed in the UFSAR Chapter 14 accident analyses and therefore does not meet the scoping requirements of 10 CFR 54.4(a)(1). The function of the pressurizer spray is to reduce RCS pressure under normal operating conditions. Also, its failure would not prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1). On the basis of this clarification, the staff agrees with the applicant's conclusion that the spray head need not be within the scope of license renewal.

In NRC Question No. 4.1.2, the staff asked the applicant to clarify its understanding that in Table 4.1-2 of Appendix A to the LRA, "Tank (TK)" was listed as a device type requiring an AMR; but that Figure 4.1-1 of Appendix A to the LRA shows that the quench tank No.11 is not within the scope of license renewal. In response, the applicant indicated that the device type "Tank (TK)" in Section 4.1 referred to the RCP lube oil reservoir tanks. These RCP lube oil reservoir tanks have a license renewal intended function to act as a pressure boundary for fire protection purposes. The quench tanks for CCNPP Units 1 and 2 were not in the scope of license renewal because these non-safety-related components did not serve a license renewal intended function. The staff reviewed the information and agrees with the applicant's conclusion.

Finally, in NRC Question No. 4.1.4, the staff requested the following clarification: In Table 4.2-2 in Section 4.2 of Appendix A to the LRA, footnotes were used to indicate that "not all components of a device-type were affected by the ARDM." This has been interpreted to mean that some components within the device type category are not subject to the effects of the listed plausible ARDM. Referring to Table 4.1-3 in Section 4.1.2 of Appendix A to the LRA, the applicant was asked to clarify whether any subcomponents of the components listed in the table are similarly not subject to the plausible ARDMs shown. The applicant responded that there were some components within the device-type categories listed in Table 4.1-3 of Appendix A to the LRA that were not affected by the listed ARDMs. Because of the large number of components in the RCS report, the applicant elected not to individually list those components that were not affected by the ARDMs listed in Table 4.1-3. Section 4.1 in Appendix A to the LRA for the RCS contains all of the components for each device type subject to an AMR.

As described above, the staff has reviewed the information in Section 4.1 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the RCS and the associated structures and components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.9.2.2 Reactor Coolant System Subject to Aging Management Review

In Section 4.1.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the reactor coolant system (RCS) were within the scope of the license renewal. The applicant divided those structures and components into device types not subject to an aging management review (AMR) and device types subject to an AMR [listed in Table 4.1-2 in Appendix A to the LRA]. The staff reviewed the information to verify that the applicant's grouping was correct. As described in detail below, the staff did not find any omissions or mistakes in classification by the applicant.

Of 66 device types within the scope of license renewal rule, 52 device types are electrical/ instrumentation components. The staff reviewed the device types that are electrical/ instrumentation components to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 52 components, the applicant classified the following 38 as having only active functions and, therefore, not requiring an AMR:

- analyzer element
- electric coil
- hand switch
- power lamp indicator
- level indicating controller
- 125/250-V dc motor
- pressure alarm
- pressure recorder
- temperature indicator
- temperature relay
- vibration indicator
- power supply
- miscellaneous
- relay
- analyzer indicator
- voltage/current device
- current/current device
- level controller
- level relay
- 13-kV motor
- pressure controller
- pressure relay
- temperature recorder
- heater
- vibration-indicating alarm
- position-indicating lamp
- circuit breaker
- fuse

- ammeter
- level indicator
- microprocessor
- 480-V local control station
- pressure indicator controller
- radiation indicator
- temperature transmitter
- vibration element
- vibration transmitter
- position switch

One device type, temperature element (pressure wells), is considered to be part of the pipe and is evaluated with the piping.

One device type, temperature test point (TP), is evaluated in Section 4.2 of Appendix A to the LRA, "Reactor Pressure Vessel and CEDMs/Electrical Systems."

The following eight device types are evaluated in Sections 2.2.3.32, 2.2.3.33, and 2.2.3.35, of this SER:

- level transmitter
- differential pressure transmitter
- pressure indicator
- pressure-indicator alarm
- pressure transmitter
- panel
- control/power cabling
- instrument tubing/valve

Four electrical/instrumentation components—control valve, electronically operated relief valve, MOV, and solenoid valve—evaluated in this section were classified as subject to an AMR (only pressure boundary/body). The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1) except for the category of miscellaneous.

In NRC Question No. 4.1.3, the staff asked the applicant to describe the types of components that make up the device type "Miscellaneous (XL)" listed in Table 4.1-1 of Appendix A to the LRA. This device type has been classified as only associated with active functions and, therefore, was excluded from the AMR. The applicant responded that an XL device type is a status-indicating lamp. Indication is an active function for license renewal and, therefore, XL device type components are not within scope and are not subject to an AMR. The staff finds this acceptable.

The remaining device types listed in Table 4.1-2 in Section 4.1.1.3, "Components Subject to Aging Management Review," of Appendix A to the LRA are piping and mechanical components that perform passive functions. The staff agrees with the applicant's inclusion of these devices as requiring an AMR.

The staff has reviewed the information included in Section 4.1.1.3, "Components Subject to Aging Management Review," of Appendix A to the LRA. On the basis of its review, the staff finds that there is reasonable assurance that the applicant has appropriately identified those structures and components subject to an AMR for the RCS to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.10 Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System

In Section 4.2, "Reactor Pressure Vessels and Control Elements Drive Mechanisms/Electrical System," of Appendix A to the LRA, the applicant described the structures and components of the reactor pressure vessel (RPV) and control element drive mechanisms (CEDMs), including the reactor vessel level monitoring system (RVLMS) within the scope for license renewal, and identified those systems and components that are subject to an AMR.

2.2.3.10.1 Summary of Technical Information in the LRA Concerning the RPV and CEDMs

As described in the LRA, 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. The RPV is composed of a removable head with multiple penetrations; four primary coolant inlet nozzles; two primary coolant outlet nozzles; upper, intermediate, and lower shell courses; a bottom head; and vessel supports. Each vessel is approximately 503 3/4 inches high, with an inside diameter of 172 inches, and is of an all-welded, manganese molybdenum steel plate and forging construction. 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 a cap screw); and a sliding bearing, the spherical crown of which fits into the socket, and flat side sliding surface of which rests on a base plate.

Each RPV contains the reactor vessel internals (RVIs) and associated reactor core, as discussed in Section 4.3, "Reactor Vessel Internals System," of Appendix A to the LRA. The rate of the nuclear reaction in the core 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 (that is, four tubes in a square matrix plus a central tube) are connected together at their tops by a yoke that is connected, in turn, to the CEDM extension shaft (some CEDMs have two yokes attached). The CEDMs are designed to permit rapid insertion of the CEAs into the reactor core by gravity.

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 were subsequently removed. Two of these eight CEDMs have been modified to house RVLMS probes. The remaining six were not used. 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. The CEDM pressure housings are part of the reactor coolant pressure boundary attached to the reactor vessel and are designed to meet the requirements of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code), Section III, "Nuclear Vessels."

The RVLMS housings consist of a motor housing assembly, an upper pressure housing assembly (modified from the CEDM design), a shroud, a flange adapter assembly, and a heated junction thermocouple (HJTC) probe assembly. 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.

In Appendix A to the LRA, the applicant identified the following intended functions for the RPV, the RVLMS, and system components based on the requirements of 10 CFR 54.4(a)(1) and (2):

- To vent the RCS when natural circulation flow has been disrupted or blocked by an 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)

- To provide structural support for the fuel assemblies, CEAs, and in-core instrumentation so that they maintain the configuration and flow distribution characteristics assumed in the CCNPP UFSAR Chapter 14 analyses

The following intended functions for the CEDMs and electrical system components were identified based on the requirements of 10 CFR 54.4(a)(1) and (2):

- To provide a pressure-retaining boundary for the RCS
- 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):

- For fire protection—Interrupt CEDM motor generator set output power to ensure safe shutdown in the event of a severe fire.

- For anticipated transient without scram (ATWS)—Initiate reactor trip by interrupting power to the CEDMs upon a diversified scram system signal.

- For station blackout—Trip reactor to provide for rapid shutdown of the reactor.

On the basis of the intended functions identified above, the portions of the RPV and the CEDMs/ electrical system that are identified by the applicant as being within the scope of license renewal include the following structures and components: RPVs, CEDMs, CEAs, motors, electrical panels, and associated components. The applicant identified a total of eight device types from within these structures and components as being within the scope of license renewal. Of these eight device types, the applicant identified the following three that are subject to an AMR: the RPV, CEDMs, and RVLMS test points.

The applicant also indicated that some components in the RPVs and the CEDMs/electrical system that are common to many systems have been included in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Electrical panels in the CEDMs/electrical system are evaluated for the effects of aging in the Electrical Panels Commodity Evaluation in Section 6.2, "Electrical Commodities" of Appendix A to the 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, "Environmental Qualification" of the LRA.

2.2.3.10.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the RPVs and the CEDMs/electrical system components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). This evaluation was done in two steps, as described in the following two sections.

2.2.3.10.2.1 Systems, Structures, and Components Within the Scope of License Renewal

As part of the first step in its evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4. The staff reviewed portions of the UFSAR for the RPV and the CEDMs/electrical system and compared the information in the UFSAR with the information in the LRA to identify any structures or components that the applicant did not identify as being within the scope of license renewal. The staff, using the UFSAR, then reviewed structures and components outside the scope of components identified by the applicant and, as described below, requested that the applicant provide additional information and/or clarifications for a selected number of structures and components to verify that they did not have any intended functions delineated in 10 CFR 54.4(a). The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA as another method of verifying whether any structures or components relied upon to perform the intended functions were omitted from the scope of license renewal.

After completing the initial review of components not included within the scope of license renewal, the staff issued RAIs regarding the RPVs and the CEDMs/electrical system (NRC letter dated August 26, 1998), and by letter dated November 19, 1998, the applicant responded to the RAIs. Specifically, the staff noted in NRC Question No. 4.2.1 that Figure 4-2 (Revision 18) in Chapter 4 of the CCNPP UFSAR for Units 1 and 2 showed a component attached to the closure head of the RPV, which was called a "lifting lug," and asked the applicant to indicate whether the lifting lugs were within the scope of license renewal. In response, the applicant stated that the lifting lugs were considered to be an integral part of the RPV closure head plates, were included within the scope of the license renewal review, and were evaluated for aging management as described in Section 4.2.2 of Appendix A to the LRA. In NRC Question No. 4.2.2, the staff noted that Figure 4-2 (Revision 18) in Chapter 4 of the CCNPP UFSAR showed that the closure head insulation is attached to the closure head of the RPV and requested that the applicant describe the functions of the closure head insulation and explain whether it is required to support one of the functions listed in 10 CFR 54.4(a). The applicant responded that this insulation performs none of the intended functions listed in Section 4.2.1.1 on page 4.2-5 of Appendix A to the LRA and, therefore, was not within the scope of license renewal. The staff concurred with the assessment. NRC Question No. 4.2.3 asked the applicant to clarify whether the component identified in comment (d) of Table 4.2-2 of Section 4.2.1 of Appendix A to the LRA as a "core stop lug" was the same component labeled as the "core support lug" in Figure 4-2 (Revision 18), in Chapter 4 of the CCNPP UFSAR. If these components are not the same, the staff requested that the applicant describe the functions of the core support lug and explain whether it is required to support one of the functions listed in 10 CFR 54.4(a). In its response, the applicant indicated that these components are the same (they just have a different nomenclature) and, therefore, they are within the scope of license renewal. On the basis of the staff's review of supporting information in the CCNPP UFSAR and the applicant's response to the RAI, the staff has found no omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant has appropriately identified those portions of the RPV and the CEDMs/electrical system and their associated (supporting) structures and components that are within the scope of license renewal in accordance with 10 CFR 54.4.

2.2.3.10.2.2 Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System Subject to an Aging Management Review

In Section 4.2.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the electrical system were within the scope of the license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 4.2-1 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct. As described in detail below, the staff finds no omissions or mistakes in classification by the applicant. Therefore, the staff finds that there is reasonable assurance that the applicant has identified the structures and components subject to an AMR for the RPVs and CEDMs/electrical system.

Of eight device types within the scope of the license renewal rule, six device types are electrical/ instrumentation components. The staff reviewed the device types that are electrical/ instrumentation components to verify that the applicant did not omit any electrical/

instrumentation components that should be subject to an AMR. Of the six components, the applicant classified the following four as having only active functions and, therefore, not requiring an AMR:

- 480-V AC motors
- control element assemblies
- 125/250-V dc motors
- load contactors

Two device types, control/power cabling and electrical panels, are evaluated in Section 2.2.3.32, "Cables," and Section 2.2.3.33, "Electrical Commodities," of this SER. No other electrical/instrumentation components were determined to be subject to an AMR. The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

Table 4.2-1 indicates that the RPV, the CEDM, and the reactor vessel level monitoring system (RVLMS) test point (TP) were determined to be device types that require an AMR. The applicant indicated that the passive intended function of the RPV and CEDMs is to maintain the pressure boundary of the system. In addition, the applicant indicated that another passive function of the RPV is to provide structural support for the fuel assemblies, control element assemblies (CEAs), and incore instrumentation (ICI). The applicant further divided the RPV into subcomponent parts to identify additional passive intended functions. These additional passive intended functions are listed in the LRA. The staff agrees with the applicant's inclusion of the devices listed in Table 4.2-1 as requiring an AMR.

The staff has reviewed the information in Section 4.2.1.3, "Components Subject to Aging Management Review," of Appendix A to the LRA. On the basis of its review, the staff finds that there is reasonable assurance that the applicant has appropriately identified those structures and components subject to an AMR for the RPVs and CEDMs to meet the requirements of 10 CFR 54.21(a)(1).

2.2.3.11 Reactor Vessel Internals System

In Section 4.3, "Reactor Vessel Internals System," of Appendix A to the LRA, the applicant described the structures and components of the reactor vessel internals (RVI) system at the plant site that are within the scope for license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.11.1 Summary of Technical Information in Application

As described in Appendix A to the LRA, the RVI includes 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 contains reactor component handling equipment.

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), 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.

The RVIs 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.

In Section 3.3.3 of the UFSAR, the applicant describes 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 RVIs are constructed of Type 304 SS and nickel-chromium-iron (Ni-Cr-Fe) alloy steels. These materials were chosen during the design phase because they had shown satisfactory performance in operating reactor plants.

The major support member of the RVI is the core support assembly, which consists of the CSB, the lower core support structure, and the core shroud. 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 Core shroud, 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. 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.

In the reactor core, the fuel assemblies have functions during design-basis events that place the assemblies within the scope of license renewal. However, the assemblies are replaced at regular intervals dependent on the fuel cycle of the plant. Since the assemblies are short-lived components, their aging is not discussed in Appendix A to the LRA. The CEAs in the core are discussed with the control element drive mechanisms and electrical system in Section 4.2 of Appendix A to the LRA.

The reactor vessel head lifting rig is discussed with the fuel handling equipment and other heavy load handling cranes in Section 3.2 of Appendix A to the LRA. The RVI lifting rigs and the surveillance capsule retrieval tool are not installed components and are not within the scope of license renewal.

In Appendix A to the LRA, the applicant identified the following intended function for the RVI and system components according to the requirements in 10 CFR 54.4(a)(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.

On the basis of the intended function noted above, the portions of the RVI that are identified by the applicant as within the scope of license renewal and as subject to an AMR include the following 17 device types: CEA shroud and bolts (CEASB), CEA shroud extension shaft guides (ESGs), Core shroud, core shroud tie rod (CSTR) and bolts, CSB, core support barrel alignment (CSBA) key, core support barrel snubber and snubber bolts, core support columns (CSCs), CSP, flow baffle, fuel alignment pins, fuel alignment plate/guide lug insert, HDR, ICI thimble support plate (ITSP), ICI thimbles, lower support structure beam assembly (LSSBA), and upper guide structure support plate (UGSP).

Not all device types of the RVIs shown above are evaluated in Section 4.3 of Appendix A to the LRA. These device types are excluded from Section 4.3 for the following reasons:

- The CSB 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. Because of this mating-part relationship, the snubber and the snubber bolts are evaluated along with the lugs in Section 4.2 rather than in Section 4.3 of Appendix A to the LRA.

- The flow baffle is a structure inside 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 along with other vessel components in the reactor vessel/control element drive mechanism system in Section 4.2 of Appendix A to the LRA.

- 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 Appendix A to the LRA along with reactor pressure vessel components that have the same function.

2.2.3.11.2 Staff Evaluation

The staff reviewed Section 4.3 of Appendix A to the LRA to determine whether there is reasonable assurance that the RVI components and supporting structures subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished in two steps, as described in the following two subsections.

2.2.3.11.2.1 Systems, Structures, and Components Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR for the RVIs, and compared the information in the UFSAR with the information in Appendix A to the LRA to determine if there were any additional portions of the RVI and other components that the applicant should have identified as within the scope of license renewal. The staff then reviewed structures and components outside the applicant-identified portion, and as described below, asked the applicant to submit additional information and/or clarifications for a selected number of structures and components to verify that they do not have any intended functions as delineated in 10 CFR 54.4(a). The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from consideration within the scope of the rule.

After completing the initial review, by letter dated September 3, 1998, the staff issued requests for additional information (RAIs) regarding the RVIs, and by letter dated November 19, 1998, the applicant responded. Figure 3.3-6 (Revision 21) of the CCNPP UFSAR shows the fuel assembly hold-down (FAHD) structure. One of the intended functions of the FAHD structure is to prevent fuel assemblies from being lifted out of position under accident loading conditions. NRC Question No. 4.3.1 asked the applicant to clarify whether the FAHD structure (particularly the spring) was within scope and subject to an AMR; the spring may lose its required force at an extended age. In response, the applicant stated that Figure 3.3-6, "Fuel Assembly Hold Down," illustrates the relationship between the fuel alignment plate (which is part of the RVIs) and an individual fuel assembly. Except for the fuel alignment plate, all the components shown on Figure 3.3-6, including the upper end fitting, spring, spider, and upper end fitting posts, are part of the fuel assembly. Since the upper end fitting components of a fuel assembly are discarded with that assembly and since fuel assemblies are replaced based on a fixed number of fuel cycles fuel assemblies (including the upper end fitting components) are considered short-lived and are not subject to an AMR.

Figure 3.3-14 (Revision 21) of the CCNPP UFSAR shows the upper guide structure (UGS) assembly. NRC Question No. 4.3.2 asked the applicant to describe the functions of the component identified in the UFSAR as the expansion compensating ring, and to indicate if its intended functions would meet the definition of intended function given in 10 CFR 54.4(a). The applicant responded by noting that the expansion compensating ring, called the hold-down ring (HDR) in Appendix A to the LRA, states the following intended function: "provide structural support for the fuel assemblies, CEAs, and ICI so that they maintain the configuration and flow distribution characteristics assumed in UFSAR Chapter 14 analyses." This intended function conforms to the definition of "intended function" in 10 CFR 54.4(a). All RVI components that perform this function were subject to an AMR.

In Section 4.1.3.6 (Revision 18) of the CCNPP UFSAR, the applicant indicated that vents were added to the reactor vessel and to the pressurizer head in response to the Three Mile Island "Lessons Learned Report" (NUREG-0737, Item II.B.1). One of the intended functions of the vents is to ensure core cooling during a loss-of-coolant accident. NRC Question No. 4.3.3 asked the applicant to clarify if this vent system was subject to an AMR, and if it was, the question also asked for a cross-reference to where this system is addressed in Appendix A to the LRA. The applicant stated in its response that the reactor vessel vent system was within scope and subject to an AMR. The nozzles were evaluated as part of the reactor vessel heads in Section 4.2 of Appendix A to the LRA. The vent system includes valves, piping, and tubing. The piping and associated valves were evaluated along with the reactor coolant system (RCS) in Section 4.1 of Appendix A to the LRA. Tubing and associated valves were evaluated in the instrument lines commodity evaluation in Section 6.4 of Appendix A to the LRA. The pressurizer vent system was also subject to an AMR. As noted in Section 4.1.3.6 of the CCNPP UFSAR, the pressurizer vent line valves are installed in a line that was added as another branch off the pressurizer vapor sample line. Part of this vent system was evaluated along with the nuclear steam supply sampling system in Section 5.13 of Appendix A to the LRA. The other part was evaluated with the RCS in Section 4.1 of Appendix A to the LRA.

As described above, the staff has reviewed the information in Section 4.3 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff concludes that the applicant has appropriately identified those portions of the RVIs and the associated (supporting) structures and components that fall within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4.

2.2.3.11.2.2 Reactor Vessel Internals System Subject to an Aging Management Review

According to their function, the RVI structures are determined to perform their functions without moving parts or without a change in configuration or properties. Section 4.3 of Appendix A to the LRA only evaluates the RVI structures component device types that are subject to age-related degradation mechanisms (ARDMs) that require their inclusion in the AMR program. In the reactor core, the fuel assemblies have functions during design-basis events that make the assemblies fall within the scope of license renewal. However, the assemblies are replaced at regular intervals based on the fuel cycle of the plant and, therefore, the fuel assemblies are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(ii).

The staff has reviewed the information in Section 4.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff RAIs. On the basis of a review of selected RVI structures and components, the staff finds that there is reasonable assurance that the applicant has appropriately identified the RVI structures and components subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.12 Auxiliary Feedwater System

In Section 5.1, "Auxiliary Feedwater System," of Appendix A to the LRA, the applicant described the structures and components of the AFW system at the plant site that are within the scope for license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.12.1 Summary of AFW Technical Information in the Application

As described in the LRA, the AFW system is designed to provide emergency water from the 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 feedwater pumps are inoperative. The AFW system has three pumps per unit— two turbine-driven pumps and one motor-driven pump. The turbine-driven pumps can be used to perform plant cooldown to 300 °F; the motor-driven pump is reserved for emergency use only.

Upon automatic initiation, one turbine-driven AFW pump and the motor-driven AFW pump automatically start. The pumps take suction from the 300,000 gallon CST, which provides sufficient water for decay heat removal and cooldown for both units. The system also contains the following major components: piping, turbine isolation and governor valves, flow control valves, check valves, flow elements, and instrumentation and controls sufficient to safely operate the system. Part of the instrumentation and controls for the AFW system is the auxiliary feedwater actuation system (AFAS). The AFAS starts the AFW pumps upon detection of a very low level of steam in either steam generator and blocks AFW flow to a ruptured steam generator.

In the LRA, the applicant identified the following intended functions for the AFW system based on 10 CFR 54.4(a)(1) and (2):

- Provide AFW to the steam generators (SGs) for decay heat removal.
- Maintain the pressure boundary of the system.
- Isolate the AFW to the SG.
- Maintain electrical continuity and/or provide protection of the electrical system.
- Provide circuit protection for the SG pressure signal being sent from the feedwater system to the engineered safety features actuation system and the reactor protective system.

- Provide seismic integrity and/or protection of safety-related components.

- Restrict flow to ensure adequate recirculation flow for pump cooling, and to limit recirculation flow so that adequate AFW flow is provided to the SGs.

The applicant also determined that the following were intended functions of the AFW system based on the requirements of 10 CFR 54.4(a)(3):

- For environmental qualification (EQ)—Maintain functionality of electrical components as addressed by the EQ program, and provide information used to assess the condition of the plant and its environs during and following an accident.

- For anticipated transient without scram (ATWS)—Provide AFAS start signal on low steam generator water level condition.

- For station blackout (SBO)—Provide AFW to steam generators for decay heat removal and provide condensate inventory.

- For fire protection—Monitor essential AFW parameters to ensure safe shutdown in the event of a postulated fire. 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 fire.

On the basis of the intended functions listed above, the portions of the AFW system that are identified by the applicant as within the scope of license renewal are the following equipment types: piping; components (i.e., pumps, valves, and tanks); supports; instrumentation; and cables that are required for mitigation of design basis-events, for EQ, for SBO, for ATWS, and for safe shutdown following a fire. The applicant identified a total of 47 device types from within these AFW equipment types as being within the scope of license renewal because they have at least one intended function. Of these 47 device types, the applicant identified the following 19 that are subject to an AMR: 7 piping types, 6 valves types (check, flow control, pressure control, governor, solenoid, and hand valve), flow element, flow orifice, current/pneumatic device, pump, turbine, and tank. The applicant further indicated that maintenance of the pressure boundary for the liquid in the AFW system, restricting flow for pump cooling, and ensuring adequate flow to the SGs are the only passive intended functions associated with the AFW system that are not addressed in one of the commodity evaluations of the LRA.

The applicant also indicated that some components in the AFW system that are common to many systems have been evaluated in the separate commodity reports that address those components for the entire plant. Therefore, they were not evaluated in the individual system sections. These components include the following:

- Structural supports for piping, cables, and components that are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;
- Electrical control and power cabling, which is evaluated in Section 6.1 of Appendix A to the LRA;
- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.12.2 Staff Evaluation

The staff reviewed Section 5.1 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the AFW system components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued requests for additional information (RAIs) regarding the AFW system (NRC letter dated August 21, 1998), and the applicant responded to those RAIs by letter dated November 2, 1998.

2.2.3.12.2.1 Auxiliary Feedwater System Structures and Components Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed the information submitted by the applicant in the LRA and portions of the UFSAR, including flow diagrams for Unit 1 and Unit 2 AFW systems, to look for portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. Essentially all portions of the AFW system were determined to perform at least one intended function and, therefore, essentially all portions and components of the AFW system are within the scope of license renewal and are identified as such by the applicant either in Section 5.1 or in other sections of Appendix A to the LRA. The staff reviewed the few remaining components of the AFW system to verify that they have no intended functions. The staff also reviewed portions of the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structures or components having an intended function were omitted from within the scope of the rule.

In the LRA, the applicant submitted a simplified diagram (Figure 5.1-1) of the AFW system and a list of device types to identify the portion of the AFW system that is within the scope of license renewal and to identify the system interfaces. Figure 5.1-1 was representative of the system, but did not contain many of the details necessary to determine the system interfaces or the components within the scope of license renewal. The staff used the flow diagram in the UFSAR to identify components that did not appear on the simplified diagram, such as the local temperature indicators on the AFW turbines, steam piping drains, steam stop and control valves, and AFW turbine exhaust piping. To help ensure that all components within the scope of license renewal appeared on the list of device types, that those portions of the AFW system identified as not within the scope of license renewal did not have any intended functions that may require an AMR, and to ensure that all interfacing systems and components within the scope of license renewal were identified, the staff asked the applicant for more detailed information.

In response to NRC Question Nos. 5.1.1 and 5.1.3 regarding components within the scope of license renewal, the applicant submitted information justifying the omission of the local turbine temperature indicators from the list of device types within the scope of license renewal, because these indicators provide local indication of turbine oil reservoir temperature but do not perform an intended function as defined in 10 CFR 54.4(a)(1), (2), or (3). For the steam drain piping, the applicant clarified that this piping was within the scope of license renewal and was evaluated in another section of the LRA. The applicant provided a cross-reference to where the information could be found. The applicant also clarified that the steam stop and control valves were within the scope of license renewal and evaluated in Section 5.1.

Exhaust piping from the AFW turbines to the roof exhausts was also omitted from the list of components within the scope of license renewal. The applicant explained in its response to NRC Question No. 5.1.1 that this piping is non-safety-related with no intended functions for license renewal. The staff reviewed the applicant's response and concluded that the applicant had not submitted sufficient information to determine whether the piping was outside the scope of license renewal. On February 18, 1999, the staff met with the applicant to discuss the AFW turbine exhaust piping. The applicant presented an evaluation of the failure of the exhaust piping and its effects on the safety-related equipment in the room. The staff reviewed this evaluation and accepted that the failure of the exhaust piping would not cause the failure of any safety-related equipment to perform its intended function. As a result of this evaluation, the staff concludes that the piping is not required to be within the scope of license renewal based on 10 CFR 54.4. The staff documented the results of this meeting in a meeting summary dated March 19, 1999.

In response to NRC Question No. 5.1.2 regarding system interfacing components for the main steam and auxiliary steam systems, the applicant clarified the interfacing boundaries for the AFW system so that the staff was able to conclude that any interfacing components in the main steam and auxiliary steam system were included in the list of components within the scope of license renewal for the AFW system, or were included in the list of components within the scope of license renewal for the interfacing system.

As described above, the staff has reviewed the information in Section 5.1 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified those AFW structures and components within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.12.2.2 Auxiliary Feedwater System Subject to an Aging Management Review

In Section 5.1.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the AFW are within the scope of license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.1-1 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct. The staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components for the AFW system subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Of the 50 device types within the scope of the license renewal rule, 35 device types are electrical/instrumentation components. The staff reviewed the device types that are electrical/ instrumentation components to verify that the applicant did not omit electrical/instrumentation components that should be subject to an AMR. Of the 35 components, the applicant classified the following 21 as having only active functions and therefore not requiring an AMR:

- 2/4 logic component
- flow indicator
- flow component (relay)
- current/current component
- power lamp indicator
- 125/250-V dc motor
- power supply
- voltage/current component
- flow indicator controller
- hand controller
- current/voltage component
- level indicator alarm
- vacuum breaker valve
- position indicating lamp
- coil
- fuse
- hand switch
- ammeter
- 4-kV motor
- relay
- position switch

The staff agreed that these 21 device types were active and therefore not subject to an AMR. The applicant has used the following AFW system functions to determine whether or not components perform their functions with moving parts or a change in configuration or properties:

- 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 safety-related components; and
- Provide flow restriction to ensure adequate recirculation flow for pump cooling, and to limit recirculation flow so that adequate AFW flow is provided to the steam generators.

The staff finds that application of these criteria will not result in components that should be subject to an AMR being excluded from an AMR.

Instrument line manual drain, equalization, and isolation valves in the AFW system that are subject to an AMR are evaluated for the effects of aging in Section 2.2.3.35, "Instrument Line," or Section 2.2.3.33, "Electrical Commodities," of this SER.

Hand valves and piping, which are relied upon for safe shutdown in the event of a fire and are classified as non-safety-related, are discussed for the effects of aging in the fire protection evaluation in Section 5.10 of Appendix A to the LRA. All safety-related valves and piping are subject to an AMR. A total of 24 current/pneumatic devices are within the scope of license renewal. Only 8 of these devices are subject to an AMR. The other 16 are not subject to an AMR because they are either included in a replacement program or they have only active intended functions.

One device type, flow transmitter, consists of 16 flow transmitters that are within the scope of license renewal. Four of the transmitters are subject to replacement based on a qualified life and do not require an AMR. Twelve transmitters are evaluated in Section 2.2.3.35, "Instrument Line," of this SER.

The following eight device types are evaluated in Sections 2.2.3.32, "Cables," 2.2.3.33, "Electrical Commodities," or 2.2.3.35, "Instrument Line," of this SER:

- level indicator
- pressure switch
- control/power cabling
- level transmitter
- pressure transmitter
- instrument tubing/valve
- pressure indicator
- panel

The following five electrical/instrumentation components evaluated in this section were classified as subject to an AMR (only pressure boundary/body):

- control valve
- control valve operator
- flow element
- pressure control valve
- current pneumatic device
- solenoid valve

The remaining device types listed in Table 5.1-1, including the piping, check valve, hand valve, pump/drive assembly, relief valve, and tank, were reviewed and verified that the applicant did not omit components that should be subject to an AMR.

The staff has reviewed the information in Section 5.1 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.13 Chemical and Volume Control System

In Section 5.2, "Chemical and Volume Control System (CVCS)," of Appendix A to the LRA, the applicant described the systems with component supports at the plant site that are within the scope for license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.13.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the purpose of the CVCS is to perform the following functions:

- 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 before 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.

The CVCS is composed of two subsystems: letdown and charging, and makeup. The letdown and charging subsystem's major components are letdown stop valves, regenerative heat exchanger, excess flow check valves, letdown flow control valves, letdown heat exchangers, letdown backpressure control valves, purification filters, ion exchangers, volume control tank, charging pumps, boronmeter, process radiation monitor, and reactor coolant pump bleedoff containment isolation valves (to the volume control tank). The makeup subsystem's major components are 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.

In Appendix A to the LRA, the applicant identified the following intended functions for the CVCS and its components based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- To provide containment isolation of the CVCS during a loss-of-coolant accident (LOCA) (a function also applicable to station blackout (10 CFR 50.63), based on 10 CFR 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 (a function also applicable to pressurized thermal shock (10 CFR 50.61) and fire protection (10 CFR 50.48), based on 10 CFR 54.4(a)(3));
- To provide radiological release control by isolating the RCS letdown line during a LOCA;
- To provide the pressure boundary of the CVCS (liquid and/or gas);
- To provide long-term core flush via pressurizer auxiliary spray (also applicable to pressurized thermal shock (10 CFR 50.61), based on 10 CFR 54.4(a)(3));
- To maintain electrical continuity and/or protect the electrical system;
- To maintain mechanical operability and/or protect the mechanical system;
- To restrict flow to a specified value in support of a design-basis event response; and,
- To maintain safety-related components seismic integrity and/or protect them.

The following CVCS intended functions were determined based on the requirements of 10 CFR 54.4(a)(3):

- 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 severe fire;
- For environmental qualification (10 CFR 50.49)—to maintain functionality of electrical components as prescribed by the environmental qualification program; and
- For station blackout (10 CFR 50.63)—to provide RCS isolation to maintain RCS inventory during a station blackout.

On the basis of the intended functions listed above, the portions of the CVCS that are within the scope of license renewal include all components (electrical, mechanical, and instrument) and their supports along the following system flowpaths:

- 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 bleedoff 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 pump header and to the makeup stop valve;
- From the boric acid storage tanks through the gravity feed valves to the charging pump header; and
- From the RCS interface at the letdown stop valves through the regenerative heat exchangers 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 component cooling (CC) system, although the piping between the letdown flow control valves and the letdown heat exchanger is not within the scope of license renewal.

All piping within the scope of license renewal for the CVCS is identified as being within the safety-related pressure boundary, and each piece of equipment within this boundary is considered a safety-related pressure boundary component.

On the basis of the intended functions identified above, 53 device types (not including the two device types evaluated in commodity reports, described below) were listed from the portions of the CVCS that are noted by the applicant as within the scope of license renewal. Of these 53 device types, the applicant identified 25 that are subject to an AMR. Of these 25 device types, 17 are addressed in Section 5.2 of Appendix A to the LRA: piping sections CC and HC, accumulator (ACC), basket strainer (BS), check valve (CKV), control valve (CV), flow element (FE), flow orifice (FO), hand valve (HV), heat exchanger (HX), motor-operated valve (MOV), pressure control valve (PCV), pump/driver assembly (PUMP), relief valve (RLV), solenoid valve (SV), temperature element (TE), and tank (TK). The remaining 8 device types are flow transmitter (FT), level indicator alarm (LIA), level switch (LS), pressure differential indicator (PDI), pressure indicator (PI), pressure switch (PS), and pressure transmitter (PT) are evaluated in the Instrument Lines Commodity Evaluation in Section 6.4 of Appendix A to the LRA, and panel (PNL) is evaluated in the Electrical Panels Commodity Evaluation in Section 6.2 of Appendix A to the LRA.

The applicant also indicated that some components in the CVCS that are common to many systems have been included in the separate commodity reports addressing those components for the entire plant. Therefore, these components are not included among the 53 CVCS device types discussed above. They are evaluated as follows:

- Structural supports for piping, cables and components in the CVCS that are within scope and are subject to an AMR are evaluated for the effects of aging in the Component Supports Commodity Evaluation in Section 3.1 of Appendix A to the LRA.
- Electrical cabling for components in the CVCS that are subject to an AMR are evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of Appendix A to the LRA.
- 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 an AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of Appendix A to the LRA.

2.2.3.13.2 Staff Evaluation

The staff reviewed Section 5.2 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the CVCS components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4.and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished in two steps, as described in the following two subsections.

2.2.3.13.2.1 Chemical and Volume Control System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff determined whether the applicant has properly identified the systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4. The staff reviewed portions of the UFSAR for the CVCS, and compared the information in the UFSAR with the information in Appendix A to the LRA to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. The staff then reviewed structures and components outside the portion identified by the applicant, as described below, asked the applicant to provide additional information or clarifications for selected structures and components to verify that they do not have any of the intended functions listed in 10 CFR 54.4(a). The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from consideration within the scope of the rule.

After completing the initial review, by letter dated September 3, 1998, the staff issued requests for additional information regarding the CVCS, and by letter dated November 4, 1998, the applicant provided responses to NRC questions. Page 9.1-31 (Rev. 21) of the CCNPP UFSAR indicates that boric acid solution is stored in heated and insulated tanks and is piped in heat-traced and insulated lines to preclude precipitation of the boric acid. NRC question No. 5.2.8 requested that the applicant specify whether the storage tank and pipe insulation material within the CVCS was within the scope of license renewal and subject to an AMR, and if not, to justify excluding these components from the renewal scope. In response, the applicant stated that the insulation performs none of the intended functions listed in Appendix A to the LRA and, as such is not within the scope of license renewal. The staff concludes that, even if the CVCS relied on the insulation to perform any accident mitigation functions, there are no plausible aging effects for the insulation that would warrant an aging management program.

As described above, the staff has reviewed the information in Section 5.2 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portion of the CVCS and associated structures and components within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4.

2.2.3.13.2.2 Chemical and Volume Control System Subject to an Aging Management Review

In Section 5.2.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the chemical and volume control system (CVCS) are within the scope of the rule. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.2-2 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the applicant's grouping was correct.

Of the 55 device types within the scope of the license renewal rule, 42 are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit electrical/instrumentation components that should be subject to an AMR. Of the 42 components, The applicant classified the following 27 as having only active functions and, therefore, not requiring an AMR:

- coil
- disconnect switch/link
- flow device (relay)
- current/pneumatic device

- level controller
- 480-V motor
- pressure controller
- temperature indicating controller
- control switch
- flow indicator alarm
- hand indicator controller
- ammeter
- level indicating transmitter
- 125/250-V dc motor
- heat tracing controller
- temperature switch
- control valve operator
- fuse
- hand switch
- power lamp indicator
- level device (relay)
- MOV operator
- relay
- electric heater
- miscellaneous indicating lamps
- position indicating lamp
- position switch

The following 10 device types are evaluated under Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrumentation Lines," of this SER:

- flow transmitter
- pressure differential indicator
- pressure switch
- instrument tubing/valves
- level indicator alarm
- pressure indicator
- pressure transmitter
- level switch
- panel
- control/power cabling

The following five electrical/instrumentation components evaluated in this section were classified as subject to an AMR (only pressure boundary/body). The staff considers the applicant's classification consistent with 10 CFR 54.21(a)(1):

- control valve
- solenoid valve
- flow element
- temperature element
- MOV

Thirteen device types within the scope of license renewal are mechanical components or structural supports. The structural supports for piping, cables and components are evaluated in Section 2.2.3.1, "Component Supports," of this SER.

The remaining 12 device types listed in Table 5.2-2 are piping and mechanical components that perform passive functions. The staff agrees with the applicant's inclusion of these devices as requiring an AMR.

The staff reviewed the information in Section 5.2.1.3, "Components Subject to Aging Management Review," of Appendix A to the LRA. On the basis of its review, the staff finds that there is reasonable assurance that the applicant has appropriately identified those structures and components subject to an AMR for the CVCS to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.14 Component Cooling System

In Section 5.3, "Component Cooling (CC) System," of Appendix A to the LRA, the applicant described the CC system and the CC components that are within the scope for license renewal, and identified which of those components are subject to an AMR.

2.2.3.14.1 Summary of Technical Information in the Application

As described in the LRA, the CC system is designed to remove heat from various safety-related and non-safety-related plant systems. The saltwater (SW) system (Section 5.16, "Safety Injection System," of Appendix A to the LRA) supplies the cooling medium for the CC heat exchangers and discharges the heated water to the ultimate heat sink. The CC system is required to operate during normal operation, plant shutdown, and post-accident conditions. The CC system for each unit consists of three motor-driven pumps, two heat exchangers, a head tank, a chemical additive tank, and associated valves, piping, instrumentation, and controls.

In Appendix A to the LRA, the applicant identified the following intended functions for the CC system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide containment integrity during a design-basis event.
- Provide support as a vital auxiliary for containment spray process fluid cooling (via shutdown cooling heat exchanger) plus high- and low-pressure safety-injection pump cooling.
- Provide seismic integrity and protect safety-related components.
- Maintain electrical continuity and protect the electrical system.
- Maintain the pressure boundary of the system.

The applicant also determined that the following were intended functions of the CC system based on the requirements of 10 CFR 54.4(a)(3):

- For post-accident monitoring— Provide information used to assess the condition of the plant and its environs during and following an accident.
- For equipment qualification—Maintain functionality of electrical components as required by 10 CFR 50.49.

- For fire protection— Provide a heat sink for essential shutdown cooling loads to ensure safe shutdown in the event of a fire.
- For fire protection— Provide alternate heat sink via the unaffected unit for essential shutdown cooling loads in the event of a fire in the CC room.

On the basis of the intended functions listed above, the portions of the CC system that are identified by the applicant as within the scope of license renewal include the following equipment types: piping; components (i.e., heat exchangers, pumps, valves, and tanks); supports; instrumentation; and cables that are required for mitigation of design-basis events, for EQ, and for safe shutdown following a fire. The applicant identified a total of 36 device types from within these CC equipment types as being within the scope of license renewal. Of these 36 device types, the applicant noted the following 13 that are subject to an AMR: piping; six valve types (automatic vent, check, control, relief, solenoid, and hand valve); pump/driver assembly; radiation element; temperature element; temperature indicator; temperature indicating controller, and tank. The applicant further indicated that maintenance of the pressure boundary for the liquid in the CC system is the only passive intended function associated with the CC system that is not addressed in one of the commodity evaluations of the LRA. Additionally, the CC heat exchanger is evaluated in the salt water system section (Section 5.16) of Appendix A to the LRA and Section 2.2.3.29 of this SER.

The applicant also indicated that some components in the CC system that are common to many systems have been included in the separate commodity reports, which address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1, "Component Supports," of Appendix A to the LRA;
- Electrical control and power cabling that is evaluated in Section 6.1, "Cables," of Appendix A to the LRA; and
- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4, "Instrument Lines," of Appendix A to the LRA.

2.2.3.14.2 Staff Evaluation

The staff reviewed Section 5.3 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the CC system components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the CC system (NRC letter to BGE dated August 11, 1998), and by letters dated November 2 and 12, 1998, the applicant responded to those RAIs.

2.2.3.14.2.1 Component Cooling System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including the system flow diagrams for the CC system, to determine if there were any portions of the system piping and other components that the applicant did not identify as within the scope of license renewal. In the LRA, the applicant identified a number of license renewal interface boundaries within the CC system. On one side of the interface boundary, the system piping and other components are within the scope of license renewal; on the other side of the interface boundary, the piping and other components are outside the scope of license renewal. A license renewal interface boundary usually exists within the system at a point at which non-safety-related portions of the system piping interface with safety-related portions because the non-safety-related portions do not perform any intended functions and the safety-related portions perform at least one intended function. Appropriate isolation capability, which is part of the existing licensing and design basis for the system, is provided at each of the license renewal interfaces. Isolation capability was not reevaluated for license renewal because each of the interfaces is part of the current licensing basis and was previously found acceptable by the staff. However, the staff did verify that the components providing this isolation capability were within the scope of license renewal. Interface boundaries also exist where the CC system interfaces with other systems through various components such as heat exchangers, equipment cooling coils, or head tank fill piping. The staff reviewed all the identified license renewal interface boundaries within the CC system in addition to all the identified interface boundaries with other systems, structures, and components. The staff also reviewed the system flow diagrams to verify that there were no significant interface boundaries that were not identified by the applicant in the LRA. If the portions of the CC system beyond the license renewal interface boundary (i.e., portions of the system that are not within the scope of license renewal) were verified by the staff to have no intended functions, then the components within those portions of the system were also deemed to have no intended function and were eliminated from further consideration. The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structures and components having intended functions might have been omitted from consideration within the scope of license renewal.

Because of its function as a cooling water supply, the CC system interfaces with 20 other systems, 13 of which are within the scope of license renewal. In Appendix A to the LRA, the applicant indicated that the CC system at the interfaces may or may not be within the scope of license renewal. To help ensure that those portions of the CC system identified as outside the scope of license renewal at these interfaces did not perform any intended functions and, therefore, did not have any components subject to an AMR, the staff requested additional information from the applicant based on the information in the UFSAR and the LRA. In response to NRC Question No. 5.3.1, regarding the system interfaces, the applicant described the interfaces for the seven interfacing systems that were not within the scope of license renewal. Of the seven interfaces, five were adequately separated by normally closed or automatically closing valves (or check valves at some component outlets) that were accepted as adequate separation between safety-related and non-safety-related portions of the system as part of the licensing and design basis. As approved in the current licensing basis, these valves provide acceptable separation between portions of the CC system that are within the scope of license renewal and those portions that are not. Of the other two interfaces, one is the demineralized water makeup line to the head tank, whose failure cannot affect any intended function, and the other is at the gas analyzer sample cooler where the CC system is within the scope of license renewal because the cooler is continuously supplied with CC flow from either Unit 1 or Unit 2. On the basis of the applicant's response and the supporting information in the UFSAR, the staff concludes that those portions of the CC system that are identified as outside the scope of license renewal do not perform any intended functions that would have designated these portions of the system to be within the scope of license renewal.

As described above, the staff reviewed the information presented in Section 5.3 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the CC system and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.14.2.2 Component Cooling System Subject to an Aging Management Review

In Section 5.3.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the component cooling (CC) system were within the scope of license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.3-2 in Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct.

Of the 37 device types within the scope of the license renewal rule, 29 device types are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit electrical/instrumentation components that should be subject to an AMR. Of the 29 components, the applicant classified the following 15 as having only active functions and, therefore, not requiring an AMR:

- coil
- fuse
- power light indicator
- pressure indicator
- power supply
- disconnect link switch
- hand switch
- 480-V ac motor
- relay
- position indicating lamp
- voltage current device
- ammeter

- 125/250-V dc motor
- temperature indicating alarm
- position switch

One device type, pressure transmitter, is subject to replacement on the basis of a qualified life or specified time period and does not require an AMR.

The following seven device types are evaluated under Sections 2.2.3.32, "Cables"; 2.2.3.33, "Electrical Components"; or 2.2.3.35, "Instrument Lines," of this SER:

- level switch
- pressure switch
- panel
- level transmitter
- control/power cabling
- differential pressure Indicating switch
- instrument tubing/valve

The following six electrical/instrumentation components were classified as subject to an AMR (only pressure boundary/body):

- control valve
- temperature element
- radiation element
- temperature indicator
- solenoid valve
- temperature indicating controller

The remaining device types listed in Table 5.3-1 of Appendix A to the LRA, including the piping, check valve, hand valve, pump/drive assembly, relief valve, and tank, were reviewed to verify that the applicant did not omit any components that should be subject to an AMR. The staff found no omissions or mistakes in classification of these components.

The staff agrees with the applicant's determination, which is consistent with10 CFR 54.21(a)(1). The staff reviewed the information in Section 5.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the CC system to meet the requirements of 10 CFR 54.21(a)(1).

2.2.3.15 Compressed Air System

In Section 5.4, "Compressed Air System," of Appendix A to the LRA, the applicant described the system and the components that are within the scope for license renewal, and identified which of those components are subject to an AMR.

2.2.3.15.1 Summary of Technical Information in Application

As described in the LRA, the compressed air system consists of the instrument air (IA), plant air (PA), and saltwater air (SWA) subsystems for each unit. The IA subsystem is designed to produce a reliable supply of dry and oil-free air for pneumatic instruments and controls and for pneumatically operated containment isolation valves. The PA subsystem is designed to meet necessary service air requirements for plant maintenance and operation. The SWA subsystem provides a backup supply of compressed air to most safety-related air-operated components.

The IA subsystem incorporates two non-safety-related, 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. An emergency backup tie from the PA header automatically supplies air to the IA subsystem if the pressure at the IA filter and dryer assembly falls below a preset value. The PA service header isolation valves also automatically shut if the pressure falls below a set value so the PA compressors discharge only to the IA subsystem.

The PA system consists of one non-safety-related, full-capacity PA compressor with an inlet filter, aftercooler, and moisture separator that discharges to the PA air 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 via the PA service header. A system cross-tie between the Unit 1 and Unit 2 PA subsystems has been provided for the PA headers.

A continuous supply of IA is provided to hold various pneumatically operated valve actuators in the positions necessary for plant operating conditions. Under normal operating conditions, one IA compressor operates and the second IA compressor remains on automatic standby. The PA subsystem is normally cross-connected between units, with one PA compressor operating and supplying both units' loads, and the other PA compressor in standby. The power supply for the air compressors is the normal distribution system and it can be backed up by the EDGs. Accumulators are located at various locations throughout the plant and act as safety reservoirs and also reduce system pressure pulsations.

In the event that the IA and PA compressors become unavailable, such as following load shedding due to a safety injection actuation signal (SIAS), two safety-related SWA compressors will provide a backup supply of compressed air to most safety-related components. These compressors are automatically started upon receipt of a SIAS and can also be operated from a local panel. The SWA compressors supply the SWA header that distributes air to all saltwater (SW) isolation valves for the service water heat exchangers, component cooling heat exchangers, and the emergency core cooling system pump room air coolers. The SWA 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.

The applicant indicated that the compressed air system has an interface with the service water system (Section 5.17 of Appendix A to the LRA), which supplies cooling water to the IA and PA compressors and aftercoolers. The compressed air system also has interfaces with the many systems that have components being supplied with compressed air. Any local air set or accumulator associated with a specific load is typically included (for license renewal purposes) within the boundaries of the system being supplied.

The compressed air system is within the scope of license renewal based on 10 CFR 54.4(a). In Appendix A to the LRA, the applicant identified the following intended functions for the compressed air system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide a vital auxiliary air supply, via the saltwater air subsystem, for components used to mitigate design-basis events.
- Provide a vital auxiliary air supply, via the auxiliary feedwater air subsystem, for components used to mitigate design-basis events.
- Provide a vital auxiliary air supply, via the 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 for the system liquid or gas or both.
- Maintain electrical continuity or provide protection or both of the electrical system.
- Provide seismic integrity or protection or both of safety-related components.

The applicant also determined that the following were intended functions of the compressed air system based on the requirements of 10 CFR 54.4(a)(3):

- For environmental qualification — Maintain functionality of electrical components as addressed by the Equipment Qualification (EQ) Program.
- For fire protection — Supply compressed air to essential loads to ensure safe shutdown in the event of a fire.

The applicant also noted that all components of the compressed air system that are within the scope of license renewal under Section 54.4(a)(3) (because they require environmental qualification) are also safety-related. Some of the components relied on to demonstrate compliance with fire protection requirements (10 CFR 50.48) are not safety-related, and are identified as within the scope of license renewal based only on the criteria of 10 CFR 54.4(a)(3). The applicant also noted that all components of the compressed air system that support the 10 intended functions identified above, with the exception of the fire protection function, are safety-related and seismic Category I.

On the basis of the 10 intended functions listed above, the portion of the compressed air system that is identified by the applicant as within the scope of license renewal includes all safety-related components in the system (electrical, mechanical, and instrument) and their supports. Safety-related portions of the compressed air system include those that support the 10 intended functions listed above for meeting the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2), and the EQ-intended function in accordance with the requirements of 10 CFR 54.4(a)(3).

Also identified by the applicant as within the scope of license renewal are certain non-safety-related portions of the compressed air system required for fire protection in 10 CFR 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 postulated fire, as required by 10 CFR Part 50, Appendix R. Each of the compressed air system compressors, that is, IA, PA, and SWA compressors, supports 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 the safety-related or non-safety-related portions of the system in the event of a fire include service water valves, main steam isolation valves, EDGs, saltwater valves, component cooling valves, safety injection valves, and containment spray valves. However, all of the non-safety-related portions of the compressed air system subject to an AMR are evaluated in the fire protection evaluation in Section 5.10 of the LRA.

In Appendix A to the LRA, the applicant identified a total of 29 device types within the safety-related portions of the compressed air system as being within the scope of license renewal. Of these 29 device types, the applicant identified 10 that are subject to an AMR. The 10 device types are piping; six valve types (check, control relief, pressure control, motor-operated and hand valve); air accumulator; filter; and pump (air amplifier). For the air-accumulator device type, the applicant identified that safety-related components that are integral to the skid-mounted SWA compressors are excluded. For the hand valve device type, the applicant noted that instrument line manual drain, equalization, and isolation valves in the compressed air system that are subject to an AMR are evaluated for the effects of aging in the Instrument Lines Commodity Evaluation in Section 6.4 of Appendix A to the LRA, and instrument line manual root valves are evaluated in Section 5.4 of Appendix A to the LRA. With regard to piping type, the applicant noted that all tubing and tubing supports are also evaluated in Section 6.4, "Instrument Lines," of Appendix A to the LRA. Lastly, the applicant noted that many pressure control valves, regulating valves, and reducing valves in the compressed air system do not have unique identifiers in the plant's Master Equipment List. These valves are also reviewed in the

Instrument Lines Commodity Evaluation in Section 6.4 of Appendix A to the LRA. The applicant further indicated that maintenance of the pressure boundary of the compressed air system is the only passive intended function associated with the system that is not addressed in one of the commodity evaluations of the LRA.

As identified by the applicant, some components in the compressed air system are common to many systems and, therefore, have been included in the separate commodity report sections, which address those components for the entire plant. Hence, the following common components were not included in the individual system section for compressed air:

- Structural supports for piping, cables, and components that are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA.

- Electrical instrumentation, control, and power cabling, which is evaluated in Section 6.1, "Cables," of Appendix A to the LRA. This commodity evaluation completely addresses the passive intended function titled "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 instrument themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

- Also, as noted above, all tubing and many pressure control valves, regulating valves, and pressure-reducing valves without unique identifiers are evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.15.2 Staff Evaluation

The staff reviewed Section 5.4 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the compressed air system components and supporting structures are within the scope of license renewal in accordance with the requirements in 10 CFR 54.4, and subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the compressed air system (NRC letters to BGE dated August 21 and September 24, 1998), and by letter dated November 2, 1998, the applicant responded to those RAIs.

2.2.3.15.2.1 Compressed Air System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the compressed air system, to determine if there were any portions of the system piping and other components that the applicant did not identify as within the scope of license renewal. In the LRA, the applicant identified that the compressed air system has an interface with the service water system, which provides cooling water to the IA and PA compressors and aftercoolers. The service water system is within the scope of license renewal and is addressed in Section 5.17, "Service Water System," of Appendix A to the LRA and Section 2.2.3.17 of this SER. The compressed air system also interfaces with many systems that have components being supplied with compressed air. Any local air set or accumulator associated with a specific load is typically included within the license renewal boundaries of the system being supplied with the compressed air. The staff reviewed all the identified license renewal interface boundaries within the compressed air system in addition to all the identified interface boundaries with other systems, structures, and components. The staff also reviewed the system flow diagrams to verify that there were no significant interface boundaries that were not identified by the applicant in the LRA. If the portions of the compressed air system beyond the license renewal interface boundary (i.e., portions of the system that are not within the scope of license renewal) were verified by the staff to have no intended functions, then the components within those portions of the system were also deemed to have no intended function and were eliminated from further consideration. The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA to determine if there were any structures and components having intended functions that may have been omitted from consideration within the scope of the rule.

Many of the components of the compressed air system that are within the scope of license renewal are addressed either in the commodity report sections of the LRA, or in the sections that evaluate the individual systems that are within the scope of license renewal and require the use of compressed air. As a test to determine if the applicant omitted a component from its list of components that are within the scope of license renewal, the staff requested (NRC Question No. 5.4.4) that the applicant clarify what equipment comprised the auxiliary feedwater (AFW) air subsystem and the containment air subsystem. In the LRA, it was not clear whether these two subsystems were separate air systems with their own air compressors or were part of the IA or PA system. The applicant's response clarified that the AFW air system is a grouping of safety-related components dedicated to supplying air to certain safety-related valves required for the operation of the AFW system, and that the containment air subsystem is a grouping of safety-related components dedicated to supplying air to certain safety-related valves inside the containment. The components and associated supporting structures for both these subsystems are within the scope of license renewal. In response to NRC Question No. 5.4.2, the applicant also stated that there are no pressure-retaining components in the compressed air system whose failure would result in loss of system pressure that are not within the scope of license renewal. Because the specific license renewal interface points were not depicted on a simplified drawing in the LRA as was done for the other LRA system sections, the staff asked the applicant to more clearly define the interface points to help assess what portions of the compressed air system were within the scope of license renewal. In its response to NRC Question No. 5.4.1, the applicant presented a simplified drawing of the compressed air system, which clearly defined that essentially all of the compressed air system was within the scope of license renewal and is included in an AMR either in Section 5.4 of Appendix A to the LRA or in one of the commodity report evaluation sections.

As described above, the staff reviewed the information presented in Section 5.4 of Appendix A to the LRA and the additional information provided by the applicant in response to the staff's RAIs. On the basis of that review and upon the applicant's response to the staffs' RAIs, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the compressed air system, and the associated structures and components thereof, that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.15.2.2 Compressed Air System Subject to an Aging Management Review

In Section 5.4.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the compressed air system are within the scope of the license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.4-1 of Appendix A to the LRA). The staff reviewed the information to verify that the applicant's grouping was correct.

The staff reviewed the information in Table 5.4-1 Appendix A to the LRA and verified that the applicant identified all components that are subject to an AMR. Of 30 device types within the scope of the license renewal rule, 19 are electrical/instrumentation components. The staff reviewed these device types to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 19 components, the applicant classified the following 9 as having only active functions and, therefore, not requiring an AMR:

- coil
- motor
- power lamp indicator
- fuse
- position-indicating lamp
- relay
- hand switch
- position switch
- indicating lamp

The staff agrees with the applicant's determination that these 9 electrical/instrumentation components require moving parts or a change in configuration or properties to perform their intended functions.

One device type, solenoid valve, is subject to a replacement based on a qualified life or specified time period and does not require an AMR. The basis for excluding solenoid valves from an AMR is valid provided that the valve bodies are also replaced, rather than refurbished, because the valve body may have a pressure-retaining function, like that described for many of the other systems. Alternatively, the pressure boundary provided by the valve body may not be relied upon for the system intended functions, as is described for the safety injection system in Section 2.2.3.28.1 of this SER. Verification of the appropriate exclusion basis for solenoid valves in the compressed air system and the containment spray system was Confirmatory Item 2.2.3.17.2.2-1 in the previous SER.

In the July 2, 1999 letter, the applicant stated that the solenoid valves in the compressed air system are replaced based on a qualified life that is less than 40 years. Because the applicant now provides the appropriate exclusion basis from an AMR for solenoid valves in the compressed air system, Confirmatory Item 2.2.3.17.2.2-1 is closed.

Two device types, level switch and temperature switch, do not require an AMR because of specific exclusion by the license renewal rule under 10 CFR 54.21(a)(1)(i), that is, all components included with the air compressors.

The following five device types are evaluated in Section 2.2.3.32, "Cables,"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrumentation Line," of this SER:

- control/power cabling
- pressure indicator
- instrument tubing/valve
- pressure switch
- panel

The two electrical/instrumentation components remaining, control valve and MOV, were determined by the applicant to be subject to an AMR (only pressure boundary/body). The staff also agrees with the applicant's determination that control valves and MOVs perform only the pressure boundary intended function without moving parts or without a change in configuration or properties.

The staff also reviewed the non-electrical components in the compressed air system in order to verify that the applicant identified all the structures and components subject to an AMR. Of the 11 non-electrical components, the applicant correctly identified drain traps and air compressors as not requiring an AMR because of specific exclusion by the license renewal rule under 10 CFR 54.21(a)(1)(i). The applicant evaluated structural supports for piping, cabling, and other components in Section 3.1 of Appendix A to the LRA. The eight non-electrical component types remaining, air accumulators, compressed air system piping, check valves, filters, hand valves, PCVs, pumps and relief valves were determined by the applicant to be subject to an AMR. The staff found no additional structures and components requiring an aging management review. The staff also agrees with the applicant's determination that these components perform only the pressure boundary intended function without moving parts or without a change in configuration or properties.

On the basis of this evaluation, the staff finds reasonable assurance that the applicant has appropriately identified all the structures and components for the compressed air system that are subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.16 Containment Isolation Group

In Section 5.5, "Containment Isolation Group," of Appendix A to the LRA, the applicant described portions of the containment isolation group and the components therein that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.16.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, numerous systems have a containment isolation function and, therefore, have containment isolation valves, containment penetrations, and associated piping and test connections. The components that perform the containment isolation function in systems that are evaluated in other sections of the LRA are included within those sections. Containment isolation valves are designed to ensure leak-tightness and reliability of operation.

In Appendix A to the LRA, the applicant identified the following intended functions for the containment isolation group based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide containment isolation;
- Maintain electrical continuity and provide protection of the electrical system; and
- Maintain the pressure boundary of the system (liquid or gas or both).

The applicant also determined the following intended function of the containment isolation group based on the requirements of 10 CFR 54.4(a)(3):

For equipment qualification

- Maintain functionality of electrical components as addressed by the equipment qualification (EQ) program

- Provide information used to assess the condition of the plant and its environs during and following an accident; and

- Provide containment isolation valve position indication.

On the basis of the intended functions stated above, the portion of the containment isolation group that is identified by the applicant as within the scope of license renewal includes all safety-related components (electrical, mechanical, and instrument) and their supports making up the containment penetration pressure boundary. Also included are the safety-related components (electrical, mechanical, and instrument) and their supports associated with the waste gas decay tank pressure boundary. The applicant identified 10 device types as being within the scope of license renewal for the containment isolation group. The applicant identified all 10 device types as subject to an AMR. Eight of the device types are piping (Class HB and

HC); five valve types (check, control, relief, motor operated, and hand valve), and tank. The applicant also indicated that the remaining two device types (level switch and pressure transmitter) were evaluated in the Instrument Line and Commodity Evaluation in Section 6.4 of Appendix A to the LRA.

2.2.3.16.2 Staff Evaluation

The staff reviewed Section 5.5 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the containment isolation components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the containment isolation group (NRC letter dated September 2, 1998), and by letter dated November 12, 1998, the applicant responded to the RAIs.

2.2.3.16.2.1 Containment Isolation Group Within the Scope of License Renewal

The staff reviewed Section 5.2, "Isolation System," of the UFSAR and compared the description of the structures, systems, and components in the UFSAR to the description in the application to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. The plant's containment isolation valves are listed in Table 5-3 of the UFSAR. Because some of the valves and their associated components that perform the containment isolation function are evaluated in other sections of Appendix A to the LRA, the staff asked the applicant (NRC Question 5.5.1) to clarify whether all the containment isolation valves listed in Table 5-3 of the UFSAR are subject to an AMR. In response to NRC Question No. 5.5.1, the applicant stated that all the containment isolation valves listed in Table 5-3 are subject to an AMR. In addition, the applicant provided a cross-reference, which showed where each penetration in Table 5-3 was evaluated in the LRA. The staff also reviewed Section 5.2 of the UFSAR to determine if there were any safety-related functions that were not identified as intended functions in Appendix A to the LRA to determine if there were any structures and components having intended functions that might have been omitted from consideration within the scope of license renewal. The staff found no omissions and therefore, concluded there is reasonable assurance that the applicant adequately identified those portions of the containment isolation system and its associated (supporting) structures and components that fall within the scope of license renewal in accordance with 10 CFR Part 54.

As described above, the staff has reviewed the information in Section 5.5 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAI. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the containment isolation system and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.16.2.2 Containment Isolation Group Subject to an Aging Management Review

The staff reviewed the 10 devices identified in Section 5.5 of Appendix A to the LRA and finds that the containment isolation group valves (except for the valve body), level switch, and pressure transmitter have active functions and are subject to existing testing or inspection programs, as well as to repair or replacement. Pursuant to 10 CFR 54.21(a)(1)(i), these components are not subject to an AMR; hence, they are not required to be reviewed in aging management programs.

Pursuant to 10 CFR 54.21(a)(1)(i), the containment isolation group piping, component supports, tank, certain electrical controls, and power cabling are subject to an AMR because they perform an intended safety function without moving parts, or without a change in configuration or properties.

As described above, the staff has reviewed the information concerning system level scoping and component level scoping in Section 5.5 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAI. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components for the containment isolation group subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.17 Containment Spray System

In Section 5.6, "Containment Spray (CS) System" of Appendix A to the LRA, the applicant described portions of the CS system and the components therein that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.17.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the CS system is designed to limit the pressure and temperature of the containment atmosphere so the associated design limits are not exceeded following design-basis events (DBEs). This is accomplished by spraying borated water into the containment atmosphere. The CS system is also utilized to remove heat from the reactor coolant system (RCS) during plant cooldown and to maintain the RCS temperature during plant shutdown. The CS system for each unit consists of two electric-motor-driven pumps, two shutdown cooling heat exchangers, two CS headers, and associated valves, piping, instrumentation, and controls.

In Appendix A to the LRA, the applicant identified the following intended functions for the CS system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide containment pressure control and cooling;
- Provide containment isolation;

- Maintain electrical continuity and provide protection or both of the electrical system;
- Maintain the pressure boundary of the system; and
- Restrict flow to a specified value in support of the DBE response.

The applicant also determined that the following were intended functions of the CS system based on the requirements of 10 CFR 54.4(a)(3):

- For post-accident monitoring — Provide information used to assess the conditions of the plant and its environs during and following an accident;

- For equipment qualification — Maintain functionality of electrical components as addressed by the EQ program; and

- For fire protection — Provide RCS heat removal to ensure safe shutdown.

On the basis of the intended functions stated above, the portion of the CS system that is identified by the applicant as within the scope of license renewal includes all components (electrical, mechanical, and instrument) and their supports along the shutdown cooling, minimum-flow recirculation, and injection flowpaths as shown on Figure 5.6-1 of Appendix A to the LRA. The applicant identified a total of 33 device types from within the CS system as being within the scope of license renewal. Of these 33 device types, the applicant identified 13 that are subject to an AMR. The 13 device types are Class "GC" and "HC" piping (including spray nozzles), five valve types (motor operated, check, control, relief, and hand valve), pump/driver assembly, flow element, temperature element, temperature indicator, and flow orifice.

The applicant also indicated that some components in the CS system that are common to many systems have been discussed in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not discussed in the individual system sections:

- Structural supports for piping, cables, and components that are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA, except for the shutdown cooling heat exchanger supports that are addressed in Section 5.6 of Appendix A to the LRA;

- Electrical control and power cabling, which is evaluated in Section 6.1 of Appendix A to the LRA; and

- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instruments themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.17.2 Staff Evaluation

The staff reviewed Section 5.6 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the CS system components and supporting structures within the scope of license renewal in 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the CS system (NRC letter dated September 2, 1998), and by letter dated November 4, 1998, the applicant responded to those RAIs.

2.2.3.17.2.1 Containment Spray System Within the Scope of License Renewal

The staff reviewed portions of the UFSAR, including Section 6.4, "Containment Spray System," to determine if there were any portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. In Appendix A to the LRA, the applicant identified a number of license renewal interface boundaries within the CS system. On one side of the interface boundary, the system piping and other components are within the scope of license renewal; on the other side of the interface boundary, the piping and other components are not within the scope of license renewal. A license renewal interface boundary usually exists within the system at a point where non-safety-related portions of the system piping interface with safety-related portions because the non-safety-related portions do not perform any intended functions and the safety-related portions perform at least one intended function. Appropriate isolation capability, which is part of the existing licensing and design basis for the system, is provided at each of the license renewal interfaces. Isolation capability was not reevaluated for license renewal because each of the interfaces is part of the current licensing basis and was previously found acceptable by the staff. Interface boundaries also exist where the CS system interfaces with other systems through various components such as heat exchangers, equipment cooling coils, or head tank fill piping. The staff reviewed all the identified license renewal interface boundaries within the CS system in addition to all the identified interface boundaries with other systems, structures, and components. The staff also reviewed the flow diagrams for the safety injection and containment spray systems (UFSAR Figures 6-1 and 6-10) to verify that there were no interface boundaries that were not identified by the applicant in the LRA. If the portions of the CS system beyond the license renewal interface boundary (i.e., portions of the system that are not within the scope of license renewal) were verified by the staff to have no applicable intended functions, then the components within those portions of the system were eliminated from further consideration.

The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified in Appendix A to the LRA to determine if there were any structures and components that might have been omitted from consideration within the scope of license renewal. The staff found that the applicant had not omitted any interface boundaries and intended functions (refer to detailed discussion in next paragraph), and therefore, concluded there is reasonable assurance that the applicant adequately identified those portions of the CS system and its associated (supporting) structures and components that fall within the scope of license renewal in accordance with 10 CFR Part 54.

To help ensure that those portions of the CS system identified as not within the scope of license renewal at these interfaces did not perform any intended functions and, therefore, did not have any components subject to an AMR, the staff requested additional information from the applicant based on the information in the UFSAR and the LRA. Section 6.4.2 of the UFSAR states that the containment spray is expected to be effective in removing fission products from the containment atmosphere. NRC Question No. 5.6.1 asked why this intended function was not included as part of the system description or the scoping results. In response, the applicant stated that this active function performed by the CS system was inadvertently omitted. The applicant further stated that this omission would not affect the AMR results since, as an active function, the CS components that accomplish the active function are not required to be evaluated as stated in 10 CFR 54.21(a)(1)(i). The staff believes that two passive components that support this active function, the trisodium phosphate baskets and the containment sump, are necessary for the CS system to perform the fission-product removal function. The trisodium phosphate baskets were identified as subject to an AMR (Table 3.3A-1 of Appendix A to the LRA). The containment sump is included within the scope of license renewal (Figure 5.15-1 in Appendix A to the LRA) and is subject to an AMR (Table 3.3A-1 of Appendix A to the LRA). Therefore, the staff finds that the SCs required to support this intended function have been adequately dispositioned.

In response to NRC Question No. 5.6.4, regarding exclusion of the non-safety-related emergency dousing function of the CS system from the scope of license renewal, the applicant referenced Section 6.7.2 of the UFSAR. This section explains that the CS system is capable of dousing the charcoal filters in the iodine removal units. Although not specifically mentioned in Section 5.6.1.2 and Table 5.6-1 of Appendix A to the LRA, the applicant confirmed that the containment spray nozzles are clearly shown as within the scope of license renewal in Figure 5.6-1 of Appendix A to the LRA. The CS system supplies spray water to the iodine removal units via piping, valves, and nozzles downstream of normally shut isolation valves. The primary purpose of the dousing system is to cool the charcoal, should overheating occur during their use following a design-basis accident. Open Item 2.2.3.17.2.1-1 questioned whether this ability to provide fire protection was required by 10 CFR 50.48.

In the July 2, 1999, response to Open Item 2.2.3.17.2.1-1, the applicant stated that it performed an analysis supporting a 10 CFR 50.59 evaluation (Log No. 90-B-061-086-R2, dated December 4, 1990). The analysis showed that the maximum post-LOCA charcoal bed temperature would not cause iodine desorption or charcoal bed ignition. This resulted in a plant modification, which isolated the emergency dousing system from service in modes 1 through 4. Manual valves may be opened in modes 5 and 6, so that the dousing system is available to provide fire protection during maintenance activities. The applicant removed the charcoal filter dousing system from the CCNPP Fire Hazards Analysis (FHA) on June 4, 1997. This is consistent with the guidance of Section F.1(a) of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1, which states that fire suppression systems should be provided based on the FHA. Furthermore, the BTP does not specify an automatic fixed suppression system for the charcoal filter unless there is a hazard that could jeopardize safe plant shutdown.

Therefore, the emergency dousing system is not within the scope of license renewal on the basis that the emergency dousing function of the CS system is not credited as part of the current licensing basis for meeting the requirements of 10 CFR 50.48 in accordance with the guidance of Appendix A to BTP APCSB 9.5-1. Therefore, the staff concludes that the emergency dousing system piping, valves, and nozzles downstream of the normally shut isolation valves are not within the scope of license renewal and Open Item 2.2.3.17.2.1-1 is closed.

As described above, the staff has reviewed the information in Section 5.6 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the CS system and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.17.2.2 Containment Spray System Subject to an Aging Management Review

In Section 5.6.1.2 of Appendix A to the LRA, the applicant identified the structures and components of the CS system that are within the scope of the license renewal. The applicant divided those structures and components into device types not subject to an AMR and device-types subject to an AMR (listed in Table 5.6-1 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct.

The applicant has used the following CS system functions as a basis for determining whether or not components are subject to an AMR:

- To maintain electrical continuity and/or provide protection of the electrical system,
- To maintain the pressure boundary of the system (liquid and/or gas), and
- To restrict flow to specified value in support of the design-basis earthquake response.

The staff finds this methodology acceptable because it should result in the appropriate components identified for an AMR.

Of the device types within the scope of the license renewal rule, 27 device types are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit electrical/instrumentation components that should be subject to an AMR.

Of the 27 components, the applicant classified the following 17 as having only active functions and, therefore, not requiring an AMR:

- coil
- flow indicator
- hand switch
- power lamp indicator
- MOV operator
- position indicating lamp
- control valve operator
- fuse
- current/pneumatic device
- 4-kV motor
- relay
- position switch
- voltage current device
- hand indicator controller
- ammeter
- 125/250-V dc motor
- solenoid valve

The following five device-types are evaluated in Section 2.2.3.32, "Cables," or Section 2.2.3.35, "Instrumentation Line," of this SER:

- flow transmitter
- pressure switch
- pressure transmitter
- control/power cabling
- instrument tubing/valves

The following five electrical/instrumentation components evaluated in this section were classified as subject to an AMR (only pressure boundary/body):

- control valve
- flow element
- MOV
- temperature element
- temperature indicator

The remaining device types listed in Table 5.6-1, including the piping, hand valve, heat exchanger, pump/drive assembly, relief valve, and check valve, were reviewed to verify that the applicant did not omit components that should be subject to an AMR. The staff finds no omissions or mistakes in classification of these components. On the basis of the applicant's reasoning, the staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1), except for solenoid valves.

The basis for excluding solenoid valves from an AMR may be valid provided that the pressure boundary provided by the valve body is not relied upon for the system intended functions, as is described for the safety injection system in Section 2.2.3.28.1 of this SER. The solenoid valve pressure boundary function has been properly included in the scope of the AMR for other systems (for example, reactor coolant system in Section 2.2.3.9.2.2). Verification of the appropriate exclusion basis for solenoid valves in the containment spray system and the compressed air system (see Section 2.2.3.15.2.2) was identified as Confirmatory Item 2.2.3.17.2.2-1 in the previous SER.

In the July 2, 1999 letter, the applicant stated that the bodies of the solenoid valves in the containment spray system do not perform a pressure boundary intended function, i.e., they do not form part of the pressure boundary for the CS system. Because the applicant now provides the appropriate exclusion basis from an AMR for solenoid valves in the containment spray system, Confirmatory Item 2.2.3.17.2.2-1 is closed.

The staff has reviewed the information submitted in Section 5.6 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of its review, the staff finds that there is a reasonable assurance that the applicant has appropriately identified the structures and components for the CS system subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.18 Diesel Fuel Oil System

In Section 5.7, "Diesel Fuel Oil (DFO) System," of Appendix A to the LRA, the applicant described the DFO system and the DFO system components that are within the scope for license renewal, and identified which of those components are subject to an AMR.

2.2.3.18.1 Summary of Technical Information in the Application

The DFO system provides a reliable source of fuel oil to the emergency diesel generators (EDGs), the auxiliary heating boiler, the SBO generator, and the diesel-driven fire pump. The DFO system for the three EDGs consists of two (Nos. 11 and 21) seismic Category I, above-ground fuel oil storage tanks (FOSTs) and associated piping and valves. The pumps that transfer the fuel oil from the tanks to the EDGs are within the scope of license renewal, but they are addressed in the EDG system section (Section 5.8) of Appendix A to the LRA and evaluated in Section 2.2.5.8 of this SER. As a result of the system level scoping, the applicant identified that, pursuant to 10 CFR 54.4(a), the portions of the DFO system that are within the scope of license renewal include all components (electrical, mechanical, and instrument) and their supports, from the unloading station to the FOSTs, the FOSTs, supply headers, including cross-connects, and piping to just upstream of the Y-strainer installed in the suction pipe to the DFO transfer pumps. The fuel oil transfer pump suction line, transfer pumps, and the day tanks are evaluated as part of the EDG system in Section 2.2.5.8 of this SER. The application described all the intended functions of the DFO system that were determined necessary for license renewal based on the requirements of 10 CFR 54.4. The DFO system is within the scope of license renewal based on 10 CFR 54.4(a). The applicant identified the following intended functions of the DFO system based on 10 CFR 54.4(a)(1):

- Provide vital auxiliary function to the power distribution system by supplying fuel oil to the EDGs during design-basis events.

- Maintain the pressure boundary of the system.

The applicant also identified the following intended function of the DFO system based on the requirements of 10 CFR 54.4(a)(3):

- For fire protection — Provide essential fuel oil to EDGs and the diesel fire pump to ensure safe shutdown in the event of a postulated fire (includes isolation of nonessential auxiliary boiler and SBO DFO).

On the basis of the three intended functions listed above, the applicant identified 13 device types in the DFO system that have at least one intended function and, therefore, are within the scope of license renewal. Of these 13 device types, the applicant identified four that are subject to an AMR and not otherwise addressed in one of the commodity reports. These four device types are above-ground and underground piping, check valves, hand valves, and the FOSTs. The applicant also identified that maintenance of the pressure boundary is the only passive intended function associated with the DFO system that is not addressed by one of the commodity evaluations of Appendix A to the LRA.

The applicant indicated that some components in the DFO system that are common to many systems have been included in the separate commodity reports which address those components for the entire plant. Therefore, the following components were not included in the sections on individual systems:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1, "Component Supports," of Appendix A to the LRA.

- Electrical control and power cabling, which is evaluated in Section 6.1, "Cables," of Appendix A to the LRA.

- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4, "Instrument Lines," of Appendix A to the LRA.

2.2.3.18.2 Staff Evaluation

The staff reviewed Section 5.7 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the DFO system components within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR to meet the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the DFO system (NRC letter to BGE dated February 13, 1998), and by letter dated July 30, 1998, the applicant responded to those RAIs.

2.2.3.18.2.1 Diesel Fuel Oil System Within the Scope of License Renewal

During the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the DFO system, to determine if there were any portions of the DFO system piping or other components that might perform intended functions that were not described in the LRA. Essentially all portions of the DFO system were determined to perform at least one intended function and, therefore, essentially all portions and components of the DFO system are within the scope of license renewal and are identified as such by the applicant, either in Section 5.7 of Appendix A to the LRA or in other sections of the LRA. The staff reviewed the few remaining components of the DFO system to verify that they do not have any intended functions. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified as intended functions in the LRA and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

However, in the LRA, the applicant identified a non-safety-related line from FOST No. 21 to diesel generating room waste oil collecting tank (WOCT) No. 11 as not within the scope of license renewal. The applicant also did not identify or discuss a non-safety-related line from the concrete enclosure of FOST No. 21 that, according to the UFSAR, can be used to supply the EDGs in the event of the FOST's rupture. By letter dated February 19, 1998, the staff asked the applicant (identified as NRC Question No. 3 in the applicant's response) to provide further justification as to why neither of these lines were considered within the scope of license renewal since they appeared to perform the intended function of maintaining the DFO system pressure boundary during some design-basis events. The applicant responded to the RAI by letter dated July 30, 1998, indicating that the line from the FOST enclosure is not relied upon to remain functional during or following any design-basis events. The FOST enclosure is designed to protect the seismic Category I FOST No. 21 from tornado missiles and the FOST is not postulated to rupture as a result of any design-basis event. The applicant also noted that the line to WOCT No. 11 from FOST No. 21 is the FOST overfill line and there is no potential for draining the FOST if the line should rupture. Although the simplified drawing in Section 5.7 of Appendix A to the LRA showed this line coming out the bottom of the tank, it actually comes out near the top. As a result of the staff's review of the applicant's responses, the staff concurred with the applicant that these lines do not perform any intended functions important to license renewal and are not required to be within the scope of license renewal. Thus, the staff did not find any components that were not already identified by the applicant as being within the scope of license renewal.

As described above, the staff has reviewed the information presented in Section 5.7 of Appendix A to the LRA in addition to the information sent by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the DFO system and its associated structures and components (device types) that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.18.2.2 Diesel Fuel Oil System Subject to an Aging Management Review

In Section 5.7.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the diesel fuel oil (DFO) system were within the scope of the license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.7-1 of Appendix A to the LRA). The staff reviewed all the information submitted by the applicant to verify that the grouping of the DFO system structures and components was correct. As described in detail below, the staff finds reasonable assurance that the applicant has identified all the structures and components for the DFO system that are subject to an AMR in accordance with 10 CFR Part 54.21(a)(1).

The applicant identified 16 device types that need to be considered for an AMR. The staff reviewed all the components within the scope of the rule and verified that all the components were considered in these 16 device types. Of the 16 device types within the scope of the license renewal rule, 9 are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant identified all the components subject to an AMR that perform an intended function without moving parts or without a change in configuration or properties and that are not subject to replacement based on qualified life or specified time period. Of the nine electrical/instrumentation device types, the applicant classified the following six as having only active functions and therefore not requiring an AMR:

- fuse
- transformer
- hand switch
- indicating lamp
- motor
- relay

Three components that include level switches, electrical control and power cabling, and instrument tubing and valves, are evaluated in Section 2.2.3.32, "Cables;" or Section 2.2.3.35, "Instrument Lines" of this SER. No electrical/instrumentation components evaluated in this section were classified as subject to an AMR. The staff agrees with the applicant's determination of active components, which is consistent with 10 CFR 54.21(a)(1).

The staff also reviewed the non-electrical components in the diesel fuel oil system in order to determine whether the applicant has properly identified the structures and components subject to an AMR. The staff reviewed the information in Table 5.7-1 of Appendix A to the LRA to ascertain that the applicant has identified all components that are subject to an AMR.

The staff reviewed the information in Section 5.7.1.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components in the diesel fuel oil system that are subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.19 Emergency Diesel Generator System

In Section 5.8, "Emergency Diesel Generator (EDG) System," of Appendix A to the LRA, the applicant described the EDG system, its intended functions, and the associated structures and components of the EDG system that are within the scope of license renewal and identified which of those structures and components are subject to an AMR.

2.2.3.19.1 Summary of Technical Information in the Application

As described in the LRA, the EDGs are 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. Four EDGs (1A, 1B, 2A, and 2B) are provided for the plant, although each unit requires only one EDG to supply the minimum power requirements for its engineered safety features (ESF) equipment. In addition, there is a fifth non-safety-related diesel generator (EDG-0C) that is identified as the SBO diesel generator. EDGs 1B, 2A, and 2B were part of the original plant design and are located in the same seismic Category I structure. EDG 1A and EDG 0C were installed more recently and each is located in its own separate structure. The EDG 1A structure is seismic Category I, but the SBO diesel generator structure is not designed to seismic Category I requirements since the SBO diesel generator is not required to withstand the effects of an earthquake. The auxiliary systems for the four EDGs (1A, 1B, 2A, and 2B) are also designed to seismic Category I requirements, but the SBO diesel generator auxiliaries are not. The auxiliary systems that support the EDGs are diesel fuel oil, lube oil, service water (SRW), starting air, keep-warm systems, instrumentation/controls, and intake and exhaust air.

EDG 1A and EDG 0C were furnished by Societe Alsacienne de Constructions Mechaniques de Mullhouse (SACM) and EDGs 1B, 2A, and 2B were furnished by Fairbanks Morse.

The license renewal rule, 10 CFR Part 54, recognizes that diesel engines and associated generators are active components and excludes them from the group of equipment that is subject to an AMR [10 CFR 54.21(a)(1)(i)]. All auxiliary components supplied as part of the engine and located on the engine skid (on the engine side of the auxiliary subsystem flexible couplings) are considered by the applicant and the staff to be part of the engine for the purposes of license renewal. The applicant stated that the passive, long-lived components associated with the engine auxiliaries outside the skid boundary and electrical equipment are subject to an AMR.

On this basis the boundaries of the EDG system for this license renewal evaluation are:

- Diesel Fuel Oil (DFO) System: The boundary between the DFO system [see Section 5.7, "Diesel Fuel Oil System," of Appendix A to the LRA] and the EDG system is just upstream of the Y-strainers installed in the suction pipe to the fuel oil transfer pumps.

- Service Water System (SRW): The boundary between the SRW system (LRA Section 5.17) and the EDG system is at the diesel cooler/SRW interface expansion joints (expansion joints are included in the EDG system section) and at the interface of SRW piping with the starting air subsystem air compressor.

- 4-kV Transformers and Buses System: The boundary between the EDG system and the 4-kV transformers and buses system is at the EDG side of the 4-kV breakers.

- Engineered Safety Features Actuation System (ESFAS): The boundary of the EDG system with the ESFAS is at the contact outputs from relay cabinets C67/68 for both Units 1 and 2.

The applicant stated that the following typical components are associated with the EDG auxiliaries outside the skid boundary:

- EDG fuel oil day tanks
- EDG starting air receivers
- EDG fuel oil transfer pumps
- EDG drip tanks
- EDG drip tank pumps
- EDG intake
- EDG exhaust mufflers
- EDG intake filters

Structures and components of the EDG system are within the scope of license renewal based on 10 CFR 54.4(a). The applicant stated that the following intended functions of the EDG system are based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- To provide the vital auxiliary power supply for components used to mitigate design-basis events (DBEs).

- To maintain the pressure boundary of the system (liquid or gas or both).

- To maintain electrical continuity or protect the electrical system or both.

- To maintain mechanical operability or protect the mechanical system or both.

- To provide seismic integrity or protect safety-related components or both.

In Appendix A to the LRA, the applicant also identified the following intended function of the EDG system based on the requirements of 10 CFR 54.4(a)(3):

- For environmental qualification — Provide information used to assess the environs and plant conditions during and after an accident.

- For fire protection — to provide vital auxiliary power for components used to ensure safe shutdown in the event of a postulated severe fire.

On the basis of the intended functions listed above, the applicant stated that the portion of the EDG system that is within the scope of license renewal consists of piping, components (e.g., heat exchangers, pumps, valves, and tanks), component supports, and instrumentation and cables supporting operation of the EDGs through the diesel lube oil, diesel fuel oil, diesel starting air, diesel combustion air, and diesel cooling water subsystems. The applicant identified 48 EDG system device types (i.e., component types) of the EDG system that are designated as within the scope of license renewal because they fulfill at least one of the intended functions.

The applicant also stated that some components in the EDG system that are common to many systems have been included in the separate commodity report sections of the LRA which address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1, "Component Supports," of Appendix A to the LRA.

- Electrical control and power cabling, which is evaluated in Section 6.1, "Cables," of Appendix A to the LRA.

- Instrument tubing and piping and the associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4, "Instrument Lines," of Appendix A to LRA.

For the new SACM diesel generators, EDG 1A and 0C, the applicant performed a one-time procedure to identify the components that passively support the pressure boundary or Class 1E functions that are also common with the existing Fairbanks Morse EDG components. The components of the SACM diesels were mapped to their corresponding components of the Fairbanks Morse EDGs. The applicant indicated that the mapping procedure gave assurance that all SACM components have been evaluated for an AMR through the evaluation process used for the Fairbanks Morse EDGs. The results of this mapping procedure are summarized below.

Diesel Lube Oil

No plausible aging was identified for any SACM diesel lube oil components.

Diesel Fuel Oil

Plausible aging was identified for the SACM diesel fuel oil tanks, basket strainer, tornado damper, and flame arrestor. In each case the material, environment, and age-related degradation mechanisms (ARDMs) for these SACM components were the same as the material, environment, and ARDMs for the corresponding Fairbanks Morse components.

Diesel Starting Air

No plausible aging was identified for the corresponding SACM diesel starting air components even though plausible aging was identified for the corresponding Fairbanks Morse diesel starting air components. The SACM diesel starting air components are SS and are subject to dry air; the corresponding Fairbanks Morse components are carbon steel and are subject to moist air.

Diesel Combustion Air

Plausible aging was identified for the SACM combustion air intake air filter and piping. In each case, the material, environment, and ARDMs for these SACM components are the same as the material, environment, and ARDMs for the corresponding Fairbanks Morse components. Plausible aging was identified for the SACM combustion air exhaust air muffler and piping. The material, environment, and ARDMs for the SACM exhaust muffler are the same as for the corresponding Fairbanks Morse muffler. The SACM exhaust piping is chromium-molybdenum; the Fairbanks Morse diesel exhaust piping is carbon steel. Therefore, the SACM exhaust piping is subject to a subset of the ARDMs affecting the Fairbanks Morse diesel exhaust piping.

Diesel Cooling Water

Plausible aging was identified for the SACM cooling water piping, tanks, and valves. These SACM components are made of the same material and are subject to the same ARDMs as the corresponding Fairbanks Morse piping, tanks, and valves even though the process fluid is different. The process fluid for the SACM diesel cooling water is a solution of ethylene glycol antifreeze in demineralized water. The process fluid for the Fairbanks Morse jacket cooling water is service water treated with hydrazine. The aging of the SACM radiators is expected to be bounded by the aging of the Fairbanks Morse jacket water cooling system piping.

In the few instances in which there was not a corresponding EDG component for a new SACM component, there were no plausible ARDMs from the material/environment characteristics of the new SACM component. Therefore, for purposes of license renewal, the aging, and thus the management of aging, for the new SACM diesel auxiliary systems are enveloped by the aging and management program for the Fairbanks Morse diesel auxiliary systems. Any aging discovered by the aging management program for the Fairbanks Morse diesels will result in corrective action and a review for applicability to the corresponding SACM auxiliary system.

Of the 48 device types the applicant identified as within the scope of license renewal, the applicant identified 11 that are subject to an AMR. These 11 device types are piping, filter, muffler, drain trap, Y-strainer, relief valve, check valve, hand valve, pump, accumulator, and tank. The applicant further stated that maintenance of the pressure boundary of the liquid or gas or both is the only passive intended function associated with the EDG system not addressed by one of the commodity evaluations in other sections of Appendix A to the LRA.

2.2.3.19.2 Staff Evaluation

The staff reviewed Section 5.8 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified and listed the EDG system components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review the staff requested additional information regarding the EDG system (NRC letters to BGE dated August 27 and September 24, 1998), and by letter dated November 4, 1998, the applicant responded to those RAIs.

2.2.3.19.2.1 Emergency Diesel Generator System Within the Scope of License Renewal

During the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the EDG system, to determine if there were any system components that the applicant did not identify as within the scope of license renewal but that were necessary to perform one of the identified intended functions of the EDG system. The staff also reviewed the design basis for the EDG system as described in the UFSAR to determine if there were any additional system functions that were intended functions and, therefore, might require the functioning of components of the EDG system that the applicant did not identify as within the scope of license renewal.

The staff's review of the UFSAR and flow diagrams, which included reviewing the functions of components identified as being outside the scope of license renewal, did not uncover any additional structures or components of the EDG system that should have been within the scope of license renewal. The applicant stated that virtually all of the components of the EDG system are within the scope of license renewal. However, the staff did request additional information via NRC Question No. 5.8.1 to help ensure there were no omissions from the applicant's list of components within the scope of license renewal. Figure 5-8.1 of Appendix A to the LRA is a simplified drawing that identifies the EDG system boundary for the diesel air starting system and appeared, to the staff, to indicate that a check valve upstream (air supply to the receiver) of the air receiver is not within the scope of license renewal. As this check valve appears to be a license renewal interface between the air receiver and the air compressor piping, the staff asked the applicant to clarify whether the check valve is within the scope of license renewal. In its response, the applicant verified that the check valve and the piping between the check valve and the air receiver were within the scope of license renewal.

As a result of its review, the staff also did not identify any additional intended functions that could result in additional components (components not identified by the applicant) being within the scope of license renewal and hence, possibly subject to an AMR.

As described above, the staff has reviewed the EDG system information presented in Section 5.8 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified those EDG system structures and components (device types) within the scope of license renewal in accordance with the requirements in 10 CFR 54.4.

2.2.3.19.2.2 Emergency Diesel Generator System Subject to an Aging Management Review

The applicant divided structures and components within the scope of license renewal into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.8-2 of Appendix A to the LRA). The staff reviewed the information to verify that the grouping was correct.

Of the device types within the scope of the license renewal rule, 35 device types were considered to be electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit electrical/instrumentation components within the scope of the rule that should be subject to an AMR. Of the 35 components, the applicant classified the following 28 as having only active functions and, therefore, not requiring an AMR:

- annunciator
- circuit breaker
- control switch
- voltage regulator
- EDG
- isolator
- fan
- fuse
- governor
- hand switch
- indicator
- indicating light
- motor
- relay
- speed controller
- speed indicator
- speed switch
- temperature controller
- temperature switch
- temperature transmitter
- transformer
- indicating lamp
- position-indicating light
- disconnect

The following seven components are evaluated in Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrument Lines," of this SER.

- level indicator
- pressure switch
- control/power cabling
- level switch
- pressure indicator
- motor control center
- instrument tubing/valves

No electrical/instrumentation components evaluated in this section were classified as subject to an AMR. The remaining device types listed in Table 5.8-2 of Appendix A to the LRA, including the piping, filter, muffler, drain trap, Wye strainer, relief valve, check valve, hand valve, pump, accumulator, and tank were reviewed to verify that the applicant did not omit components that should be subject to an AMR. One device type (heat exchanger) is a skid-mounted component on the Fairbanks Morse EDG, and therefore, is not subject to an AMR. On the basis of the applicant's reasoning, the staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

The staff has reviewed the information submitted in Section 5.8 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of its review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the EDG system in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.20 Feedwater System

In Section 5.9, "Feedwater System (FWS)," of Appendix A to the LRA, the applicant described the portion of the FWS and its associated structures and components that are within the scope of license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.20.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the FWS transfers condensate from the condensate system to the steam generators (SGs), raises the temperature of the feedwater to increase plant efficiency, and controls the rate of flow to the SGs to match the steam flow demand by the plant turbine generators. The major components of the FWS are piping, steam-driven pumps, high-pressure feedwater heaters, regulating valves, isolation valves, and header check valves. Also included are SG secondary-side pressure and level instrumentation loops. This instrumentation provides SG level control information as well as the protective functions of SG isolation and auxiliary feedwater (AFW) initiation.

During the system level scoping evaluation, the applicant identified that the portion of the FWS within the scope of license renewal pursuant to 10 CFR 54.4(a) includes all components (electrical, mechanical, and instrument) and their supports, from the inlet side of the motor-operated feedwater isolation valves to the SG nozzle. Also included are SG secondary-side water level and pressure-indicating instrumentation loops, including the root isolation valves and all downstream components (valves, tubing, instruments). The LRA describes all the intended functions of the FWS that it determined were necessary for license renewal based on the requirements of 10 CFR 54.4.

Structures and components of the FWS are within the scope of license renewal based on 10 CFR 54.4(a). The applicant identified the following intended functions of the FWS based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide containment overpressure protection.
- Prevent reverse flow from the SG via check valve closure.
- Send signals to the engineered features actuation system (ESFAS) and provide SG isolation.
- Provide signals to the reactor protective system (RPS).
- Provide signals to the auxiliary feedwater actuation system (AFWAS).
- Maintain the pressure boundary of the system.
- Maintain electrical continuity or protect the electrical system or both.

In Appendix A to the LRA, the applicant also identified the following intended functions of the FWS based on the requirements of 10 CFR 54.4(a)(3):

- For fire protection—Monitor steam generator level to support safe shutdown in the event of a postulated severe fire.
- For environmental qualification—Maintain functionality of electrical equipment as addressed by the applicant's Environmental Qualification Program, and provide information used to assess the plant and environs condition during and following an accident.
- For SBO—Provide steam generator level indication.

On the basis of the intended functions listed above, the applicant identified 20 device types (or component types) in the FWS that were designated as within the scope of license renewal because they fulfill at least one of the intended functions. Of the 20 device types, the applicant identified 5 that are subject to an AMR: piping, check valves, hand valves, motor-operated valves (MOVs), and temperature elements. The applicant further noted that maintenance of the pressure boundary is the only passive intended function associated with the FWS that is not already addressed by one of the commodity evaluations in other sections of Appendix A to the LRA.

The applicant also stated that some components in the FWS that are common to many systems have been included in the separate commodity report sections of the LRA that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1, "Components Supports," of Appendix A to the LRA;
- Electrical control and power cabling, which is evaluated in Section 6.1, "Cable," of Appendix A to the LRA; and
- Instrument tubing and piping and the associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4, "Instrument Lines," of Appendix A to the LRA.

2.2.3.20.2 Staff Evaluation

The staff reviewed Section 5.9 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the FWS components within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the FWS (NRC letter to BGE dated February 13, 1998), and by letter dated July 30, 1998, the applicant responded to those RAIs.

2.2.3.20.2.1 Feedwater System Within the Scope of License Renewal

During the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the FWS, to determine if there were any system components that the applicant did not identify as within the scope of license renewal but were necessary to perform one of the identified FWS intended functions. The staff also reviewed the design basis for the FWS as described in the UFSAR to determine if there were any additional system functions that were intended functions and, therefore, might require FWS components that the applicant identified as not within the scope of license renewal to be within the scope of license renewal.

The staff's review of the UFSAR and flow diagrams did not uncover any additional structures or components of the FWS that should have been within the scope of license renewal. However, one of the intended functions of the FWS is to isolate feedwater flow to the steam generators. This function is performed by the motor-operated main feedwater isolation valve (MFIV) and associated instrumentation and controls, which are within the scope of license renewal. If the MFIV fails to close on demand, backup isolation is provided by the automatic tripping of the main feedwater pumps, condensate booster pumps, and the heater drain pumps. Section 5.9 of Appendix A to the LRA appeared to only identify the MFIV (and associated instrumentation and controls) as performing this intended function. Therefore, in NRC Question No. 5.9.8 (NRC letter to BGE dated February 13, 1998), the staff asked the applicant to provide justification for excluding the components that perform the backup isolation function. In its response, the applicant stated that it considers the function of steam generator isolation to include the backup means of stopping FWS flow, that is, the tripping of the FWS pumps, condensate booster pumps, and the heater drain pumps. Therefore, in accordance with the scoping process, the applicant determined that any component required to accomplish the tripping function is within the scope of license renewal. The applicant further stated that the only functions performed by the FWS components required to trip the pumps are active and, as such, the components do not require an AMR. The applicant also stated that the cables and other electrical components associated with the intended functions of the FWS are addressed by the commodity reports in Section 6.0 of Appendix A to the LRA. The staff concurs with the applicant's response and did not identify any additional components related to the backup function that should be within the scope of license renewal.

In its review, the staff also did not identify any additional intended functions that could result in additional components (components not identified by the applicant) being within the scope of license renewal and hence, possibly subject to an AMR.

As described above, the staff has reviewed the information presented in Section 5.9 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified those FWS structures and components (device types) within the scope of license renewal in accordance with the requirements in 10 CFR 54.4.

2.2.3.20.2.2 Feedwater System Subject to an Aging Management Review

In Section 5.9.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the feedwater system (FWS) are within the scope of license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.9-1 of Appendix A to the LRA). The staff reviewed all the information presented by the applicant to verify that the applicant's grouping was correct.

The applicant identified 26 device types that need to be consider for an AMR. The staff reviewed all the components within the scope of the rule for the FWS and verified that all the components were considered in these 26 device types. Of 26 device types within the scope of license renewal rule, 22 device types are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit any that should be subject to an AMR. Of the 22 components, the applicant classified the following 15 as having only active functions and, therefore, not requiring an AMR:

- fuse
- power lamp indicator
- pressure indicator
- transformer
- position switch
- hand switch

- level indicator
- relay
- power supply
- current/current device
- level recorder
- temperature relay
- position indicating lamp
- 125 VDC motor
- solenoid valve

Two device types, SG level transmitter and SG pressure transmitter, are either subject to periodic replacement or are evaluated in another AMR. Of the 20 SG level transmitters, 8 are evaluated in Section 4.2.1, "Environmentally Qualified Equipment," of this SER. All remaining SG level and pressure transmitters (pressure boundary only) in the FWS are subject to an AMR and are evaluated in Section 2.2.3.35, "Instrument Lines," of this SER.

Three device types, panel, control/power cabling, and instrument tubing/valves, are evaluated in Section 2.2.3.32, "Cables;" 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrument Lines," in this SER. Two electrical/instrumentation components, MOV and temperature element, evaluated in this section were classified as subject to an AMR (only pressure boundary/body). The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

The staff also reviewed the non-electrical components in the feedwater system in order to determine whether the applicant has properly identified the structures and components subject to an AMR. The staff reviewed the information in Table 5.9-1 of Appendix A to the LRA to ascertain that the applicant has identified all components that are subject to an AMR. The staff found that the applicant had identified all the non-electrical structures and components that perform its intended function without moving parts or without a change in configuration or properties and that are not replaced based on qualified life or specified time period.

The staff has reviewed the information in Section 5.9.1.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified the structures and components in the FWS subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.21 Fire Protection

In Section 5.10 "Fire Protection," of Appendix A to the LRA, the applicant described the systems and the components credited with performing fire protection (FP) functions that are within the scope of license renewal, and identified which of those components are subject to an AMR. By letters dated September 2, September 4, and September 24, 1998, the staff issued requests for additional information (RAIs) regarding the FP systems and components. By letters dated November 16 and December 10, 1998, the applicant responded to those RAIs.

2.2.3.21.1 Summary of Technical Information in the Application

The applicant stated that system level scoping found that of the 122 systems and structures at CCNPP, 66 were within the scope of license renewal. The applicant used the CCNPP FP plan, required in 10 CFR 50.48, "Fire protection," and various licensing-basis documents that addressed the applicant's commitments, as information to prepare the FP screening tool described in Section 2.0 of Appendix A to the LRA.

The FP screening tool defines two categories of FP functions. The first category is the FP function, which includes equipment and facilities important to safety that provide for detecting, fighting, and extinguishing fires. This equipment and these facilities are necessary to protect safety-related (SR) equipment and structures from fire or explosion. This function does not include FP equipment or facilities protecting NSR equipment and structures. The second category is the safe shutdown function, which applies to systems that provide for safe shutdown of the plant in the event of a severe fire. Therefore, the evaluations pertaining to safe shutdown identified those components that are required for compliance with these regulations. The safe-shutdown function includes the capability to provide the following:

- reactor coolant system (RCS) pressure and inventory control;
- reactivity control;
- heat removal (hot standby or cold shutdown) from the RCS; and
- process monitoring.

For the 66 systems and structures that the applicant identified during the system-level scoping as within the scope of license renewal, those with FP functions were identified using the FP screening tool. The FP screening tool showed that 42 of the 66 systems and structures within the scope of license renewal have one or more FP-intended functions. Of the 42 systems and structures identified in Table 5.10-1 of Appendix A to the LRA, the applicant evaluated 26 of these SR systems and structures within their respective sections of the LRA. These systems and structures fall into one of the three following categories and are not discussed further in Section 5.10 of Appendix A to the LRA:

- structures with components that provide a fire barrier;
- fluid systems with components that provide part of a pressure boundary (PB) in systems with only safety-related (SR) PB components; and
- electrical systems with components that perform only active electrical functions.

Of the 26 systems and structures identified, 5 structures with components that provide a fire barrier are addressed in Sections 3.3A, 3.3B, 3.3C, and 3.3E of Appendix A to the LRA. Eight fluid systems with components that provide part of a pressure boundary (PB) in systems with only SR PB components are addressed in Sections 5.6, 5.8, 5.9, 5.11A, 5.11B, 5.11C, 5.15, and

5.16 of Appendix A to the LRA. Finally, there are 13 electrical systems with components that perform FP-intended functions. Those systems require no further evaluation in Section 5.10 because their FP intended functions are addressed in other commodity evaluations.

The remaining 16 systems and structures are within the scope of license renewal, and are addressed in Section 5.10 of Appendix A to the LRA. Nine of the remaining systems and structures that perform FP-intended functions have both SR and NSR PB components. The applicant addressed the SR portions of these systems and structures in Sections 4.1, 5.1, 5.2, 5.3, 5.4, 5.7, 5.12, and 5.17 of Appendix A to the LRA. The applicant addressed the NSR PB portions of these systems and structures in Section 5.10 of Appendix A to the LRA. Seven of the remaining systems and structures rely almost entirely on NSR components to perform their FP-intended functions. The applicant addressed these in Section 5.10 of Appendix A to the LRA.

For some of the systems and structures with FP-intended functions, the applicant performed component-level scoping in two ways. The applicant either produced a detailed list of components that contribute to an intended function of the system or structure, or defined a boundary (or envelope) of the important pressure-retaining features of the system in terms of major components or interfaces with other systems, and identified the specific device types that fell within that boundary (or envelope).

The applicant also indicated that, in separate commodity reports, it included some components with FP functions that are common to many systems. These reports address those components for the entire plant. Therefore, the following components were not included in the individual systems and structure sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;
- Electrical control and power cabling, which are evaluated in Section 6.1 of Appendix A to the LRA;
- Electrical panels that support and/or protect electrical components, which are evaluated in Section 6.2 of Appendix A to the LRA; and
- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.21.2 Staff Evaluation

The Commission's regulations in 10 CFR 54.4(a)(3) define all systems, structures, and components relied upon in safety analyses or plant evaluations to demonstrate compliance with

10 CFR 50.48 (the NRC regulation governing fire protection) as included within the scope of license renewal.

The Commission's regulations in 10 CFR 54.21(a)(1) state that for those systems, structures, and components within the scope of this part, as delineated in 10 CFR 54.4, the integrated plant assessment (IPA) must identify and list those structures and components subject to an AMR. The staff reviewed Section 5.10 of Appendix A to the LRA, as supplemented by letters dated November 16 and December 10, 1998, and the other documentation discussed below, to determine whether there is reasonable assurance that the applicant has appropriately identified the components and supporting structures that serve FP-intended functions, and are within the scope of license renewal in accordance with 10 CFR 54.4 and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.21.2.1 Fire Protection Within the Scope of License Renewal

This evaluation is to determine whether the applicant has properly identified the systems, structures, and components within the scope of license renewal, pursuant to 10 CFR 54.4. As described in more detail below, the staff reviewed selected structures and components that the applicant did not identify as within the scope of license renewal to verify that they do not have any intended function.

As part of the evaluation, the staff reviewed portions of the UFSAR concerning the FP system and made a comparison between the diagrams in Appendix A to the LRA as supplemented and Section 9.9 of the UFSAR "Calvert Cliffs Nuclear Power Plant Fire Protection Program," to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. In Section 5.10 of Appendix A to the LRA, the applicant stated that 66 systems and structures were within the scope of license renewal. The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from the scope of the rule. On the basis of its review, the staff found no omissions.

The applicant applied its FP screening tool to the 66 systems and structures within the scope of license renewal, and credited 42 systems and structures with performing FP functions. The staff sampled portions of the 24 systems and structures without FP functions to verify that the tool properly screened systems and structures with FP functions. For example, the staff reviewed the information in Section 9.7, "Spent Fuel Pool Cooling and Storage," of the UFSAR and found that the system has no intended functions for FP. The staff found no omissions of systems or structures with FP-intended functions in the sample.

Of the 42 systems and structures performing FP-intended functions, 26 are SR systems and structures evaluated elsewhere in the LRA by the applicant. The staff sampled several of these systems and structures and found that FP-intended functions were identified as system intended functions in the referenced sections. Table 1 lists the 26 systems and the location of the evaluations in the LRA.

Table 1 Systems and Structures Addressed Outside of Section 5.10 of Appendix A to the LRA

System	LRA Section*	System	LRA Section*
Intake Structure	3.3C	Electrical 125-V dc Distribution	Addressed in commodity evaluations
Primary Containment	3.3A	Electrical 4-kV Transformers and Buses	Addressed in commodity evaluations
Barriers/Barrier Penetrations	Addressed as part of structures in Sections 3.3A/B/C/E	Electrical 480-V Transformers and Buses	Addressed in commodity evaluations
Auxiliary Building	3.3E	Instrument AC	Addressed in commodity evaluations
Turbine Building	3.3B	Vital Instrument AC	Addressed in commodity evaluations
Saltwater	5.16	Annunciation	Addressed in commodity evaluations
Emergency Diesel Generators	5.8	Control Rod Drive Mechanism and Electrical	Addressed in commodity evaluations
Control Room HVAC	5.11C	Nuclear Instrumentation	Addressed in commodity evaluations
Auxiliary Building and H&V	5.11A	Main Turbine	Addressed in commodity evaluations
Feedwater	5.9	Fire and Smoke Detection	Addressed in commodity evaluations
Safety Injection	5.15	Lighting and Power Receptacles	Addressed in commodity evaluations
Primary Containment H&V	5.11B	Plant Communications	Addressed in commodity evaluations
Containment Spray	5.6	Electrical 480-V Motor Control Centers	Addressed in commodity evaluations

*In Appendix A to the LRA

The remaining 16 systems within the scope of license renewal are addressed in Section 5.10 of Appendix A to the LRA. The staff verified that they were required by the FP plan because they meet at least one FP-intended function. Nine of these systems perform passive FP-intended functions and have both SR and NSR PB components. The SR portions of these nine systems are addressed in other sections of Appendix A to the LRA, while the NSR portions of these systems are addressed in Section 5.10 of Appendix A to the LRA. The other seven systems rely almost entirely on NSR components to perform their FP-intended functions and are entirely addressed in Section 5.10. Table 2 lists the 16 systems that have NSR components and structures that perform FP-intended functions. For the nine systems that have SR components or structures that perform FP-intended functions, Table 2 provides a reference to the appropriate sections of Appendix A to the LRA where the structure or component is evaluated.

Table 2 Systems and Structures Addressed in Section 5.10 of Appendix A to the LRA (NSR PB portions only)

System	LRA Section *	System	LRA Section*
Service Water	5.17 (SR portion) 5.10 (NSR portion)	Main Steam	5.12 (SR portion) 5.10 (NSR portion)
Component Cooling	5.3 (SR portion) 5.10 (NSR portion)	Well and Pretreated Water	5.10
Compressed Air	5.4 (SR portion) 5.10 (NSR portion)	Liquid Waste	5.10
Diesel Fuel Oil	5.7 (SR portion) 5.10 (NSR portion)	Fire Protection	5.10
Auxiliary Feedwater	5.1 (SR portion) 5.10 (NSR portion)	Plant Heating	5.10
Chemical and Volume Control	5.2 (SR portion) 5.10 (NSR portion)	Demineralized Water and Condensate Storage	5.10
Reactor Coolant	4.1 (SR portion) 5.10 (NSR portion)	Condensate	5.10
Nitrogen and Hydrogen Gas System	5.12 (SR portion) 5.10 (NSR portion)	Plant Drains	5.10

*In Appendix A to the LRA

To help ensure that the applicant had appropriately identified all FP-intended functions, the staff asked the applicant to clarify how it had applied its FP screening tool. NRC Question

No. 5.10.6 asked the applicant to verify that it had captured changes to such documents as the Interactive Cable Analysis, and other FP program documentation, to form the FP screening tool. The applicant assured the staff that it had updated the FP screening tool, and that it had used the latest versions of licensing documents in its formulation. The staff reviewed the applicant's response and did not find any omissions of FP functions by the applicant.

However, during the review of Section 5.17 of Appendix A to the LRA, the staff found that nozzles that perform a dousing function for the charcoal beds were not included within the scope of license renewal and were not subject to an AMR. This issue was being tracked by Open Item No. 2.2.3.17.2.1-1 and further discussion of its closure is provided in Section 2.2.3.17.2.1 of this SER.

As described above, the staff has reviewed the information submitted in Section 5.10 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of its review the staff concludes there is reasonable assurance that the applicant has appropriately identified the portions of the FP program that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.21.2.2 Fire Protection Subject to an Aging Management Review

After the staff determined which structures and components were within the scope of license renewal, the staff determined whether the applicant properly identified the structures and components subject to an AMR from among those identified as being within the scope of license renewal. The staff reviewed selected structures and components that the applicant identified as being within the scope of license renewal to verify that the applicant has identified these structures and components as subject to an AMR if they perform intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement based on a qualified life or specified time period.

In a letter dated November 20, 1996, the staff informed the applicant that as an acceptable method of component-level scoping, identification of systems and components subject to review must enable the staff to readily determine from onsite drawings or lists whether a particular system or component is subject to an AMR. In the LRA, for most systems and structures within the scope of license renewal, the applicant submitted a detailed list of components contributing to an intended function of the system or structure. For the systems with passive NSR FP-intended functions, component-level scoping was performed by defining the boundary (or envelope) of the important pressure-retaining features of the system in terms of major components or interfaces with other systems, and by identifying the specific device types that fell within that boundary (or envelope) in Section 5.10 of Appendix A to the LRA. Using this method, the FP components subject to an AMR in Section 5.10 of Appendix A to the LRA can be readily determined from review of the drawing references, which meets the criteria stated in the November 20, 1996, letter.

Table 3 identifies the portions of the 16 systems that have passive, long-lived NSR FP components and structures performing FP-intended functions. The passive FP-intended functions for the 16 systems, not evaluated in other sections, consist of maintaining the pressure boundary of the system liquid or gas, and providing drainage of fire-fighting water in rooms containing SR equipment. The portions of the 16 systems identified in Table 3 below are subject to an AMR. All other portions of these systems used for FP-intended functions are SR and addressed elsewhere in the LRA as discussed in Section 2.2.3.21.2.1 of this SER.

Table 3 Summary of FP Structures and Components Evaluated for AMR in Section 5.10 of Appendix A to the LRA (NSR Portion, Only)

System	NSR Portion of System Within the Scope of LR and Subject to an AMR	Passive FP-intended Function (not addressed in other evaluations)
Well and Pretreated Water	Components in the flow path from the well water pumps to the Primary Water Storage Tanks and the associated pretreated water booster pumps	Maintain pressure-retention capability of the system (liquid/gas)
Service Water	Components that retain pressure in the cooling process flow paths to the instrument air and plant air compressors	Maintain the PB of the system liquid
Fire Protection	Pressure-retaining fire-fighting equipment that performs an FP-intended function or a safe shutdown intended function	Maintain pressure-retaining capability of the system (liquid/gas)
Component Cooling	Components in the head tank makeup flow paths and the flow paths to and from the reactor coolant waste evaporator	Maintain the PB of the system liquid
Compressed Air	All NSR components of the system	Maintain the PB of the system (liquid/gas)
Diesel Fuel Oil	NSR piping and components related to the diesel-driven fire pump	Maintain the PB of the system liquid
Plant Heating	NSR components in the main process flow paths shown as normally open on the system drawings	Maintain the PB of the system (liquid/gas)
Auxiliary Feedwater	The AFW spool piece for the fire hose connections, AFW isolation valves from CSTs 11 and 21, and the piping between the isolation valves and the CSTs	Maintain the PB of the system (liquid/gas)

System	NSR Portion of System Within the Scope of LR and Subject to an AMR	Passive FP-intended Function (not addressed in other evaluations)
Demin. Water and Condensate Storage	Limited to CSTs 11 and 21, associated level instruments, emergency hose connections, and all pressure-retaining piping and components up to the first isolation valve on all headers to and from the tanks	Maintain the PB of the system (liquid/gas)
Chemical and Volume Control	Limited to the NSR piping and valves that constitute the flow path from the reactor coolant pump controlled bleedoff lines to the letdown subsystem	Maintain the PB of the system (liquid/gas)
Condensate	Components in the makeup flow path to the SRW and CC head tanks from the fire hose connection	Maintain the PB of the system (liquid/gas)
Plant Drains	Piping and valves in the floor drain lines from rooms containing SR equipment	(1) Maintain pressure-retaining capability of the system (liquid/gas) (2) Provide drainage of fire-fighting water in rooms containing SR equipment
Reactor Coolant	Piping and associated components in the controlled bleedoff lines from the reactor coolant pumps to the CVCS	Maintain the PB of the system (liquid/gas)
Liquid Waste	Components in the flow paths from the sump pump discharge check valves serving areas containing SR equipment to the waste processing subsystems	(1) Maintain the PB of the system (liquid/gas) (2) Provide drainage of fire-fighting water in rooms containing SR equipment
Nitrogen and Hydrogen	Limited to the NSR excess flow check valves	Maintain pressure-retaining capability of the system gas
Main Steam	Pressure-retaining piping and components located downstream of the MSIVs up to the next isolation valves, i.e., turbine bypass valves, moisture separator reheater isolation valves, main turbine stop valves, main feed pump turbine stop valves, and steam seal isolation valve	Maintain the PB of the system (liquid/gas)

Structures and Components Subject to an Aging Management Review

To verify whether the applicant had properly identified the structures and components subject to an AMR from among the structures and components with NSR FP-intended functions that have been identified as within the scope of license renewal, the staff performed the following review. The applicant identified structures and components as subject to an AMR if they perform their intended functions without moving parts or without a change in configuration or properties, and are not subject to replacement on the basis of a qualified life or specified time period. The staff compared the information in the UFSAR with the information in the application for selected structures and components. Specifically, the staff reviewed the flow diagrams in Figures 9-6 and 9-25 of the UFSAR for the component cooling system and the CVCS, and Figures 9-23 and 9-28 of the UFSAR for the compressed air system to verify which portions of the system were subject to an AMR. On the basis of the findings of this review and the description of the systems found in Section 5.10 of Appendix A to the LRA, the staff found no omissions of long-lived, passive structures or components within the scope of license renewal that are subject to an AMR. Therefore, the staff has reasonable assurance that the applicant identified all passive, long-lived NSR structures and components with FP-intended functions that are subject to an AMR.

The staff has reviewed the information in Section 5.10 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of its review of selected structures and components, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components for the FP program to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.22 Auxiliary Building Heating and Ventilation System

In Section 5.11A, "Auxiliary Building Heating and Ventilation System (ABHVS)," of Appendix A to the LRA, the applicant described portions of the ABHVS and the components therein that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.22.1 Summary of Technical Information in the Application

The ABHVS consists of fans, air handling units, dampers, filters, coolers, controls, and ductwork that provide air, in some cases filtered and tempered, to various rooms in the auxiliary and radwaste buildings. A negative pressure, with respect to ambient conditions in surrounding spaces, is normally maintained in the auxiliary building to ensure that clean areas do not become contaminated through the ventilation system. Areas serviced by the system are the switchgear rooms (each unit), diesel generator rooms (three total), auxiliary feedwater (AFW) pump room (each unit), service water (SRW) heat exchanger room (each unit), main steam line penetration area (each unit), waste processing area (each unit), emergency core cooling system (ECCS) pump rooms (each unit), the fuel handling areas (shared between units), and general areas of the auxiliary building. Exhaust air from the waste processing areas, ECCS pump rooms, and the fuel handling areas is passed through a roughing filter and a high-efficiency particulate air (HEPA) filter to remove potentially radioactive particulate contamination preceding discharge through the plant vent. Exhaust air from the ECCS pump room and the fuel handling area can also be routed through separate charcoal filters to remove radioactive iodine in the event of a loss-of-coolant accident or fuel handling incident, respectively.

The air in the switchgear rooms is temperature controlled the year round by redundant heating, ventilating, and air conditioning (HVAC) units and refrigeration systems. The HVAC units and refrigeration components are redundant, but the supply and return ducts to the switchgear rooms are not.

The ventilation system for the auxiliary building areas in which the Fairbanks Morse diesel generators are housed is designed to limit room temperature to a maximum of 120 °F in summer and a minimum of 60 °F in winter. When the emergency diesel generator (EDG) is running, its room is pressurized and the excess air is forced out through a weatherproof exhaust opening over the outside door. Hot water unit heaters maintain a minimum temperature of 60 °F when the diesel generator is shut down.

There are "normal" and "emergency" air cooling systems for the AFW pump room. During normal plant operation, one self-contained HVAC unit maintains the temperature in this room at 90 °F or below. During the emergency mode of operation, redundant fans circulate air between the AFW pump room and the fan equipment room through a system of connecting ductwork, and the rooms are maintained at 120 °F or below. The SRW heat exchanger room is provided with forced air ventilation by separate supply and exhaust fans and dampers to maintain the room temperature low enough for equipment operability in post-accident situations. The main steam pipe tunnel between the MSIV room and the turbine building is cooled by fans that force air from the turbine building into the main steam pipe tunnel.

The waste processing area in the auxiliary building is maintained at a negative pressure with respect to ambient conditions in surrounding spaces. A common air supply system, consisting of three 50 percent capacity air handling units, supplies outdoor air for ventilation of the common waste processing area. The exhaust system draws air from the waste processing areas and forces it through the HEPA filter bank, to the main exhaust plenums. The plant's redundant main exhaust fans force the air past the radioactivity monitors and out through the exhaust stacks.

The ECCS pump rooms are served by a ventilation subsystem to control room temperature and provide proper cooling of the safety injection and containment spray pumps. The subsystem consists of one cooling unit for each ECCS pump room, cooling unit fans, and an ECCS pump room exhaust system that contains a roughing filter, a HEPA filter, a charcoal filter, and dampers. Saltwater is circulated through the air cooling coils to remove heat.

Two 50-percent-capacity air handling units provide filtered air to the fuel handling area. A separate exhaust system draws air through a manifold and HEPA filters and feeds it into the main plant vent of Unit 1. During the movement of fuel over the spent fuel pool, air from the fuel handling area is diverted through charcoal filters after it leaves the HEPA filters to minimize the release of radioactive material in the event of a fuel handling accident. The exhaust fans are capable of maintaining a negative pressure with respect to ambient conditions in surrounding spaces of the building. Unit heaters maintain a minimum temperature of 60 °F in the winter.

In the LRA, the applicant identified the following intended functions for the ABHVS based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- To supply air to the battery ventilation system in response to a design basis event (DBE);
- To initiate letdown line isolation to provide radiological release control during a loss-of-coolant accident;
- To provide ventilation for, and remove potentially radioactive contaminated air from, the ECCS pump room in response to a DBE;
- To provide HVAC for, and remove potentially radioactive contamination from, the fuel handling area in response to a DBE;
- To provide HVAC to the electrical switchgear room in response to a DBE;
- To provide ventilation to the diesel generator rooms in response to a DBE;
- To provide ventilation to the AFW pump room in response to a DBE;
- To provide ventilation to the SRW heat exchanger room in response to a DBE;
- To maintain electrical continuity and/or provide protection of the electrical system;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To maintain structural integrity to support proper operation of other ABHVS components.

The following ABHVS intended functions were determined on the basis of the requirements of 10 CFR 54.4(a)(3):

- For fire protection (10 CFR 50.48)—To provide alternate ventilation to the AFW pump room during a fire, and

- For environmental qualification (10 CFR 50.49)—To maintain functionality of electrical equipment as addressed by the environmental qualification program and to provide information used to assess the plant and environs condition during and following an accident.

On the basis of the intended functions stated above, the portions of the ABHVS that are identified by the applicant as within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument) and their supports. The applicant identified a total of 46 device types as within the scope of license renewal. Of these 46 device types, the applicant identified 9 that are subject to an AMR. The 9 device types are damper, HVAC duct, fan, filter, gravity damper, manual damper, hand valve, heat exchanger, and pressure differential indicator. The applicant also indicated that the ABHVS pressure boundary is the only passive intended function associated with the ABHVS that is not addressed in one of the commodity evaluations in the LRA. Therefore, only the pressure-retaining function for the 9 device types subject to an AMR was considered.

The applicant also indicated that some components that are common to many systems have been included in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;

- Electrical control and power cabling, which is evaluated in Section 6.1 of Appendix A to the LRA; and

- Process and instrument tubing and tubing supports, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.22.2 Staff Evaluation

The staff reviewed Section 5.11A of Appendix A the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the ABHVS components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4, and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the ABHVS (NRC letter dated September 4, 1998), and by letter dated November 16, 1998, the applicant responded to the RAIs.

2.2.3.22.2.1 Auxiliary Building Heating and Ventilation System Within the Scope of License Renewal

The staff reviewed portions of the UFSAR, including Section 9.8, "Plant Ventilation Systems," to determine if there were any portions of the system that the applicant did not identify as within the scope of license renewal that should have been so identified. The staff also reviewed Section 9.8 of the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA, and to determine if there were structures and components having intended functions that might have been omitted from consideration within the scope of license renewal. The staff also reviewed the system to determine if any structures or components not identified in the LRA as within the scope of the rule should have been so identified under 10 CFR 54.4(a)(2) or 54.4(a)(3). The staff compared the safety-related functions described in the UFSAR to those identified in the LRA.

To help ensure that those portions of the ABHVS identified as not within the scope of license renewal did not perform any intended functions and, therefore, would not be subject to an AMR, the staff requested additional information from the applicant based on the information in the UFSAR and the LRA. In NRC Question No. 5.11.2, the staff noted that Section 5.11A.1.1 in "System Level Scoping" summarizes the system boundaries and components within the scope of license renewal for the ABHVS. The drawings showing the system scoping boundaries were not included. The corresponding drawings for these systems in the UFSAR for CCNPP are not detailed enough for the staff to clearly understand the system renewal scope. By a letter dated November 16, 1998, the applicant sent Figure 5.11A-1 showing the scoping boundaries for the ABHVS. On the basis of the applicant's response that included a drawing showing the correct scoping boundaries, the staff agrees that the applicant identified the system level scoping boundaries, and that those LRA boundaries correctly separate system components within these boundaries from those that are outside.

As described above, the staff has reviewed the information submitted in Section 5.11A of Appendix A to the LRA and the applicant's response to the staff's RAI. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the ABHVS and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.22.2.2 Auxiliary Building Heating and Ventilation System Subject to an Aging Management Review

On the basis of the intended system functions listed above, the applicant emphasized that the portions of the ABHVS system that are within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrumentation) and their supports. The applicant described the subsystems and such associated devices as accumulators, check valves, and dampers. The applicant identified 46 device types. Of the 46 device types associated with the ABHVS system the applicant identified 25 device types that have only active functions and do not require an AMR. Of the 46 device types, 10 do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly. These complex assemblies perform their intended functions with moving parts. These 10 device types are piece-parts of the mechanism, and therefore, are not subject to an AMR, and two of them (panels and pressure differential indicator switches) are evaluated in other sections of Appendix A to the LRA. As a result of this screening process, all components of the remaining 9 device types are subject to a detailed evaluation of aging mechanisms as part of an AMR: damper, HVAC duct, fan, filter, gravity damper, manual damper, hand valve, heat exchanger, and pressure differential indicator.

Of the device types (including the three electrical/instrumentation device types discussed below) within the scope of the license renewal rule, 32 are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 32 device types, the applicant classified the following 23 as having only active functions and, therefore, not requiring an AMR:

- disconnect switch/link
- fuse
- hand switch
- converter/relay
- power lamp indicator
- level device (relay)
- 480-V motor (feed from MCC)
- 480-V motor
- 125/250-V dc motor
- temperature device (relay)
- pressure transmitter
- relay
- position controller
- temperature transmitter
- control valve
- pressure converter (relay)
- temperature controller
- position switch
- temperature element
- temperature switch
- motor operator
- temperature indicating controller
- position indicating lamp

Four device types (pressure indicator, pressure switch, temperature control valve, and solenoid valve) do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly whose only passive function is closely linked to active performance of the refrigeration units.

Three device types (electrical control/power cabling, instrument tubing/valves, and pressure differential indicator switch) are evaluated in Section 2.2.3.32, "Cables," and Section 2.2.3.35, "Instrument Lines," of this SER. The remaining two electrical/instrumentation components (fan and pressure differential indicator) evaluated in this section are classified as subject to an AMR.

The staff has reviewed the information in Section 5.11A of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified the

ABHVS system structures and components subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.23 Primary Containment Heating and Ventilation System

In Section 5.11B, "Primary Containment Heating and Ventilation (H&V) System," of Appendix A to the LRA, the applicant described portions of the primary containment H&V system and the components therein that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.23.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the primary containment H&V system is designed to remove heat from the containment atmosphere during normal plant operations and accident conditions via the containment air recirculation and cooling subsystem. The subsystem is independent of the containment spray and safety injection systems. The subsystem for each unit consists of four cooling units, an air mixing plenum, and the distributing ductwork and piping, all located inside the containment. Service water is circulated through the air cooling coils to remove heat.

In the LRA, the applicant identified the following intended functions for the primary containment H&V system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Control containment temperature and pressure;
- Provide containment atmosphere filtration and radiation control;
- Collect and process containment penetration leakage into the penetration rooms;
- Filter hydrogen purge air for radiation control following DBEs;
- Measure pressure in the containment penetration rooms;
- Provide containment atmosphere pressure source to ESFAS instrumentation for protective actuation;
- Isolate the containment;
- Maintain electrical continuity and provide protection or both of the electrical system;
- Maintain the pressure boundary of the system; and
- Provide seismic integrity and protection or both of safety-related components.

The applicant also determined that the following were intended functions of the primary containment H&V system based on the requirements of 10 CFR 54.4(a)(3):

- For post-accident monitoring—Provide information used to assess the condition of the plant and its environs during and following an accident, and
- For equipment qualification—Maintain functionality of electrical components as addressed by the EQ program.

On the basis of the intended functions stated above, the portions of the primary containment H&V system that are identified by the applicant as within the scope of license renewal are all safety-related components in the system (electrical, mechanical, and instrument) and their supports. The applicant listed 38 device types that are within the scope of license renewal. It also identified 3 additional primary containment H&V system device types (panels, cables, and instrument lines) that are evaluated by the applicant in Sections 6.1, 6.2, and 6.5 of Appendix A to the LRA. Of these 41 device types, the applicant identified 12 that are subject to an AMR. The 12 device types are piping (Code HB), five valve types (check, control, motor operated, solenoid, and hand valve), damper, duct, fan, filter, gravity damper, and heat exchanger. The applicant further indicated that containment and system pressure boundary integrity are the only passive intended functions associated with the primary containment H&V system that are not addressed in one of the commodity evaluations of the LRA. Therefore, only the pressure-retaining function for the 12 device types subject to an AMR was considered.

The applicant also stated that some components in the primary containment H&V system that are common to many systems have been evaluated in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components that are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;
- Electrical control and power cabling that is evaluated in Section 6.1 of Appendix A to the LRA; and
- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.23.2 Staff Evaluation

The staff reviewed Section 5.11B of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the primary containment H&V system components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4, and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the primary containment H&V system (NRC letter to BGE dated September 2, 1998), and by letter dated November 16, 1998, the applicant responsed to those RAIs.

2.2.3.23.2.1 Primary Containment Heating and Ventilation System Within the Scope of License Renewal

The staff reviewed portions of the UFSAR, including Section 6.5, "Containment Air Recirculation and Cooling System," and compared them to the diagrams in Appendix A to the LRA to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. The staff also reviewed Section 6.5 of the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from the scope of license renewal.

Section 6.5.4 of the UFSAR describes piping that transfers the condensate leaving the coils to the containment sump. The staff asked the applicant (NRC Question No. 5.11.4) to provide the basis for excluding this piping from the scope of license renewal. In response to NRC Question No. 5.11.4, the applicant stated that in the event the drainage lines fail, the condensate would drain from the main sump of the cooling coil housing directly onto the containment floor and eventually to the sump. The cooling coil units would still be able to perform their intended function. Additionally, in response to the staff's desire to clarify the applicant's response to NRC Question No. 5.11.4, during a December 9, 1998, teleconference, the applicant verified that containment air cooler condensate was not credited as fluid available for recirculation. The credited volume of fluid in the containment at the time of recirculation is equal to the sum of the minimum usable refueling water tank volume and the minimum usable volume of the four safety injection tanks. On the basis of the applicant's response, which is summarized in the NRC meeting summary dated March 19, 1999, the staff agrees that the non-safety-related drainage lines do not perform any of the system- intended functions as defined in 10 CFR 54.4(a)(1), (2), and (3), and are not within the scope of license renewal.

Section 5.11B.1.2 in Appendix A to the LRA states that ductwork downstream of the fusible links is not within the scope of license renewal. The containment air recirculation and cooling system provides cooling air via this ductwork to the SG compartment and reactor vessel annulus. As a result, the staff questioned whether the ductwork should be within the scope of license renewal. To clarify the staff's question, a conference call was made on December 9, 1998 to the applicant's staff. In response to the call, the applicant stated that cooling via this ductwork was credited in the long-term thermal aging analysis, which supports the applicant's EQ program. Because the staff was considering whether non-safety-related support systems, such as ductwork, credited in analyses that support programs such as EQ, are within the scope of license renewal, this was identified as Open Item 2.2.3.23.2.1-1 in the previous SER.

By letter dated September 28, 1999, the applicant stated that the failure of ductwork, which contributes to providing the normally expected environments, will not prevent the execution of the critical safety functions identified in 10 CFR 50.49(b)(1) during and following a design basis accident. In addition, the applicant stated that during or following a design basis accident, the cavity cooling function is assumed to be unavailable. The applicant added that any failure of the cavity cooling system, or any of its components, would be treated as a degraded condition and operability of the affected system, structure, or component would be evaluated, including affects on 10 CFR 50.49(b) equipment.

In a letter to the Nuclear Energy Institute dated August 5, 1999, the NRC staff issued additional guidance to identify SSCs within the scope of license renewal under 10 CFR 54.4. In this letter, the staff concluded that, based on the applicant's current licensing basis, those SSCs required to comply with, and operate within, the Commission's regulations, identified in 10 CFR 54.4(a)(3), need to be considered.

Since the applicant stated that the failure of the cavity cooling system ductwork will not prevent the satisfactory completion of any critical safety function during and following a design basis accident, the ductwork is not required to be within the scope of license renewal. Therefore, Open Item 2.2.3.23.2.1-1 is closed.

As described above, the staff has reviewed the information in Section 5.11B of Appendix A to the LRA, the additional information documented in the NRC meeting summary dated March 19, 1999, and the applicant's response to the staff's RAIs. On the basis of the review discussed above, the staff finds reasonable assurance that the applicant has appropriately identified the portions of the primary containment H&V system and the associated structures and components thereof, that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.23.2.2 Primary Containment Heating and Ventilation System Subject to an Aging Management Review

The applicant applied a scoping process as delineated in Section 2.0 of Appendix A for identifying device types subjected to an AMR for the primary containment H&V system. The applicant listed 38 device types that are within the scope of license renewal. They also identified 3 additional primary containment H&V system device types (component supports, cables, and instrument lines) that are evaluated by the applicant in Sections 3.1, 6.1, and 6.4 of Appendix A to the LRA. Of the 41 device types, 21 were determined to perform their intended function with moving parts or with a change in configuration or properties and did not require an AMR. Eight device types were evaluated in other sections of the LRA. The remaining 12 device types, which were determined to require an AMR, are check valve, control valve, damper, HVAC duct, fan, filter, gravity damper, piping (Code HB), hand valve, heat exchanger, motor-operated valve, and solenoid valve.

Structures and Components Subject to an Aging Management Review

The staff reviewed all the information submitted by the applicant and verified that the applicant identified all structures and components of the primary containment H&V system within the scope of the rule as required under 10 CFR 54.4(a). Of the total 41 device types within the scope of the license renewal rule, 30 device types are electrical/instrumentation components. The staff reviewed these device types to determine which electrical/instrumentation components should be subject to an AMR. Of these electrical/instrumentation components, the applicant classified the following 19 as having only active functions and, therefore, not requiring an AMR:

- coil
- voltage/current device
- fuse
- hand switch
- ammeter
- 480-V motor
- 125/250-V dc motor
- MOV operator
- pressure-indicating alarm
- pressure indicator
- pressure-indicating differential
- relay
- temperature element
- temperature indicator
- power supply
- position indicating lamp
- position switch
- 480-V motor (feed from MCC)
- power lamp indicator

The staff agrees with the applicant's determination that these device types perform their functions with moving parts or with a change in configuration or properties.

The following 11 electrical/instrumentation device types are subjected to an AMR:

- disconnect switch/link
- 480 V control station
- pressure differential indicator switch
- pressure transmitter
- control valves
- MOVs
- disconnect switch/link
- 480-V control station
- pressure differential indicator switch
- pressure transmitter
- solenoid valves

Of the 11 device types, 8 (disconnect switch/link, 480-V control station, pressure differential indicator switch, pressure transmitter, disconnect switch/link, 480 V control station, pressure differential indicator switch, and pressure transmitter) are evaluated in Section 6.1, "Cable"; Section 6.2, "Electrical Commodities"; or Section 6.4, "Instrumentation Line," of the application. The 3 remaining electrical/instrumentation components device types (control valve, MOV, and solenoid valve) are evaluated in this section.

The staff also reviewed the 11 non-electrical device types. Of these 11 device types, 2 device types (piston operators and hydrogen recombiners) were determined to require a moving parts, or a change in configuration or properties. The remaining 9 non-electrical device types (check valves, dampers, duct, fan, filter, gravity damper, piping, hand valves, and heat exchangers) were determined to require an aging management review.

The staff asked a number of questions related to the exclusion of certain components (e.g., the fusible link associated with the containment air cooler blowdown door [NRC Question No. 5.11.3], and electric hydrogen recombiners [NRC Question Nos. 5.11.6 and 5.11.7]) from an AMR. The applicant explained that such components were excluded for one of the following reasons: (1) they were active components, and were not within the scope of license renewal, (2) they were not safety-related, and did not affect the functioning of other safety-related structures, systems, and components, or (3) they were evaluated in other sections of Appendix A to the LRA. The staff reviewed the applicant's justification and determined that it was consistent with the requirements in 10 CFR 54.21(a)(1). The staff finds the determination of the primary containment H&V system non-electrical device types subject to an AMR consistent with the requirements in 10 CFR 54.21(a)(1).

The staff reviewed the information in Section 5.11B of Appendix A to the LRA and additional information submitted by the applicant in response to applicable RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components in the primary containment H&V system subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.24 Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems

In Section 5.11C of Appendix A to the LRA, the applicant identified portions of the CRHVACS and DGBHVACS and the components therein that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.24.1 Summary of Technical Information in the Application

The CRHVACS provides ventilation to the control room, the Units 1 and 2 cable spreading rooms, and the Units 1 and 2 battery rooms. The control room and cable spreading rooms are supplied by a single, year-round air conditioning system serving Units 1 and 2. Air handling equipment and refrigeration units are redundant, but the ductwork is not. The control room and cable spreading room areas have a third source of cooling, which is not safety-related, in the form of a water chiller supplying a second set of coils in the safety-related air handling systems. If airborne contamination occurs at the fresh-air intake, a self-contained recirculation system is automatically initiated through a post-LOCA filter system. The control room air is then processed through HEPA and charcoal filters. The air conditioning system is divided into three supply and return duct systems: one for each of the two cable spreading rooms and one for the control room. Each branch contains isolation dampers that are automatically closed if smoke is detected within the branch. The remaining branches continue to serve the other two zones without interruption.

Smoke can be evacuated from the isolated zone by means of an auxiliary fan, motorized dampers, and an outside-air intake. The battery rooms are separately ventilated. Heated and filtered air is supplied to the four battery rooms and the reserve 125-V dc battery room on the 27-foot and 45-foot levels of the auxiliary building, using one supply fan, one exhaust fan, a heating coil, a roughing filter, and motor-operated dampers. Separate supply and exhaust fans are utilized to maintain a negative pressure in these rooms, with respect to the surrounding areas, to preclude the hydrogen concentration in the air from reaching the explosive limit. Upon loss of either fan, sufficient ventilation is provided by the remaining fan to preclude the possibility of hydrogen accumulation within the battery rooms.

As described in the LRA, the DGBHVAC provides ventilation, heating and cooling for the buildings in which two new diesel generators are located. These two new diesel generators were placed into operation in 1995. Because of the unusual circumstances pertaining to these HVAC systems (i.e., they were placed into service approximately 20 years after other similar HVAC systems at CCNPP, and they have a design life of 45 years), an AMR process separate and unique from that used for other plant systems and structures was used. Since aging of the existing control room HVAC system equipment is some 20 years ahead of the aging of the HVAC system equipment in the diesel generator buildings, and since this equipment is just at the beginning of its design life, aging management of the new equipment can be deferred and then be based on future results of aging management from similar equipment groups associated with the control room HVAC system.

In the LRA, the applicant identified the following intended functions for the CRHVACS on the basis of 10 CFR 54.4(a)(1) and stated that all passive functions of the DGBHVACS are equivalent to the CRHVACS's passive intended functions:

- To provide HVAC to the control room, cable spreading rooms, and battery rooms to ensure habitability during design-basis events, limit reactor protective system/ engineered safety features actuation system temperatures, and minimize hydrogen accumulation;
- To provide seismic integrity and/or protection of safety-related components;
- To maintain the pressure boundary of the system (liquid and/or gas); and
- To maintain electrical continuity and/or provide protection of the electrical system.

The applicant also determined that the following were intended functions of the CRHVACS based on the requirements of 10 CFR 54.4(a)(3):

- Provide technical support center supply and exhaust ventilation duct isolation to confine or retard a fire in the TSC from spreading to adjacent areas; and

- Detect smoke, maintain ventilation in unaffected zones, and remove smoke/supply fresh air to affected zones in the event of a fire in the control room or cable spreading rooms.

On the basis of the intended functions stated above, the portions of the CRHVACS that are identified by the applicant as within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument) and their supports. The applicant identified a total of 45 device types as within the scope of license renewal. Of these 45 device types, the applicant identified 10 that are subject to an AMR. The 10 device types are analyzer element, gravity damper, damper, heat exchanger, HVAC duct, hand valve, fan, temperature transmitter, filter, and radiation element. The applicant also indicated that maintenance of the CRHVACS's pressure boundary is the only passive intended function associated with the CRHVACS that is not addressed in one of the commodity evaluations of the LRA. Therefore, only the pressure-retaining function for the 10 device types subject to an AMR was considered.

The applicant also indicated that some components that are common to many systems have been included in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;
- Electrical control and power cabling, which is evaluated in Section 6.1 of Appendix A to the LRA; and
- Process and instrument tubing and tubing supports, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.24.2 Staff Evaluation

The staff reviewed Section 5.11C of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the CRHVACS components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4, and those subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the CRHVACS (NRC letter dated September 4, 1998), and by letter dated November 16, 1998, the applicant responded to the RAI's.

2.2.3.24.2.1 Control Room and Diesel Generator Buildings' HVAC System Within the Scope of License Renewal

The staff reviewed portions of the UFSAR, including Section 9.8, "Plant Ventilation Systems," to determine if there were any portions of the system that the applicant did not identify as within the scope of license renewal that should have been so identified. The staff also reviewed Section 9.8 of the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA and to determine if there were any structures and components having intended functions that might have been omitted from consideration within the scope of license renewal. The staff also compared the safety-related functions described in the UFSAR to those identified in the LRA.

To help ensure that those portions of the CRHVACS identified as not within the scope of license renewal did not perform any intended functions and, therefore, would not be subject to an AMR, the staff requested additional information from the applicant on the basis of information in the UFSAR and the LRA. In NRC Question No. 5.11.1, the staff noted that Sections 5.11C.1.1 and 5.11C.1.4 in system level scoping provide a summary description of the system boundaries and components within the scope of license renewal for both the CRHVACS and DGBHVACS. The drawings showing the system scoping boundaries were not included. The corresponding drawings for these systems in the UFSAR for CCNPP do not have sufficient details for the staff to clearly understand the system renewal scope. By a letter dated November 16, 1998, the applicant sent Figures 5.11C-1, -2, and -3 depicting the scoping boundaries for the CRHVACS and DGBHVACS. On the basis of the applicant's response, the staff agrees that these figures identify the system level scoping boundaries, and that those LRA boundaries correctly separate system components within these boundaries from those that are outside.

As described above, the staff has reviewed the information submitted in Section 5.11C of Appendix A to the LRA and the applicant's response to the staff's RAI. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the CRHVACS and DGBHVACS and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.24.2.2 Control Room and Diesel Generator Buildings' HVAC System Subject to an Aging Management Review

A. Control Room Heating, Ventilation, and Air Conditioning Systems

The applicant identified a total of 45 device types of the control room HVAC system as within the scope of license renewal. Of these 45 device types, 17 have only active functions and do not require an AMR, 4 device types are evaluated in other sections of Appendix A to the LRA, and 14 device types do not require a detailed evaluation of specific aging mechanisms because they are considered part of a complex assembly whose only passive function is closely linked to active performance. All components of the following 10 device types are subject to an AMR: analyzer element, damper, HVAC duct, fan, filter, gravity damper, heat exchanger, hand valve, radiation element, and temperature transmitter.

Of the device types (including the three electrical/instrumentation device types evaluated in other sections of Appendix A to the LRA) within the scope of the license renewal rule, 32 device types are identified as electrical/instrumentation components. The staff reviewed these 32 device types to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 32 components, the applicant classified the following 17 as having only active functions and, therefore, not requiring an AMR:

- control valve
- converter/relay
- 480-V motor (feed from MCC)
- pressure converter (relay)
- miscellaneous indicating lamp
- pressure control valve
- hand switch
- motor operator
- power lamp indicator
- 480-V motor
- temperature controller
- position-indicating lamp
- fuse
- 125/250-V dc motor
- position switch
- relay
- coil

Seven device types (flow gauge, level gauge, pressure indicator, pressure switch, temperature switch, solenoid valve, and temperature control valve) are associated with the refrigeration units. The refrigeration units perform their intended function (that is, refrigeration) with moving parts. These seven device types are piece parts of the refrigeration units and are, therefore, not subject to an AMR.

Five components (electrical control/power cabling, instrument tubing, flow switch, disconnect switch/link, and pressure differential indicator) are evaluated in Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrument Line," of this SER.

Four electrical/instrumentation components (analyzer element, fan, radiation element, and temperature transmitter) evaluated in this section were classified as subject to an AMR (pressure-retaining function only).

B. Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning System

The applicant stated that the two new diesel generators began operation at CCNPP in 1995. These diesel generators are located in two separate buildings that are dedicated for housing them. The diesel generator buildings' HVAC system provides ventilation, heating, and cooling for these building spaces. Because of the unique circumstances pertaining to these HVAC systems (i.e., they were placed into service approximately 20 years after other similar HVAC systems at CCNPP, and they have a design life of 45 years), an AMR process separate and unique from that used for other plant systems and structures was used. Since aging of the existing control room HVAC system equipment is some 20 years ahead of the aging of the diesel generator buildings' HVAC system equipment, and since this equipment is just at the beginning of its design life, aging management of the new equipment can be deferred and then can be based on the future results of aging management from similar equipment groups associated with the control room HVAC system.

Moreover, the applicant explained that all passive intended functions of the diesel generator buildings' HVAC system are equivalent to the control room HVAC system's passive intended functions. Common attributes, like intended functions, component configuration, material, and service conditions, lead to the conclusion that the effects of aging for these components will be very similar between systems. The aging management programs for the control room HVAC system will provide 20 years of experience for application to the diesel generator buildings' HVAC system. Therefore, there are no new programs or modifications to existing programs needed to manage the aging of the diesel generator buildings' HVAC system.

Regarding the diesel generator buildings' HVAC system, in Section 5.11C.1.4 of Appendix A to the LRA, the applicant explained that the newly installed diesel generator building's HVAC system is similar to the HVAC system in the control room, and it was subject to an AMR process separate and unique from that used for other plant systems and structures. The applicant also stated that the aging management of the new equipment can be deferred, and be based on future results of aging management from similar equipment groups associated with the control room's HVAC system. The applicant demonstrated that the environmental conditions (temperature, moisture content in the air, etc.) and hardware configurations of the diesel generator building's HVAC system are similar to environmental conditions and hardware configuration in the control room in Section 3.6.2.1.4 of this SER.

The staff has reviewed the information in Section 5.11C of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the control room HVAC system structures and components subject to an AMR in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.25 Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems

In Section 5.12, "Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems," of Appendix A to the LRA, the applicant described the identified systems, their intended functions, and the associated structures and components of each system that are within the scope of license renewal, and identified which of those structures and components are subject to an AMR. As described in the LRA, the applicant's main steam (MS) System AMR report includes the extraction steam and nitrogen and hydrogen systems in its scope. The steam generator blowdown system (SGBS) is considered part of the MS system and the portions of the SGBS that are inside the containment are included in the scope of this section of the LRA as part of the main steam system. In Section 5.12 of Appendix A to the LRA, the applicant stated that the portion of the extraction steam system that is within the scope of license renewal is no longer used. The piping was used for reactor vessel head washdown and no longer was exposed to an extraction steam environment. The piping is included in this section of the LRA because it penetrated containment.

2.2.3.25.1 Summary of Technical Information in the Application

As described in the LRA, the MS system (including SGBS piping and isolation valves, as applicable) serves as the flow path for SG output steam to the main high-pressure turbines, the moisture separator reheaters, main feedwater pump turbines, the AFW pump turbines, and the steam seal regulator. The system also provides overpressure protection for the SGs and automatic removal of nuclear steam supply system (NSSS) stored energy and sensible heat following a turbine and reactor trip. The MS system provides the necessary operator control of SG pressure and reactor coolant system (RCS) temperature during plant cooldown and heatup, and a means of heat removal during hot standby and plant cooldown. In addition, the MS system removes excessive moisture from the high-pressure turbine exhaust before it enters the low-pressure turbines via the reheat subsystem.

The applicant stated that during normal plant operations, steam is generated in the SGs and flows through an MS header from each SG to the main turbine high-pressure stop valves. Located in each MS header, at the exit of each SG inside the containment, is a flow restrictor. The main steam isolation valve (MSIV) in each header, outside the containment, represents the downstream terminus of the safety-related MS piping (and the portion of the system within the scope of license renewal). The two MS headers are cross-connected downstream of the MSIVs. Main steam also flows from each of the MS headers, downstream of the containment penetration and upstream of the MSIVs, through air-operated valves, to the AFW turbines when the AFW system is operated. Downstream of the MSIVs, a branch line serves as a steam flow path from each MS header to the moisture separator reheaters and to the steam seal regulator (from No. 11/21 headers only). Another branch line connects to the main feedwater pump turbines.

One atmospheric dump valve (ADV) and eight MS safety valves (MSSVs) are connected to each MS header between the containment penetration and the MSIV. These valves are normally shut and, when opened, exhaust MS to the atmosphere. Four turbine bypass valves are connected to the branch header (downstream of the MSIVs) that supplies MS to the main feedwater pump turbines. These valves are also normally shut and, when operated, exhaust steam to the main condenser.

As described by the applicant in Section 5.12 of Appendix A to the LRA, the function of the extraction steam system is to increase the temperature of the feedwater before it enters the SG, which results in an increase in overall plant efficiency, to minimize thermal shock to the SGs, and to assist in removing moisture from the high-pressure turbine third stage by supplying steam to the first stage of the moisture separator reheater. Wet steam is directed from the three highest stage pressure feedwater heaters in the condensate and feedwater systems en route to the heater drain tanks. Wet steam from the lowest stage pressure feedwater heaters is cascaded to the previous stage feedwater heater and eventually recovered in the condenser.

The function of the nitrogen and hydrogen systems as described by the applicant is to store and distribute the required amounts of nitrogen for normal plant operations, to provide nitrogen for backup to the instrument air system (however, the applicant said that this is currently not in service), and to supply hydrogen to the main generators, the volume control tanks, and the radiological chemistry explosive gas storage room.

The nitrogen and hydrogen system consists of two independent subsystems supplying gases for normal plant operation. The nitrogen subsystem can be further divided into two subsystems, the storage system and the distribution system. The storage system contains an insulated storage tank that is kept pressurized by a combination of ambient and electric vaporizers. The hydrogen system is a common subsystem consisting of hydrogen gas bottles, a truck fill connection, pressure control unit, distribution header, and the associated piping, valves, and controls. The hydrogen subsystem interfaces with one main generator and the chemical and volume control system; however, none of the interfaces are within the scope of license renewal.

The applicant stated that only the nitrogen portion of the nitrogen and hydrogen system is within the scope of license renewal and, therefore, the system is referred to as the nitrogen system in the LRA scoping evaluation. During its review, the staff did verify that the hydrogen portion of the system does not perform any intended functions for license renewal. Since the hydrogen portion of the system does not perform any intended functions, the staff agrees with the applicant's approach and the staff's evaluation only covers the nitrogen system.

Structures and components of the MS system (including piping and isolation valves of the SGBS), extraction steam system, and nitrogen system are within the scope of license renewal based on 10 CFR 54.4(a). The applicant identified the following intended functions of the MS system (and SGBS, as applicable) based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Maintain the pressure boundary of the system (liquid or gas or both).
- Provide closure of the SGBS isolation valves on receipt of a containment spray actuation signal to reduce the heat load on the service water system.
- Provide SG overpressure protection/decay heat removal.
- Provide SG MS line isolation.

- Provide motive steam to AFW pump turbines on receipt of an auxiliary feedwater actuation signal.
- Maintain electrical continuity or protect the electrical system or both.
- Maintain mechanical operability or protect the mechanical system or both.
- Restrict flow to a specified value in support of a DBE response.

In Appendix A to the LRA, the applicant also identified the following intended functions of the MS system based on the requirements of 10 CFR 54.4(a)(3):

- For environmental qualification—Maintain the functionality of electrical components as addressed by the EQ program.
- For fire protection—Provide RCS heat removal in the event of a fire (addressed in Section 5.10, "Fire Protection," of Appendix A to the LRA).
- For SBO—Provide SG overpressure protection/decay heat removal.
- For SBO—Provide SG steam line isolation.
- For SBO—Provide motive steam to AFW pump turbines on receipt of an AFW actuation signal.
- For SBO—Provide valve position indication and manual closure of MSIV bypass isolation valves following a loss of AC power.

The applicant also identified the following intended functions of the extraction steam system based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- To provide containment isolation
- To maintain electrical continuity or protect the electrical system or both

For the nitrogen system, the applicant identified the following intended functions based on the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- To provide containment isolation
- To maintain the pressure boundary of the system

The applicant did not identify any intended functions for the extraction steam or nitrogen systems based on 10 CFR 54.4(a)(3).

The extraction steam piping within the scope of license renewal is the containment penetration piping for reactor head washdown. The portions of the nitrogen system within the scope of license renewal is the containment penetration piping and the piping to the SGs via the surface blowdown piping.

On the basis of the MS system intended functions listed above, the applicant identified that the portions of the MS system that are within the scope of license renewal, and addressed in Section 5.12 of Appendix A to the LRA, include all piping, components supports, instrumentation, and cables for the sections of the MS system from the SG outlet to the MSIVs, AFW branch header to AFW stop control valves, surface and bottom blowdown to containment isolation control valves, the safety-related MS system drains up to the flow restrictors of the motor-operated valves, and the air supply piping to the AFW stop control valves.

The applicant identified 34 device types in the MS system that were designated as within the scope of license renewal because they have at least one intended function. Five of those device types are common to many other plant systems and have been included in the instrument line commodity evaluation in Section 6.4, "Instrument Lines," of Appendix A to the LRA. These five device types are flow transmitters, level switches, pressure indicators, pressure switches, and pressure transmitters. One additional device type, hand valves, has also been evaluated in Section 6.4 of Appendix A to the LRA for those hand valves that have a specific function associated with an instrument.

The portions of the extraction steam system within the scope of license renewal consist of piping, component supports, and hand valves associated with the extraction steam containment penetrations and two Class 1E fuses and their associated cables, panels, and supports. Three device types (Class GB piping, fuses, and hand valves) were determined by the applicant to be within the scope of license renewal because they have at least one intended function. The applicant indicated that there were no extraction steam system device types that are included in separate commodity evaluations.

The portions of the nitrogen system within the scope of license renewal consist of piping, component supports, and check and hand valves associated with the SG blowdown and containment penetrations 20A, 20B, and 20C. The applicant identified the following four device types in the nitrogen system that are designated as within the scope of license renewal: Class HB piping, Class EB piping, check valve types, and hand valve types.

For all the systems in Section 3.12 of Appendix A to the LRA, the applicable component supports, cables, and electrical components are addressed in the commodity evaluation sections for those commodities (i.e., Sections 3.1, 6.1, and 6.2).

Of the 34 device types in the main steam system, which the applicant identified as within the scope of license renewal, the applicant identified the following 18 device types as subject to an AMR: Class HB piping, Class EB piping, accumulator, eight valve types (check, control, flow control, hand, motor-operated, relief, pressure control, and solenoid valves), encapsulation, flow elements, flow orifices, heat exchangers, current/pneumatic devices, temperature elements, and tanks.

Of the three device types identified for the extraction steam system that are within the scope of license renewal, the applicant determined that fuses perform its intended function(s) with moving parts or with a change in configuration or properties. Therefore, the two remaining device types (Class GB piping and hand valves) are included in the AMR of Section 5.12 of Appendix A to the LRA. Additionally, all four of the device types in the nitrogen system that are within the scope of license renewal are included in this AMR.

In addition, the applicant identified device types from three other systems that were included in the applicant's main steam system AMR report. These are the encapsulations for the feedwater system and chemical and volume control system per the auxiliary building AMR report, and hand valves from the chemical addition system.

2.2.3.25.2 Staff Evaluation

The staff reviewed Section 5.12 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the main steam, steam generator blowdown, extraction steam, and nitrogen and hydrogen system components within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding these systems (NRC letters to BGE dated August 31 and September 24, 1998), and by letter dated November 16, 1998, the applicant responded to those RAIs.

2.2.3.25.2.1 Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems Within the Scope of License Renewal

During the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the MS system, SGBS extraction steam system, and the nitrogen and hydrogen systems to determine if there were any components that the applicant did not identify as within the scope of license renewal but that were necessary to perform one of the identified intended functions of these systems. The staff also reviewed the design basis for the systems as described in the UFSAR to determine if there were any additional system functions that were intended functions and, therefore, might require certain components that the applicant did not identify to be within the scope of license renewal.

The staff's review of the UFSAR and flow diagrams did not reveal any additional structures or components of the MS system, SGBS system, extraction steam system, and nitrogen and hydrogen systems that should be within the scope of license renewal. The staff's review involved sampling various components and interface points that were identified as not being within the scope of the rule. No component or structure omissions were identified. The applicant stated that only the nitrogen portion of the nitrogen and hydrogen system is within the scope of license renewal and, therefore, the system is referred to as the nitrogen system in the LRA scoping evaluation. Since the hydrogen portion of the system does not perform any intended functions, the staff agreed with the applicant's approach and evaluated only the nitrogen system. As a result of the initial review, the staff did request additional information to help ensure there were no omissions from the applicant's list of components within the scope of license renewal. One of these RAIs, NRC Question No. 5.12.6, asked the applicant to clarify if the scope included the MSIVs and if the scope extends to the first restraint downstream of each MSIV. In its response, the applicant verified that the piping between the MSIVs and the next downstream anchor is within the scope of license renewal. The applicant further indicated that this piping is addressed in Section 3.1A, "Piping Segments That Provide Structural Support," of Appendix A to the LRA. The staff's evaluation of Section 3.1A is contained in Section 2.2.3.2 of this SER.

During its review, the staff also requested additional information regarding extraction steam piping inside the containment that was abandoned in place. In NRC Question No. 5.12.7, the staff asked the applicant to identify if this piping was seismically supported and whether it was in the seismic Category II/I equipment program. Additionally, the staff asked the applicant to address similar abandoned piping in other systems. The applicant stated that all abandoned equipment was reviewed and most was determined not to be located in the proximity of seismic Category I equipment and if some is, it is considered as seismic Category II/I equipment and has been determined to be seismically adequate. The applicant noted that all items in the plant are observed during the course of system and structure walkdowns and during system maintenance. During these activities, degradation that may exist is documented, evaluated, and resolved in accordance with the applicant's corrective action program. For these reasons, the applicant has determined that abandoned piping and equipment are not within the scope of license renewal. Because this abandoned equipment does not have a fluid operating environment and the maintenance of the pressure boundary is not required, plus the fact that equipment supports are addressed in Section 3.1, "Component Supports," of Appendix A to the LRA, the staff concurs with the applicant that this piping does not have to be within the scope of license renewal. As a result of its review, the staff also did not identify any additional intended functions that could result in additional components (components not identified by the applicant) being within the scope of license renewal.

As described above, the staff has reviewed the information presented in Section 5.12 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures and components (device types) of the MS system, SGBS, extraction steam system, and nitrogen and hydrogen systems within the scope of license renewal in accordance with the requirements in 10 CFR 54.4.

2.2.3.25.2.2 Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems Subject to an Aging Management Review

The staff focused its evaluation of this section on whether the applicant has properly identified the structures and components subject to an AMR from among the systems, structures, and components that have been identified within the scope of license renewal. The staff reviewed selected structures and components identified by the applicant within the scope of license renewal to verify that they have been identified as subject to an AMR if they perform an intended function without moving parts or without a change in configuration and properties and are not subject to replacement based on a qualified life or specified time period. The staff compared the information in the UFSAR with the information in the application to select the structures and components.

The applicant divided the structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Tables 5.12-1, 5.12-2, and 5.12-3 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct and found no omissions in classification. Therefore, the staff finds reasonable assurance that the applicant has identified the structures and components subject to an AMR for the main steam, steam generator blowdown, extraction steam, and nitrogen and hydrogen systems.

Of 38 device types within the scope of the license renewal rule, 24 are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 24 components, the applicant classified the following 11 as having only active functions and, therefore, not requiring an AMR.

- fuse
- hand switch
- pressure-indicator controls
- position switch indicating lamp
- hand controller
- current/current device
- relay
- miscellaneous indicating lamp
- hand-indicator controller
- power lamp indicator
- position switch

The following seven device types are evaluated in Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrumentation Lines," of this SER.

- flow transmitter
- pressure switch
- panel
- level switch
- pressure transmitter
- pressure indicator
- control power cabling

Structures and Components Subject to an Aging Management Review

The following six electrical/instrumentation components evaluated in this section were classified as subject to an AMR (only pressure boundary/body).

- control valve
- MOV
- flow element
- solenoid valve
- current/pneumatic device
- temperature element

The staff agrees with the applicant's determination of the components subject to an AMR and that the 11 components excluded from an AMR perform their functions with moving parts or by changing configuration or properties, which is consistent with 10 CFR 54.21(a)(1).

Fourteen device types within the scope of license renewal are mechanical components or structural supports. The structural supports for piping, cables, and components are evaluated in Section 2.2.3.1, "Component Supports," of this SER.

The remaining 13 device types are piping and mechanical components that perform passive functions. These device types are listed in Tables 5.12-1, 5.12-2, and 5.12-3 of Appendix A to the LRA. Some device types appear more than once in these tables. The staff finds that the applicant included all of these device types as subject to an AMR, which is acceptable.

The staff has reviewed the information presented in Section 5.12 of Appendix A to the LRA. On the basis of its review of selected structures and components, the staff finds reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the main steam, steam generator blowdown, extraction steam, and nitrogen and hydrogen systems in accordance with the requirements in 10 CFR 54.21(a)(1).

2.2.3.26 Nuclear Steam Supply System Sampling System

In Section 5.13, "Nuclear Steam Supply System Sampling System," of Appendix A to the LRA, the applicant described the structures and components of the NSSS sampling system at the plant site that are within the scope of license renewal, and identified which of these are subject to an AMR.

2.2.3.26.1 Summary of Technical Information in the Application

The NSSS sampling system is designed to permit the sampling of liquids, steam, and gases for radioactive and chemical control of plant primary fluids. The NSSS sampling system is comprised of five subsystems: reactor coolant sampling, steam generator blowdown sampling, radioactive miscellaneous waste sampling, gas analyzing sampling, and post-accident sampling.

- Reactor Coolant Sampling

  The reactor coolant sampling subsystem samples liquids and gases for analysis and control of chemical and radiochemical concentrations. The reactor coolant sampling subsystem consists of a SS sink enclosed inside a hood. The hood is ventilated by an individual blower through a high-efficiency filter. The hood contains piping, valves, coolers, instrumentation, and sample vessels necessary to take liquid and gaseous samples from various systems.

- Steam Generator Blowdown Sampling

  The steam generator blowdown sampling subsystem provides a means for sampling liquids from the steam generators to detect conditions that cause carryover, corrosion, and fouling of heat transfer surfaces, and to aid in detection of a possible reactor coolant-to-steam generator leak. This subsystem also provides a means for sampling reactor coolant makeup water. The steam generator blowdown sampling subsystem consists of one conditioning rack-panel unit and one ventilating hood installed for each unit; these are located inside the same sampling room as the reactor coolant sample hoods. The conditioning rack section of the steam generator blowdown subsystem contains isolation valves, primary coolers, rod-in-tube devices, an isothermal bath, and a chiller.

- Radioactive Miscellaneous Waste Sampling

  The radioactive miscellaneous waste sampling subsystem provides a means for sampling liquids from various radioactive waste processing systems to determine the chemical and radiochemical content preceding discharge, and to aid in evaluating the performance of waste system components. The radioactive miscellaneous waste sampling subsystem is located inside the ventilating hood for the Unit 1 steam generator blowdown sampling subsystem, and is used to obtain samples from which the chemical and radiochemical content of miscellaneous waste is determined. This subsystem is common to both units.

- Gas Analyzing Sampling

  The gas analyzing sampling subsystem provides a means for sampling gases to determine (1) the hydrogen concentration of the containment atmosphere and the reactor coolant waste tanks and (2) the oxygen concentration in the pressurizer quench tanks and various miscellaneous waste systems. This subsystem also provides a means for obtaining grab samples of gases in the containment atmosphere in the post-accident environment. This subsystem consists of two hydrogen analyzer cabinets, two hydrogen sample select cabinets with separate manifolds for isolation valves and sample selection solenoid valves, and one oxygen analyzer cabinet with a manifold for isolation valves.

The two analyzer cabinets used for hydrogen measurement each include a sample pump, cooler, tubing, valves, and analyzer element. The analyzer cabinet used for oxygen grab sample measurement includes a sample pump, cooler, piping, valves, and a sample syringe port.

- Post-Accident Sampling

  The original post-accident sampling system (PASS) is no longer in service because of high maintenance and the unreliability of the system. The applicant modified the reactor coolant sampling and gas analyzing subsystem to provide a post-accident capability that relies, with one exception, on grab sample analyses to meet regulatory requirements for both the RCS and the containment atmosphere.

The LRA described the intended functions of the components in the NSSS sampling system and identified the systems, structures, and components considered within Section 5.13 of Appendix A to the LRA that are within the scope of license renewal, as defined in 10 CFR 54.4(a). These SSCs include accumulators, air dryers, piping, valves and valve operators, panels, instruments, sample vessels, heat exchangers, pumps, and associated electrical devices. Among these structures and components, the applicant identified the following device types as subject to an AMR: piping, accumulator, analyzer element, check valve, control valve, control valve operator, air dryer, flow indicator, flow indicator controller, flow orifice, hand valve, heat exchanger, pressure control valve, pressure indicator, pressure switch, pump/driver assembly, and solenoid valve. The applicant also identified electrical panels, electrical components, and cables as subject to an AMR.

2.2.3.26.2 Staff Evaluation

The staff reviewed Section 5.13 of Appendix A to the LRA, as well as additional information from the UFSAR and the piping and instrumentation drawings (P&IDs), to determine whether there is reasonable assurance that the applicant has identified and listed those structures and components for the NSSS sampling system that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements in 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2.3.26.2.1 NSSS Sampling System Within the Scope of License Renewal

In the first step of its evaluation, the staff determined whether the applicant has properly identified the systems, structures, and components within the scope of license renewal. In Section 5.13.1.2 of Appendix A to the LRA, the applicant has identified the portion of the NSSS sampling system that is within the scope of license renewal, which includes all safety-related components (electrical, mechanical, and instrument) and their supports. The staff has reviewed the information in Section 5.13 of Appendix A of the LRA. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the structures or components within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.26.2.2 NSSS Sampling System Subject to an Aging Management Review

The applicant has described the safety-related portion of the following subsystems that perform their intended function without moving parts or without changes in configuration or properties and categorized those structures and components into device types subject to an AMR (listed in Table 5.13-1 of Appendix A to the LRA).

- RCS sample header isolation control valves (CVs), including all intervening piping and the connected test/vent/drain root valves;
- Containment isolation solenoid-operated valves (SOVs) in the sample return lines from the reactor coolant sample hoods to the reactor coolant drain tank and the piping between these valves, including RCS tubing inside the containment;
- Piping in the RCS sample headers between the RCS and the CVs, the test valves connected to this piping, and the isolation valves in the flow path;
- Sample cooler in each of the reactor coolant sample hoods, including the shell and tubes; the hand valves in the sample lines from the charging pump discharge and the low pressure safety-injection pump discharge;
- Steam generator (SG) blowdown sampling subsystem components from both the sample points in the SG blowdown piping through the tubes in the sample cooler, up to and including the rod-in-tube pressure-reducing hand valves downstream of the sample coolers in the conditioning racks;
- Radioactive miscellaneous waste sampling subsystem hand valves in the spent fuel pool filter and demineralizer sampling lines including the sample coolers; and
- All gas-analyzing sampling subsystem piping and components associated with sampling analysis of gases for hydrogen concentration, including the lines provided for sampling of oxygen concentration for each unit's pressurizer quench tank, the containment isolation SOVs, and the piping between these valves and the quench tanks.

The applicant has divided those structures and components of the NSSS sampling system into two groups of device types: one group of device type that is not subject to an AMR and the other that is subject to an AMR. The staff reviewed 100 percent of the information submitted in the application to verify that the applicant's grouping is correct.

Of the 36 device types within the scope of the license renewal rule, 24 device types are electrical/instrumentation components and the remaining 12 are mechanical components. The staff reviewed all device types in the scope of license renewal to verify that the applicant did not omit any device type that should be subject to an AMR. Of the 24 components, the applicant classified the following 14 as having only active functions and, therefore, not requiring an AMR:

- analyzer alarm
- analyzer indicator
- analyzer recorder
- analyzer converter (relay)
- circuit breaker
- voltage/current device
- fuse
- hand switch
- power lamp indicator
- relay
- temperature controller
- heater
- position indicating lamp
- position switch

Two device types, panel and control/power cabling, are evaluated in Section 2.2.3.32, "Cables"; and Section 2.2.3.33, "Electrical Commodities," of this SER. The following eight electrical/ instrumentation components are evaluated in this section; they were classified as subject to an AMR (only pressure boundary/body):

- analyzer element
- control valve
- control valve operator
- flow indicator
- flow-indicator controller
- pressure indicator
- pressure switch
- solenoid valve

The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

As described above, the staff finds no omissions by the applicant; therefore, there is reasonable assurance that the applicant has identified the structures and components subject to an AMR for the NSSS sampling system.

The staff reviewed the information in Section 5.13 of Appendix A to the LRA and has determined that there is reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the NSSS sampling system to meet the requirements in 10 CFR 54.21(a)(1).

2.2.3.27 Radiation Monitoring System

In Section 5.14, "Radiation Monitoring System" (RMS), of Appendix A to the LRA, the applicant described portions of the RMS and their components that are within the scope for license renewal, and identified which of those components are subject to an AMR.

2.2.3.27.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the RMS is designed to warn operating personnel about an increasing radiation level or abnormal radioactivity concentrations at selected points in the plant. This warning system may also indicate a system or component malfunction that needs operator action, or it may perform automatic protective actions to correct and/or isolate an abnormal condition to prevent an uncontrolled release of radioactive material to the environment. The RMS also monitors the releases of radioactive effluents from the plant so that the releases do not exceed allowable limits in accordance with 10 CFR Part 50, and are maintained ALARA in accordance with Appendix I to 10 CFR Part 50.

The RMS is divided into two subsystems: the area RMS and the process RMS. The area RMS includes area radiation monitors located throughout the plant, four containment area radiation monitors, and two containment high range gamma radiation monitors. The process RMS includes the plant's main vent radiation monitors, wide-range effluent gas radiation monitors, containment atmosphere radiation monitors, waste gas discharge radiation monitor, liquid waste processing discharge radiation monitor, condenser air removal discharge radiation monitor, component cooling system (CCS) radiation monitor, service water (SRW) system radiation monitor, steam generator blowdown tank discharge radiation monitor, steam generator blowdown recovery radiation monitor, atmosphere radiation monitors (includes the control room ventilation radiation monitor as well as other ventilation radiation monitors), and main steam effluent radiation monitors.

The RMS comprises the following types of equipment: piping/tubing (provides system flowpath and maintains pressure boundary), pumps (provide motive force to move fluids being sampled), valves (provide containment isolation and system alignment/isolation), filters (filter air to protect downstream components), and instrumentation/elements (provide information to operators and signals to control equipment).

The RMS is within the scope of license renewal based on 10 CFR 54.4(a). The following RMS intended functions were determined on the basis of the requirements of 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide containment area radiation signal to engineered safety features actuation system for containment isolation and radiological release control.

- Provide containment high-range radiation signal for containment environment monitoring and for isolating the containment vent/hydrogen purge lines.

- Maintain the pressure boundary of the system.

- Provide containment isolation of the containment atmosphere and purge air monitor sampling line.

- Monitor and record wide-range gaseous activity/release rate through the main plant vent and provide indications/alarms in the control room.
- Monitor and record radiation levels indicative of effluent activity in the main steamlines and provide indications/alarms in the control room.
- Provide testing capability and prevent spurious actuation of control room radiation monitoring circuitry.
- Maintain electrical continuity and/or provide protection of the electrical system.
- Provide seismic integrity and/or protection of safety-related components.

The applicant determined that the following were intended functions of the RMS based on the requirements of 10 CFR 54.4(a)(3):

- Provide information to assess the environs and plant condition during and following an accident.
- Maintain functionality of electrical equipment as addressed by the environmental qualification program.

On the basis of the intended functions listed above, the portions of the RMS that are identified by the applicant as within the scope of license renewal include the following equipment types: piping, components, component supports, instrumentation, panels, and cables associated with the following radiation monitors: containment area radiation monitors, containment high-range gamma radiation monitors, wide-range effluent gas radiation monitors, containment atmosphere radiation monitors, CCS radiation monitor, SRW system radiation monitor, control room ventilation radiation monitor, and main steam effluent radiation monitors. The shaded areas of Figures 5.14-1 through 5.14-8 of Appendix A to the LRA indicate the portions of the system within the scope of license renewal. The applicant identified a total of 33 device types within the scope of license renewal for this system. Of these 33 device types, the applicant identified 16 device types that were subject to an AMR. Of those 16 types, 5 were not evaluated as part of the RMS AMR, either because they are subject to a replacement program, they are evaluated in an AMR for another system, or they are evaluated in a commodity evaluation. The remaining 11 device types requiring an AMR specifically within the scope of the RMS are piping, check valve, control valve, hand valve, motor-operated valve, flow element, flow indicator, radiation element, filter, radiation test point, and solenoid valve. The applicant determined that for these 11 device types, retaining the pressure boundary and providing containment isolation are the only passive intended functions that are within the scope of the AMR for the RMS.

Both the low-range and mid/high-range pumps of the wide-range effluent gas radiation monitors are subject to maintenance replacement programs. The RMS components requiring an AMR that are evaluated in an AMR for another system are the component cooling system radiation monitor (evaluated in the CCS AMR), service water system radiation monitor (evaluated in the SRW system AMR), and control room ventilation radiation monitor (evaluated in the control HVAC [heating, ventilation, and air conditioning] system AMR).

The applicant also indicated that some components in the RMS that are common to many systems have been included in the commodity AMRs, which address those components for the entire plant. Therefore, they were not included in the individual system sections. These components are the following:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1 of Appendix A to the LRA;
- Electrical cabling, which is evaluated in Section 6.1 of Appendix A to the LRA; and
- Instrument tubing and piping and their associated fittings, instrument valves, and supports, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.27.2 Staff Evaluation

The staff reviewed Section 5.14 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has identified the RMS components and supporting structures that are within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the RMS (NRC letter to BGE dated August 6, 1998), and by letter dated September 25, 1998, the applicant responded to those RAIs.

2.2.3.27.2.1 Radiation Monitoring System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including the piping and instrumentation diagrams (P&IDs) for the RMS, and compared them to the diagrams in Appendix A to the LRA to determine if there were any additional portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. In an RAI, the staff identified the following radiation monitors and requested the bases for eliminating those monitors from the scope of license renewal: plant main vent monitor, waste gas discharge monitor, liquid waste processing discharge monitor, condenser air removal discharge monitor, steam generator blowdown tank discharge monitor, steam generator blowdown recovery monitor, and atmosphere monitor (other than the monitor for control room ventilation). In response to NRC Question No. 5.14.1, the applicant stated that the radiation monitors discussed above are non-safety-related and do not perform any of the system intended functions based on 10 CFR 54.4(a)(1), 54.4(a)(2), 54.4(a)(3), and 54.4(b). Further, the licensee clarified that although the non-safety-related plant main vents radiation monitors are not in the scope of license renewal, the safety-related wide-range effluent gas radiation monitors that monitor the plant main vents are in the scope. Although the non-safety-related containment atmosphere radiation monitors are not within the scope of license renewal, the containment penetrations, including the safety-related containment isolation valves, are within the scope of license renewal. Therefore, the staff finds the elimination of those monitors from the scope of license renewal acceptable because those monitors are non-safety-related and do not perform any of the functions specified in 10 CFR 54.4(a)(1), 54.4(a)(2), 54.4(a)(3) and 54.4(b).

During its review, the staff identified that in Figure 5.14-5, "Component Cooling System Radiation Monitors"; Figure 5.14-6, "Service Water System Radiation Monitors"; and Figure 5.14-7, "Control Room Ventilation Radiation Monitors" in Appendix A to the LRA, a number of radiation monitor instruments were not included in the scope of license renewal. The applicant explained in a telephone conference call on October 7, 1998, that the components functioning as a pressure boundary are within the scope of license renewal, but the components simply being used for the radiation monitoring function are not within the scope of license renewal because they do not perform a safety-related function. The staff finds this acceptable because those monitors are non-safety-related and do not perform any of the function specified in 10 CFR 54.4(a)(1), 54.4(a)(2), 54.4(a)(3), and 54.4(b). The staff also identified several valves in Figure 5.14-7, "Control Room Ventilation Radiation Monitors," and Figure 5.14-8, "Main Steam Effluent Radiation Monitors," as not being included within the scope of license renewal. The licensee explained that those valves are evaluated separately in Section 5.11C, "Control Room and Diesel Generator Building's Heating, Ventilating, and Air Conditioning Systems," and Section 5.12, "Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems," in Appendix A to the LRA.

The staff reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA to verify if there were any structures or components having intended functions that might have been omitted from within the scope of license renewal. As described in detail above, the staff found no omissions by the applicant. On the basis of the applicant's response and the supporting information in the UFSAR, the staff concludes that these portions of the RMS that were not identified as within the scope of license renewal did not perform any intended functions that would have designated these portions of the system to be within the scope of license renewal.

As described above, the staff has reviewed the information presented in Section 5.14 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the RMS and the associated structures and components thereof that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.27.2.2 Radiation Monitoring System Subject to an Aging Management Review

In Section 5.14.1.2 of Appendix A to the LRA, the applicant identified which components from the radiation monitoring system (RMS) are within the scope of license renewal. The RMS is associated with the following radiation monitors: containment area radiation monitors, containment high-range gamma radiation monitors, wide-range effluent gas radiation monitors, containment atmosphere radiation monitors, component cooling system radiation monitor, service water system radiation monitor, control room ventilation radiation monitor, and main steam effluent radiation monitors. The applicant categorized structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.14-1 of Appendix A to the LRA). The staff reviewed the information to verify that the applicant's grouping was correct. As described in detail below, the staff finds reasonable assurance that the applicant has identified the structures and components for the RMS that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Of the device types within the scope of license renewal, 16 were determined to have passive intended functions and, therefore, to require an AMR. Of the 16 device types requiring an AMR, 12 are electrical/instrumentation components. The following five components are evaluated under Section 2.2.3.14, "Component Cooling System"; Section 2.2.3.30, "Service Water System"; Section 2.2.3.24, "Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems"; Section 2.2.3.32, "Cables"; and Section 2.2.3.35, "Instrument Lines," of this SER.

- CCS radiation element
- SWS radiation element
- control room ventilation radiation element
- control/power cabling
- instrumentation tubing/valves

The remaining seven electrical/instrumentation device types evaluated in this section were classified as subject to an AMR (only pressure boundary/body):

- control valve
- MOV
- flow element
- flow indicator
- radiation test point
- radiation element
- solenoid valve

The staff also reviewed the non-electrical components in the radiation monitoring system in order to determine whether the applicant has properly identified the structures and components subject to an AMR. The staff reviewed the information in Table 5.14-1 of Appendix A to the LRA to ascertain that the applicant has identified all components that are subject to an AMR. The following components were identified as subject to an AMR:

- piping
- check valves
- hand valves
- filters

The staff has reviewed the information in Section 5.14.1.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of the staff's review of the information submitted by the applicant, the staff has determined that there is reasonable assurance that the applicant has appropriately identified the structures and components of the RMS that are subject to an AMR as required under 10 CFR 54.21(a)(1).

2.2.3.28 Safety Injection System

In Section 5.15, "Safety Injection System," of Appendix A to the LRA, the applicant described the structures and components of the safety injection (SI) system at the plant site that are within the scope for license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.28.1 Summary of Technical Information in the Application

As described in Appendix A to the LRA, the major functions of the SI system are to (a) supply emergency core cooling in the unlikely event of a loss-of-coolant accident (LOCA); and (b) increase shutdown margin after the rapid cooldown of the reactor coolant system (RCS) caused by a rupture of a main steam line. These functions are performed by injecting borated water into the RCS. The SI system is also utilized to (a) remove heat from the RCS during plant cooldown once RCS temperature is below 300 ° F; (b) maintain suitable RCS temperatures during refueling and maintenance operations; and (c) provide storage capacity for borated water needed for spent fuel pool (SFP) and refueling pool operations. During normal plant operations, the SI system is maintained in a standby mode with components aligned for injection to the RCS.

The SI system consists of high-pressure and low-pressure subsystems that provide borated water to four SI headers, each connected to associated cold leg piping in the RCS. In addition to the associated piping, valves, controls, and instrumentation, the SI system for each CCNPP unit comprises the following major components:

- Three electric motor-driven high-pressure safety injection (HPSI) pumps, each with an associated seal cooler;
- Two electric motor-driven low-pressure safety injection (LPSI) pumps, each with an associated seal heat exchanger (HX);
- Four safety injection tanks (SITs); and

- A refueling water tank (RWT), with an associated electric motor-driven pump and heat exchanger (RWTHX).

The SI system is composed of the following categories of equipment and devices:

- Piping—Convey borated water to perform system functions.
- Valves—Control valves (CVs), check valves (CKVs), hand valves (HVs), motor-operated valves (MOVs), and relief valves (RLVs), which provide containment isolation and system alignment, isolation, and protection.
- Instruments—Measure system flow rates, tank levels, and temperatures.
- Tanks—Store borated water used for injection into the RCS and for refueling purposes.
- HXs—Provide a heat sink for seal cooling water for system pumps, and prevent freezing of borated water in the RWT.
- Pumps—Move borated water into the RCS, into the SITs, and into the RWT.

In Appendix A to the LRA, the applicant identified the following intended functions for the SI system and its components based on the requirements of 10 CFR 54.4(a)(1) and (2):

- To provide borated water to the RCS for reactivity, pressure, and level control in response to design-basis events (DBEs) upon a safety injection actuation signal (SIAS);
- To provide borated water passively to the RCS for reactivity, pressure, and, level control when RCS pressure drops below 200 psig;
- To recirculate lost coolant back to the RCS and the containment spray (CS) system (recirculation mode);
- To send a signal to the engineered safety features actuation system (ESFAS) for a recirculation actuation signal (RAS);
- To provide long-term core flush via hot leg injection;
- To provide containment isolation of the SI system during a loss-of-coolant accident;
- To maintain the pressure boundary of the system (liquid and/or gas);
- To maintain mechanical operability and/or protect the mechanical system;
- To provide borated water from the RWT to the CS pumps;

- To maintain electrical continuity and/or protect the electrical system;
- To provide makeup water from the RWT to the SFP during a fuel handling incident; and
- To restrict flow to a specified value in support of a DBE response.

The following SI system intended functions were determined based on the requirements of 10 CFR 54.4(a)(3):

- For fire protection—To (a) provide RCS pressure and inventory control to ensure safe shutdown in the event of a severe fire, (b) provide RCS heat removal by realigning and operating in the shutdown cooling (SDC) mode, and (c) prevent inadvertent dumping of the SITs when RCS temperature is less than 300 °F;
- For environmental qualification—To (a) provide information used to assess the environs and plant condition during and after an accident, and (b) maintain functionality of electrical components as addressed by the environmental qualification program; and
- For station blackout—To (a) provide valve position indication and closure of containment isolation valves, and (b) provide RCS isolation to maintain RCS inventory.

All components of the SI system that meet the environmental qualification or station blackout criteria of 10 CFR 54.4(a)(3) are also safety-related.

On the basis of the intended functions described in Appendix A to the LRA, the portion of the SI system that is within the scope of license renewal includes all components (electrical, mechanical, and instrumental) and their supports associated with the storing and delivering of borated water to the RCS. The following system flowpaths allow transfer of borated water to the RCS interface at each of the four-loop inlet CKVs:

- Injection mode flowpath (post-DBE operations after a SIAS; motive force provided by HPSI pumps)—from the RWT, through the running HPSI pumps (i.e., two of the three installed pumps), to the SI header CKVs and loop inlet CKVs by way of both (a) a main HPSI header and four main HPSI header MOVs and (b) an auxiliary HPSI header and four auxiliary HPSI header MOVs;
- Injection mode flowpath (post-DBE operations after a SIAS; motive force provided by LPSI pumps)—from the RWT, through both LPSI pumps, into a common discharge header, through the LPSI flow CV, the four LPSI header MOVs, to the SI header CKVs and loop inlet CKVs;
- Injection mode flowpath (post-DBE operations after RCS pressure drops below approximately 200 psig; motive force provided by pressurized SITs)—from each of the

four SITs, through the open SIT outlet CKVs and SIT outlet MOVs, to the loop inlet CKVs;

- Recirculation mode flowpath (post-DBE operations after a RAS; motive force provided by HPSI pumps)—from the interface with the containment emergency sump, through the containment sump discharge MOVs and through the HPSI injection mode flowpath described above; and

- SDC mode flowpath (motive force provided by LPSI pumps)—from the RCS interface at the outlet of the SDC header return isolation MOV inside the containment, through the SDC header return isolation MOV outside the containment and through the LPSI injection mode flowpath described above, with a portion of the borated water passing through the shutdown cooling heat exchanger (SDCHX) LPSI inlet MOV into the CS system. After passing through the SDCHXs and the SDC temperature/flow CV in the CS system, this fluid reenters the SI system on the downstream side of the LPSI flow CV, rejoining the remainder of the borated water in the SDC mode flowpath.

The following system flowpaths are part of the system pressure boundary and are also within the scope of license renewal for the SI system:

- Minimum-flow recirculation flowpaths for pumps (motive force provided by associated pumps)—from the discharge headers for each HPSI and LPSI pump through an associated flow orifice and mini-flow return CKV, and from the CS system interface at the outlet of each CS pump mini-flow return CKV through the mini-flow return to RWT isolation MOVs, through the common RWT recirculation header back into the RWT.

- Circulation flowpath for the RWT—from the RWT, through the RWT circulating pump, the tubes in the RWTHX, and back into the RWT. (The RWTHX bonnets, covers, tubes, and associated SS welds form a part of the SI system pressure boundary. The intended function for other subcomponent parts of the RWTHX (i.e., the shell and associated carbon steel welds, fittings, studs, nuts, and vessel supports) is to provide structural support for the tube assembly. A pressure boundary breach of the plant heating system will not impact this support function.)

- SDC recirculation flowpaths—from the CS system interfaces in the SDC return header (a) through the SDCHX recirculation stop CV to the LPSI pump suction header, or (b) to the common RWT recirculation header, or (c) through the SI-to-CVCS flow instrumentation to the CVCS interface at the outlet of the SDC supply to the CVCS backup HV.

- Leakoff return flowpaths for each SIT—from the SI system piping between the SIT outlet and loop inlet CKVs, through the SIT CKV leakage CV, through common leakoff return piping and a flow orifice to (a) to the liquid waste system interface at the outlet of the leakoff-to-reactor coolant drain tank CV, or (b) through the normally closed SI leakoff return header isolation HVs to the common RWT recirculation header.

Additional components that are part of the system pressure boundary along these flowpaths (e.g., piping, instruments, seal coolers and HXs for pumps, SIT fill-and-drain CVs, normally closed HVs, RLVs, solenoid-operated valves in instrument air supply piping) and their supports are also within the scope of license renewal for the SI system

On the basis of the intended functions stated above, 53 device types were listed from the portions of the SI system that are identified by the applicant as within the scope of license renewal. Of these 53 device types, the applicant identified 16 that are subject to an AMR. The 16 device types are Class CC piping (-CC), Class DC piping (-DC), Class GC piping (-GC), Class HC piping (-HC), check valve (CKV), control valve (CV), flow element (FE), flow orifice (FO), hand valve (HV), heat exchanger (HX), motor-operated valve (MOV), pump/driver assembly (PUMP), relief valve (RLV), temperature element (TE), temperature indicator (TI), tank (TK).
The applicant also indicated that some components in the SI system that are common to many systems have been included in the separate commodity reports addressing those components for the entire plant in Appendix A of the LRA. Therefore, they were not included in the individual system sections. These components are:

- Except for the RWTHX supports that are addressed in this section of the SER, 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 Appendix A to the LRA. The RWTHX supports are evaluated as subcomponents of the HX device type.

- Electrical control and power cabling is evaluated for the effects of aging in the Electrical Cables Commodity Evaluation in Section 6.1 of Appendix A to the LRA. This commodity evaluation completely addresses the passive intended function of maintaining electrical continuity and/or protecting the electrical system for the SI system.

- Instrument tubing and piping and the associated tubing 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 Appendix A to the LRA. This commodity evaluation partially addresses the passive intended function of maintaining the pressure boundary of the system (liquid and/or gas) for the SI system.

2.2.3.28.2 Staff Evaluation

The staff reviewed Section 5.15 of Appendix A to the LRA to determine whether the applicant has identified with reasonable assurance that the SI system components and supporting structures are within the scope of license renewal per 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished in two steps, as described in the following two subsections.

2.2.3.28.2.1 Systems, Structures, and Components Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR for the SI system, and compared the information in the UFSAR with the information in Appendix A to the LRA to determine if there were any portions of the system piping and other components that the applicant should have identified as within the scope of license renewal. The staff then reviewed structures and components outside the portion identified by the applicant and, as described below, requested that the applicant provide additional information and/or clarifications for selected structures and components to verify that they do not have any of the intended functions listed in 10 CFR 54.4(a). The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structure or component having an intended function was omitted from consideration within the scope of license renewal.

After completing the initial review, by letter dated September 2, 1998, the staff issued RAIs regarding the SI system. By letter dated November 9, 1998, the applicant's responded to those RAIs. NRC Question No. 5.15.1 asked the applicant to clarify why solenoid valves were listed on page 5.15-12 of Appendix A to the LRA as having only active functions. 10 CFR 54.21(a)(1) states that valve bodies are passive

In response, the applicant stated that the SI system, as shown in the drawings on pages 5.15-6 and 5.15-7 of Appendix A to the LRA, do not include any solenoid valve bodies within the evaluation boundary. The key provided with the drawings shows the components are flow orifices, control valves, hand valves, check valves, motor-operated valves, relief valves, and spool pieces. Solenoid valves are used in the non-safety related air supply to control valves in the SI system. Therefore, solenoid valves do not provide the pressure boundary function in the SI system and, therefore, are not within scope. Page 5.15-12 of Appendix A to the LRA is, therefore, correct in identifying solenoid valves as one of the 29 device types having only active functions.

The staff reviewed the applicant's response and the function of the solenoid valves. Although the staff did not agree with the applicant's basis for omitting the solenoid valves from an AMR, the staff determined from a review of the UFSAR that the control air solenoid valves do not perform an intended function under 10 CFR 54.21(a)(1) and therefore, should not have been included within the scope of license renewal to begin with. Therefore, the staff finds the applicant's decision to omit the solenoid valves from an AMR is acceptable.

Page 6.3-3 (Revision 18) of the UFSAR indicates that a small drain valve controlled remotely from the control room is intended to drain any leakage from the RCS into the SI system. NRC

Question No. 5.15.2 asked the applicant to indicate if this valve is subject to an AMR, and if it is, to cross-reference where this is addressed in Appendix A to the LRA; if it is not, to give the basis for its exclusion. The applicant responded by stating that the drain valves described above are associated with the SITs. The valves are pneumatically operated control valves 1(2)CV611, 1(2)CV621, 1(2)CV631, and 1(2)CV641. These valves are opened to allow draining RCS in-leakage to the SITs and are represented on Figure 5.15-1 of Appendix A to the LRA immediately to the left of the SIT. These valves were subjected to an AMR, and are considered in the SI portion of Appendix A to the LRA as control valves.

Page 6.3-14 (Revision 21) of the UFSAR indicates that the containment sump suctions are enclosed by particulate screens. NRC Question No. 5.15.3 asked the applicant to clarify whether these screens are subject to an AMR, and if they are, to cross-reference where they are addressed in Appendix A to the LRA; if they are not, to provide the basis for exclusion. The applicant stated in its response that the containment sump particulate screens are considered in Section 3.3A, "Primary Containment Structure," of Appendix A to the LRA, and that they are specifically identified on page 3.3A-6 under "Unique Components."

As described above, the staff has reviewed the information in Section 5.15 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified those portions of the SI system and the associated (supporting) structures and components that fall within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.28.2.2 Safety Injection Systems Subject to an Aging Management Review

The applicant described the components of the safety injection (SI) system that are subject to an AMR in Section 5.15.1.3 of Appendix A to the LRA. The applicant divided structures and components within the scope of license renewal into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.15-1 of Appendix A to the LRA). The staff reviewed the information to verify that the applicant's grouping was correct. As described in detail below, the staff finds that the applicant has made no omissions in classification. Therefore, the staff finds reasonable assurance that the applicant has identified the structures and components subject to an AMR for the SI system.

Of the 56 device types within the scope of the license renewal rule, 43 device types are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 43 components, the applicant classified the following 29 as having only active functions and, therefore, not requiring an AMR:

- circuit breaker
- disconnect switch/link
- fuse
- current/pneumatic device
- level indicator
- 4-kV motor
- 4-kV local control station (disconnect/link)
- solenoid valve
- power supply
- MOV operator
- coil
- voltage/current device
- flow device (relay)
- control valve operator
- flow indicator controller
- handswitch
- power lamp indicator
- level device (relay)
- solenoid
- temperature transmitter
- position indicating lamp
- level indicator alarm
- 125/250-V dc motor
- relay
- temperature recorder
- position indicator
- position transmitter
- ammeter
- position switch

The following nine device types are evaluated in Section 2.2.3.32, "Cables," or Section 2.2.3.35, "Instrumentation Lines," of this SER:

- pressure transmitter
- level switch
- level transmitter (except as noted below)
- flow indicator
- pressure indicator
- control/power cabling
- flow transmitter
- pressure switch
- instrument tubing/valve

The containment emergency sump level transmitters are being addressed separately as components that are subject to periodic replacement based on a qualified life or specified time period and do not require an AMR.

The following five electrical/instrumentation components evaluated in this section were classified as subject to an AMR (only pressure boundary/body):

- control valve
- temperature element
- flow element
- temperature indicator
- MOV

According to 10 CFR 54.21(a)(1), an AMR is required for long lived/passive components that perform an intended function without moving parts or are not subject to replacement based on a qualified life or specified time period. The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

Thirteen device types are mechanical components or structural components. Except for the refueling water tank heat exchanger (RWTHX), structural supports for piping, cables, and components are addressed in Section 2.2.3.1, "Component Supports" of this SER. The applicant included the RWTHX supports as a subcomponent of the HX. In addition, the expansion joint was evaluated in Section 2.2.3.4, "Primary Containment Structure," of this SER.

The remaining 11 device types listed in Table 5.15-1 are mechanical components that perform passive functions. The staff agrees with the applicant's inclusion of these devices as requiring an AMR. The 11 mechanical component device types requiring an AMR are identified as follows:

- Class CC piping
- Class DC piping
- Class GC piping
- Class HC piping
- Check valve
- flow orifice
- hand valve
- heat exchanger
- pump/driver assembly
- relief valve (RLV)
- tank

As discussed above, the staff has reviewed the information presented in Section 5.15 of Appendix A to the LRA and the additional information provided by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified and listed those structures and components subject to an AMR for the SI system to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.29 Saltwater System

In Section 5.16, "Saltwater (SW) System," of Appendix A to the LRA, the applicant described the SW system and identified the SW components that are within the scope of license renewal, and identified which of those within-scope components are subject to an AMR.

2.2.3.29.1 Summary of Technical Information in the Application

As described in the LRA, the SW system is a safety-related, open-loop cooling-water system designed to remove heat from various safety-related heat exchangers and coolers. Each unit has three SW pumps that provide the driving head to transport SW from the intake structure, through the system, to the circulating water discharge conduits. The system is designed so that each pump has sufficient head to provide adequate cooling water for the service water (SRW) system, component cooling (CC) system, and emergency core cooling system (ECCS) pump room coolers, as required by General Design Criterion 44 of 10 CFR Part 50, Appendix A.

The SW system for each unit consists of two subsystems. Each subsystem provides SW to an SRW heat exchanger, a CC heat exchanger, and an ECCS pump room air cooler in order to transfer heat from these heat exchangers and coolers to the Chesapeake Bay, which is the ultimate heat sink (UHS) for the plant. During normal operation, both subsystems in each unit are in operation with one pump running on each header and a third pump in standby. If needed, the standby pumps can be lined up to either supply header in their respective units. The SW flow through the SRW and CC heat exchangers is throttled to provide sufficient flow to the heat exchangers, while maintaining total subsystem flow below a maximum value.

Operation following a loss-of-coolant accident (LOCA) has two phases: before the recirculation actuation signal (RAS) and after the RAS. After a LOCA but before the RAS, each subsystem will cool an SRW heat exchanger and an ECCS pump room air cooler. Flow to the ECCS pump room cooler is initiated only if required because of high room temperature. There is no flow to the CC heat exchanger during this phase and system flow is not throttled.

When the RAS is received, the minimum required flow to each SRW heat exchanger is reduced, flow to the CC heat exchangers is restored, and the flow to the ECCS pump room coolers remains the same as it was before the RAS.

In identifying the scope of the SW system license renewal evaluation, the applicant made an exception to the LRA boundary convention. The SRW and CC heat exchangers were included in the scope of the SW system evaluation even though heat exchangers are normally considered part of the system they cool. This exception was made because age-related degradation is much more severe on the SW side of the heat exchangers.

In Appendix A to the LRA, the applicant identified the following intended functions for the SW system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Provide the vital auxiliary function of supplying cooling water to the CC and SRW heat exchangers and the ECCS pump room air coolers during design-basis events.
- Maintain electrical continuity or protect the electrical system or both.
- Maintain the pressure boundary of the system (liquid or gas).
- Restrict flow to a specified value in support of a DBE response.

The applicant also determined that the following were intended functions of the SW system based on the requirements of 10 CFR 54.4(a)(3):

- For post-accident monitoring—Provide information used to assess the plant and environs condition during and following an accident.
- For environmental qualification—Maintain functionality of electrical components as addressed by the environmental qualification (EQ) program.

- For fire protection—Provide the UHS for SRW and CC systems to ensure safe shutdown in the event of a fire.

On the basis of the intended functions listed above, the portions of the SW system that are identified by the applicant as within the scope of license renewal include the following components: SW pumps and motors; the SRW and CC heat exchangers; the ECCS pump room air coolers; air accumulators for control valves; and the associated piping, valves, instruments, and controls. The applicant identified a total of 40 device types from within these SW components as being within the scope of license renewal. Of these 40 device types, the applicant identified 20 that are subject to an AMR. The 20 device types are: 6 types of piping (6 different materials), 6 valve types (check, control, relief, solenoid, pressure control, and hand valve), heat exchanger, flow orifice, pump/driver assembly, accumulator, basket strainer, current-to-pneumatic transducer, temperature indicator, and temperature test point. The applicant noted that instrument line manual drain equalization, isolation valves, and some instrument test points are evaluated for the effects of aging in the instrument line commodity evaluation in Section 6.4, "Instrument Lines," of Appendix A to the LRA. The applicant further indicated that maintenance of the pressure boundary for the liquid or gas or both in the SW system and ability to restrict flow to a specified value in support of a design-basis event, are the only passive intended functions associated with the SW system that are not addressed in one of the commodity evaluations of the LRA.

As identified by the applicant, some components in the SW system are common to many systems and, therefore, have been included in the separate commodity report sections, which address those components for the entire plant. Hence, the following common components were not included in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated for the effects of aging in Section 3.1, "Components Supports," of Appendix A to the LRA;

- Electrical control and power cabling, which is evaluated in Section 6.1, "Cables," of Appendix A to the LRA; and

- Instrument tubing and piping and their associated supports, instrument valves and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4, "Instrument Lines," of Appendix A to the LRA.

2.2.3.29.2 Staff Evaluation

The staff reviewed Section 5.16 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has identified and listed the SW system components and supporting structures within the scope of license renewal per 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the SW system (NRC letters to BGE dated August 28 and September 24, 1998), and by letters dated November 2 and 12, 1998, the applicant responded to those RAIs.

2.2.3.29.2.1 Saltwater System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including the flow diagrams for the SW system, to determine if there were portions of the system piping and other components that the applicant did not identify as within the scope of license renewal. In the LRA, the applicant identified interface boundaries with six other systems. These six interfacing systems are the SRW system, the CC system, the auxiliary building heating and ventilation system (ECCS pump room coolers), the circulating water system, the compressed air system, and the engineered safety features actuation system (ESFAS). Most of the major SW system flow path piping and the interfaces with other systems are within the scope of license renewal. License renewal interface boundaries exist only at the interfaces with the circulating water system, which is not within the scope of license renewal. On the SW side of the interface boundary, the system piping and other components are within the scope of license renewal while on the other side of the interface boundary, (the circulating water side) the piping and other components are not within the scope of license renewal. The staff reviewed all the identified license renewal interface boundaries within the SW system in addition to all the identified interface boundaries with other systems, structures, and components. The staff also reviewed the system flow diagrams to verify that there were no significant interface boundaries that were not identified by the applicant in the LRA. If the portions of the SW system beyond the license renewal interface boundary (i.e., portions of the system that are not within the scope of license renewal) were verified by the staff to have no intended functions, then the components within those portions of the system were also deemed to have no intended function and were eliminated from further consideration. The staff also reviewed the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA to determine if there were any structures or components having intended functions that might have been omitted from consideration within the scope of license renewal. As described in detail below, the staff found no omissions and, therefore, concluded there was reasonable assurance that the applicant adequately identified those portions of the SW system and its associated (supporting) structures and components that fall within the scope of license renewal in accordance with 10 CFR Part 54.

In the LRA, the applicant indicated that the SW system at the interfaces with the circulating water system (CWS) pump seals and the CWS discharge conduits were not within the scope of license renewal. To help ensure that those portions of the SW system identified as not within the scope of license renewal at these interfaces did not perform any intended functions and, therefore, did not have any components subject to an AMR, the staff requested additional information from the applicant based on the information in the UFSAR and the LRA. Because the specific license renewal interface points were not depicted on the simplified drawing in the LRA, the staff asked the applicant to more clearly define these interfaces and describe the isolation capability at those interfacing points.

In its response to NRC Question No. 5.16.1, the applicant stated that the safety-related SW system discharges back to the Chesapeake Bay via non-safety-related CWS discharge conduits (two conduits per unit). The discharge conduits are not within the scope of license renewal because they do not meet any of the scoping criteria identified in 10 CFR 54.4. The interface is at an embedded spool piece that joins the safety-related discharge piping to the discharge conduits. As described in the applicant's response to NRC Question No. 5.16.2, an emergency discharge path is provided that is within the scope of license renewal in the event that the normal discharge path is failed. To use the emergency discharge path, one of the two discharge supply headers is required to be used as an alternate discharge flow path. The other license renewal interfaces with the CWS are in the piping to the CWS pump seals. The applicant stated that the interfaces are composed of safety-related flow orifices (two per unit) at the interfaces with the non-safety-related supply piping. These orifices are identified as within the scope of license renewal. On the basis of the applicant's responses and the supporting information in the UFSAR, the staff concluded that those portions of the SW system that are not identified as within the scope of license renewal do not perform any intended functions.

As described above, the staff has reviewed the information submitted in Section 5.16 of Appendix A to the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of that review, the staff finds that there is reasonable assurance that the applicant has appropriately identified the portions of the SW system and the associated structures and components thereof, that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.29.2.2 Saltwater System Subject to an Aging Management Review

In Section 5.16.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the saltwater (SW) system were within the scope of license renewal. The applicant categorized those structures and components into device types not subject to an AMR and device types subject to an AMR; the list appears in Table 5.16-1 of Appendix A to the LRA. The staff reviewed the information submitted by the applicant to verify that the applicant's grouping was correct. As described in detail below, the staff finds reasonable assurance that the applicant has identified the structures and components for the SW system that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

Of device types within the scope of the license renewal rule, 29 are electrical/ instrumentation components. The staff reviewed the device types that are electrical/ instrumentation components to verify that the applicant did not miss any electrical/ instrumentation components that should be subject to an AMR. Of the 29 components, the applicant classified the following 14 as having only active functions and, therefore, not requiring an AMR:

- coil
- fuse
- hand switch
- indicator controller
- hand switch ammeter
- power-indicator lamp

- level relay
- 4-kV motor
- motor-operated valve
- 4-kV local control station
- relay
- position-indicating lamp
- position switch
- temperature switch

The following seven components are evaluated under Section 2.2.3.32, “Cables,” and Section 2.2.3.35, “Instrument Lines,” in this SER:

- differential pressure indicator
- differential pressure indicating switch
- pressure switch
- pressure indicator
- pressure transmitter
- control/power cabling
- instrument tubing/valves

The following eight electrical/instrumentation components were classified as subject to an AMR (only pressure boundary/body):

- control valve
- current-to-pneumatic transducer
- solenoid valve
- temperature indicator
- flow element
- flow indicating controller
- pneumatic amplifier
- positioner

Some of the current to pneumatic transmitters and solenoid valves are periodically replaced based on qualified life or specified time period. Those current-to-pneumatic transducers and solenoid valves that are replaced periodically do not require an AMR.

The staff also reviewed the non-electrical components in the saltwater system in order to determine whether the applicant has properly identified the structures and components subject to an AMR. The following components were identified as subject to an AMR:

- piping
- accumulators
- basket strainers
- check valves
- flow orifices
- pressure control valve
- hand valves
- heat exchangers
- pump/driver assemblies
- relief valves
- temperature test points
- auto vent valve

The staff has reviewed the information in Section 5.16.1.3 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of the staff's review of the information submitted by the applicant, the staff has determined that there is reasonable assurance that the applicant has appropriately identified the structures and components in the saltwater system that are subject to an AMR as required under 10 CFR 54.21(a)(1).

2.2.3.30 Service Water System

In Section 5.17, "Service Water (SRW) System," of Appendix A to the LRA, the applicant described components and associated structures of the closed-loop SRW system that are within the scope of license renewal, and identified which of those components are subject to an AMR.

2.2.3.30.1 Summary of Technical Information in the Application

As described in the LRA, the SRW system in each unit is a closed-loop cooling-water system that supplies chemistry-controlled water during normal operation to two safety-related, seismic Category I trains and a non-safety-related nonseismic (i.e., turbine building) train. The safety-related trains supply cooling water to the spent fuel pool (SFP) heat exchanger, containment cooling units, blowdown recovery heat exchangers, and the emergency diesel generators (EDGs). The non-safety-related train supplies cooling water to various turbine building loads. The saltwater (SW) system (Section 5.16, "Saltwater System," of Appendix A to the LRA) provides the cooling medium for the SRW heat exchangers and discharges the heated water to the ultimate heat sink. The SRW system is required to operate during normal operation, plant shutdown, and post-accident conditions. The SRW system for each unit consists of three motor-driven pumps (one per train plus a swing pump), two heat exchangers, two head tanks, a chemical additive tank, associated valves, piping, instrumentation, and controls.

In Appendix A to the LRA, the applicant identified the following intended functions for the SRW system based on 10 CFR 54.4(a)(1) and 54.4(a)(2):

- Serve as a vital auxiliary to the ESFAS by processing signals, and as a vital auxiliary to the EDGs, SFP coolers, and containment coolers by providing cooling water.
- Provide seismic integrity or protection of safety-related components or both.
- Maintain electrical continuity and protect the electrical system.
- Maintain the pressure boundary of the system liquid.

The following intended functions of the SRW system were determined based on the requirements of 10 CFR 54.4(a)(3):

- For post-accident monitoring—Provide information used to assess the plant and environs condition during and following an accident.

- For equipment qualification—Maintain functionality of electrical components as addressed by the equipment qualification (EQ) program.

- For fire protection—Provide cooling water to the EDGs, containment coolers, and instrument air/plant air compressor loads to ensure safe shutdown in the event of a fire.

On the basis of the intended functions, the portions of the SRW system that are within the scope of license renewal include equipment types that consist of piping, heat exchangers, pumps, valves, tanks, supports, instrumentation, and cables for the portions of the system relied on for mitigation of design-basis events, for EQ purposes, and for safe shutdown following a fire. The applicant identified a total of 38 device types from within these SRW equipment types as being within the scope of license renewal. Of these 38 device types, the applicant identified the following 12 that are subject to an AMR: piping; 6 valve types (automatic vent, check, control, relief, solenoid, and hand valve); pump/driver assembly; radiation element; temperature element; temperature indicator; and tank. The applicant further indicated that maintenance of the pressure boundary liquid is the only passive intended function associated with the SRW system that is not addressed in one of the commodity evaluations of the LRA. Additionally, the SRW heat exchanger is evaluated in the SW system sections of the LRA and this SER.

2.2.3.30.2 Staff Evaluation

The staff reviewed Section 5.17 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has identified and listed the SRW system components within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs regarding the SRW system (NRC letter to BGE dated September 3, 1998), and by letter dated November 16, 1998, the applicant responded to those RAIs.

2.2.3.30.2.1 Service Water System Within the Scope of License Renewal

As part of the first step of its evaluation, the staff reviewed portions of the UFSAR, including flow diagrams for the SRW system, to determine if there were any portions of the system, and associated structures and components, that the applicant did not identify as within the scope of license renewal. In the LRA, the applicant identified a number of license renewal interface boundaries within the SRW system. A license renewal interface boundary usually exists at a point in the system piping where non-safety-related portions of the system interface with safety-related portions. A license renewal interface exists at the same location as the safety-related/non-safety-related interface because the non-safety-related portions of the system do not perform any intended functions and the safety-related portions perform at least one intended function. Appropriate isolation capability that is part of the existing licensing and design basis for the system is provided at each of these interfaces. That isolation capability was not reevaluated for license renewal because it is part of the current licensing basis and was previously approved by the staff.

However, the staff did verify that the components performing the isolation capability were identified by the applicant as being within the scope of license renewal. Interface boundaries also exist in which the SRW system interfaces with other systems through various components such as heat exchangers, equipment cooling coils, or head tank fill piping. The staff reviewed all the identified license renewal interface boundaries within the SRW system in addition to all the identified interface boundaries with other systems, structures, and components. The staff also reviewed the system flow diagrams to verify that there were no significant interface boundaries that were not identified by the applicant in the LRA. If the portions of the SRW system beyond the license renewal interface boundary (i.e., portions of the system that are not identified as within the scope of license renewal) were verified by the staff to have no intended functions, then the components within those portions were also eliminated from further consideration. The staff also reviewed the UFSAR to determine if there were any intended functions that were not identified in the LRA to verify if there were any structures and components having intended functions that might have been omitted from consideration within the scope of license renewal. As described in detail below, the staff found only one significant omission. The staff determined that a nonseismic, non-safety-related SRW (turbine building) header was not identified as within the scope of license renewal. The staff also determined that the turbine building header integrity was necessary to allow the safety-related portion of the SRW system to perform its intended function. Therefore, the staff concluded that the components of this non-safety-related header, which are necessary to maintain the header integrity following a seismic event, should be within the scope of license renewal pursuant to 10 CFR 54.4(a)(2) there is reasonable assurance that the applicant adequately identified all the other portions of the SRW system and associated (supporting) structures and components that fall within the scope of license renewal in accordance with 10 CFR Part 54.

Because of its function as a cooling-water supply, the SRW system interfaces with 25 other systems on Unit 1 and 23 systems on Unit 2. Seven of the interfacing systems at each unit are within the scope of license renewal. At both units, 6 of the 7 interfacing systems that are within the scope of license renewal are served by the safety-related headers; the remaining interfacing system (instrument/plant air compressors and aftercoolers) that is within the scope of license renewal is supplied cooling water from the non-safety-related turbine building header. The remaining components that are not within the scope of license renewal (18 for Unit 1, 16 for Unit 2) are supplied cooling water from the non-safety-related turbine building SRW header. The non-safety related turbine building header is isolated from the safety-related portion of the SRW system by safety-related boundary valves during a safety injection actuation signal. The staff reviewed the interfaces and found that the applicant has identified all of the significant interfaces based on the information available in the UFSAR and the flow diagrams.

In Appendix A to the LRA, the applicant stated that the non-safety-related turbine building header did not perform any of the intended functions based on the requirements of 10 CFR 54.4(a)(1) or 54.4(a)(2), but only performed an intended function based on 10 CFR 54.4(a)(3) for fire protection. The applicant also stated that the turbine building header isolation valves close on a safety injection actuation signal (SIAS), but the valves do not close automatically upon a seismic event (or pipe break). As a result, the applicant determined that a postulated SRW system pipe rupture (initiated by a seismic event) in the turbine building could render both safety-related (auxiliary building) SRW trains inoperable if it were to occur. To preclude such a failure, the applicant evaluated the SRW system in the turbine building and, after some minor modifications, concluded that the non-safety-related portions of the SRW system are rugged enough to withstand a design-basis earthquake.

Since the non-safety-related header is credited with preserving cooling water inventory in the safety-related portions of the SRW system following a seismic event, the staff asked (NRC Question No. 5.17.1) the applicant to clarify why the turbine building header piping is not within the scope of license renewal [in accordance with 10 CFR 54.4(a)(2)]. In its response, the applicant reiterated that the turbine building SRW system components do not meet 10 CFR 54.4(a)(1) or 54.4(a)(2) scoping requirements, and cited four references: the UFSAR; Licensee Event Report (LER) 89-03, Revision 2; a BGE letter dated October 16, 1995; and NRC Inspection Report Nos. 50-317/95-08 and 50-318/95-08. The applicant further indicated that the turbine building header was discussed in the fire protection section (Section 5.10, "Fire Protection") of Appendix A to the LRA only because it has intended functions related to 10 CFR 54.4(a)(3) for safe shutdown from postulated fires. The staff reviewed the applicant's response, including the cited references, and found no new information that would support the applicant's conclusion that the turbine building header did not meet the scoping requirements of 10 CFR 54.4(a)(2). In fact, it was the staff's opinion that the information in the cited references reinforced the staff's conclusion that the turbine building header should be within the scope of license renewal based on 10 CFR 54.4(a)(2) because a loss of the turbine building header pressure boundary could result in a failure (loss of inventory) of the safety-related portions of the SRW system (portions within the scope of license renewal) to provide cooling water to the emergency diesel generators, spent fuel pool coolers, and containment coolers, which is an intended function of the SRW system pursuant to 10 CFR 54.4(a)(1). This issue was identified as Open Item 2.2.3.30-1 in the previous SER.

After further review, the applicant informed the staff in a letter dated April 2, 1999, that it is including the non-safety-related SRW turbine building header within the scope of license renewal. Including the components associated with the non-safety-related SRW turbine building header within the scope of license renewal addresses the staff's concerns and closes Open Item 2.2.3.30-1.

As described above, the staff has reviewed the information presented in Section 5.17 of Appendix A to the LRA, the additional information sent by the applicant in response to the staff's RAIs, and the letter dated April 2, 1999, and finds reasonable assurance that the applicant has appropriately identified the portions of the SRW system and the structures and components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.30.2.2 Service Water System Subject to an Aging Management Review

In Section 5.17.1.2 of Appendix A to the LRA, the applicant identified which structures and components of the service water system were within the scope of license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.17-2, "Device Types Requiring an AMR for Service Water System," of Appendix A to the LRA). The staff reviewed the information sent by the applicant to verify that the grouping was correct. As described below, the staff finds that there is reasonable assurance that the applicant has identified the structures and components subject to an AMR for the service water system in accordance with 10 CFR 54.21(a)(1).

Of the device types within the scope of the license renewal rule, 32 device types are electrical/ instrumentation components. The staff reviewed the device types that are electrical/ instrumentation components to verify that the applicant did not miss electrical/instrumentation components that should be subject to an AMR. Of the 32 device types, the applicant classified the following 16 as having only active functions and, therefore, not requiring an AMR:

- voltage/current device
- flow indicator
- position-indicating lamp
- hand switch
- position switch
- pressure indicator
- power light indicator
- ammeter
- level switch
- fuse
- relay
- 4-kV motor
- 125/250-V dc motor
- coil
- power supply
- temperature-indicating alarm

The following eleven components are evaluated under Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrumentation Lines," of this SER.

- flow transmitter
- level gauge
- level transmitter
- panel
- pressure switch
- pressure transmitter
- 4-kV local control station
- control/power cabling
- 125/250-V dc local control station
- instrument tubing/valves
- pressure differential indicating controller

The following five electrical/instrumentation components were classified as subject to an AMR (only pressure boundary/body):

- control valve
- flow element
- temperature element
- temperature indicator
- radiation element

Nine device types within the scope of license renewal are mechanical components or structural supports. The structural supports for piping, cables and components are evaluated in Section 2.2.3.1, "Component Supports," and heat exchangers are evaluated in Section 2.2.3.29.2.2, "Saltwater System Subject to an Aging Management Review," of this SER.

The remaining seven device types are piping and mechanical components that perform passive functions:

- piping
- check valves
- flow orifices
- hand valves
- pump/driver assemblies
- relief valves
- tanks

The staff has reviewed the information presented in Section 5.17 of Appendix A to the LRA and has determined that there is reasonable assurance that the applicant has identified the portions of the SRW within the scope of license renewal as required under 10 CFR 54.4 (a)(1), and has identified the structures and components subject to an AMR for the SRW as required under 10 CFR 54.21(a)(1).

2.2.3.31 Spent Fuel Pool Cooling System

In Section 5.18 "Spent Fuel Pool Cooling System (SFPCS)" of Appendix A to the LRA, the applicant described the technical information related to structures and components of the SFPCS at the plant site that are within the scope of license renewal, and identified which of those structures and components are subject to an AMR.

2.2.3.31.1 Summary of Technical Information in the Application

The primary functions of the SFPCS are to remove decay heat from the spent fuel stored in the spent fuel pool (SFP); to provide cooling for the refueling pools; to maintain clarity and low activity in the SFP, in the refueling pools, and in the refueling water storage tanks; and to transfer water within the systems. The SFPCS consists of two half-capacity pumps and two half-capacity heat exchangers in parallel, a bypass filter that removes insoluble particulates, a bypass demineralizer for removing soluble ions, and various piping, valves, and instrumentation. The SFP itself is divided in two halves, each serving one reactor unit. Both new and spent fuel can be stored in the spent fuel pool. The SFP structure is located in the auxiliary building and is evaluated in Section 3.3, "Structures," of Appendix A to the LRA. The system contains the following major components: piping, valves, instrumentation, a filter, a strainer, a demineralizer, pumps, and heat exchangers.

Structures and Components Subject to an Aging Management Review

In the LRA, the applicant identified the following intended functions for the SFPCS based on 10 CFR 54.4(a)(1) and (2):

- Provide containment isolation for a loss-of coolant accident or a control rod ejection event.
- Provide heat removal for SFP water and refueling pool water after a fuel handling accident or a boron dilution event.
- Maintain the pressure boundary of the system.
- Maintain the electrical continuity and provide protection of the electrical system.

The applicant did not identify any intended functions for the SFPCS based on 10 CFR 54.4(a)(3).

On the basis of the intended functions listed above, the following portions of the SFPCS were identified by the applicant as within the scope of license renewal: all components and supports from the refueling and spent fuel pools through the SFP cooling pumps, the heat exchanger's filter and demineralizer, and back to the refueling and spent fuel pools. Interfacing system isolation valves are also within the scope. The applicant identified the following equipment types and devices as being within the scope of license renewal: piping, valves, instrumentation, filters/strainers, demineralizer, pumps, and heat exchangers. The applicant identified a total of 28 device types from within these equipment types and devices as being within the scope of license renewal. Of these 28 device types, the applicant identified the following 14 device types that are subject to an AMR: piping, strainers (2), check valve, relief valve, hand valve, flow element, filter, flow orifice, heat exchanger, demineralizer, pump assembly, temperature indicator, and temperature switch.

The applicant also indicated that some components in the SFPCS that are common to many systems have been evaluated in the separate commodity reports that address those components for the entire plant. Therefore, the following components were not discussed in the individual system sections:

- Structural supports for piping, cables, and components, which are evaluated in Section 3.1 of Appendix A to the LRA. However, supports for the filter and demineralizer were addressed in this section.
- Electrical control and power cabling, which is evaluated in Section 6.1 of Appendix A to the LRA.

- Instrument tubing and piping and their associated supports, instrument valves, and fittings, and the pressure boundaries of the instrument themselves, which are all evaluated in Section 6.4 of Appendix A to the LRA.

2.2.3.31.2 Staff Evaluation

The staff reviewed Section 5.18 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has identified the SFPCS components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1) and (2). After completing the initial review, by letter dated September 1, 1998, the staff issued a request for additional information (RAI) regarding the SFPCS, and by letter dated November 17, 1998, the applicant responded to the RAI.

2.2.3.31.2.1 SFPCS Structures and Components Within the Scope of License Renewal

As part of its evaluation, the staff reviewed Chapter 9.4 of the UFSAR, including the flow diagrams for the SFPCS, to determine if there were any additional portions of the SFPCS piping or other components that the applicant should have identified as within the scope of license renewal. Essentially all portions of the SFPCS were determined to perform at least one intended function and, therefore, essentially all portions and components of the SFPCS are within the scope of license renewal and are identified as such by the applicant either in Section 5.18 or in other sections of the LRA. The staff reviewed the few remaining components of the SFPCS to verify that they do not have any intended functions. The staff also reviewed portions of the UFSAR for any safety-related system functions that were not identified as intended functions in Appendix A to the LRA to verify that no structures and components having an intended function were omitted from within the scope of the rule. As described below, the staff found no omissions of components or intended functions and, therefore, concluded that there is reasonable assurance that the applicant adequately identified those portions of the SFPCS and the associated components and structures that fall within the scope of license renewal in accordance with 10 CFR Part 54.

The staff review of the UFSAR and flow diagrams did not reveal any additional structures or components of the SFPCS that should be within the scope of license renewal. Essentially all of the components of the SFPCS are within the scope of license renewal. However, the staff did request additional information in NRC Question Nos. 5.18.1, 5.18.2, and 5.18.3 to help ensure there were no omissions from the applicant's list of components within the scope of license renewal.

Figure 5-18.1 of Appendix A to the LRA is a simplified drawing that identifies the SFPCS boundary for the SFPCS and appeared to the staff to include several pipe segments downstream of boundary valves within the scope of license renewal. Because this piping has no isolation capability, the staff asked the applicant to clarify whether this piping was within the scope of license renewal. In its response to the staff dated November 17, 1998, the applicant stated that the piping segments were within the scope of license renewal because they provide structural support for the boundary valves and that the piping segments were evaluated in Section 3.1A of Appendix A to the LRA. Likewise, the staff questioned whether other components (e.g., instrument air lines, spool pieces) identified on Figure 5-18.1 had been omitted. In its response, the applicant verified that each component was either outside the scope of license renewal or was within the scope of license renewal and evaluated in another section of the LRA. The staff reviewed the applicant's response and agreed that the components either performed no intended function and were not within the scope of license renewal or were addressed in another part of the LRA.

As a result of its review, the staff also did not identify any additional intended functions that could result in additional components (components not identified by the applicant) being within the scope of license renewal.

As described above, the staff has reviewed the SFPCS information submitted in Section 5.18 of Appendix A to the LRA and the additional information submitted by the applicant in response to the staff's RAI. On the basis of this review, the staff finds reasonable assurance that the applicant has appropriately identified those SFPCS structures and components within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.31.2.2 Spent Fuel Pool Cooling System Subject to an Aging Management Review

The staff focused its review of this area on whether the applicant has properly identified the structures and components subject to an AMR from among the systems, structures, and components that have been identified within the scope of license renewal. The staff reviewed selected structures and components identified by the applicant as within the scope of license renewal to verify that they have been identified as subject to an AMR if they perform an intended function without moving parts or without a change in configuration and properties and are not subject to replacement based on a qualified life or specified time period.

In Section 5.18.1.2 of Appendix A to the LRA, the applicant identified the structures and components of the spent fuel pool cooling system (SFPCS) that are within the scope of license renewal. The applicant divided those structures and components into device types not subject to an AMR and device types subject to an AMR (listed in Table 5.18-2, "Device Types Subject to an AMR"). The staff reviewed the information submitted by the applicant to verify that the grouping was correct. As described below, the staff finds no omissions in classification. Therefore, the staff finds reasonable assurance that the applicant has identified the structures and components subject to an AMR for the SFPCS.

Of 31 device types within the scope of the license renewal rule, 19 are electrical/instrumentation components. The staff reviewed the device types that are electrical/instrumentation components to verify that the applicant did not omit electrical/instrumentation components that should be subject to an AMR. Of the 19 components, the applicant classified the following 8 as having only active functions and, therefore, not requiring an AMR:

- coil
- power lamp indicator
- 480-V motor
- 125/250-V dc motor
- fuse
- position-indicating lamp
- relay
- hand switch

The following eight components are evaluated in Section 2.2.3.32, "Cables"; Section 2.2.3.33, "Electrical Commodities"; or Section 2.2.3.35, "Instrument Lines," of this SER.

- flow indicator
- flow indicator switch
- pressure differential indicator
- pressure indicator
- control/power cabling
- pressure differential indicator switch
- pressure switch
- instrument tubing/valves

Three electrical/instrumentation components (flow element, temperature indicator, and temperature switch) were classified by the applicant as subject to an AMR (only pressure boundary/body). In the previous SER, the staff concluded that temperature switches were active devices and therefore need not be subject to an AMR. After further review, the staff concludes that the "pressure boundary/body" portions of temperature switches are correctly classified as subject to an AMR.

Twelve device types within the scope of license renewal are mechanical components or structural components. The structural components for piping, cables, and components are evaluated in Section 2.2.3.1, "Component Supports," of this SER.

The remaining 11 device types listed in Table 5.18-2 are piping and mechanical components that perform passive functions. The staff agrees with the applicant's inclusion of these devices as requiring an AMR.

The staff has reviewed the information in Section 5.18 of Appendix A to the LRA, and determined there is reasonable assurance that the applicant has appropriately identified the structures and components within the scope of license renewal and those that are the structures and components subject to an AMR for the SFPCS to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.32 Cables

In Section 6.1, "Cables," of Appendix A to the LRA, the applicant identified cables that are within the scope of license renewal, and identified those that are subject to an AMR.

2.2.3.32.1 Summary of Technical Information in the Application

The population of cables includes scheduled and unscheduled cables in power, control, and instrumentation circuits. Scheduled cables are those cables that are maintained as line items in the cable and raceway system (CRS) database. Unscheduled cables are internal panel wiring, equipment pigtails and terminal wiring, field installed jumpers, and some non-safety-related cabling. Cable insulation types for scheduled cables include silicone rubber, ethylene propylene rubber (EPR), crosslinked polyethylene (XLPE), crosslinked polyolefin (XLPO), mineral, Kapton, polyvinyl chloride, Teflon, and other miscellaneous insulation types. Tefzel-insulated wiring is also used as the currently approved safety-related internal wiring in the main control boards.

For efficiency in presenting the evaluation findings in the LRA, the cables have been assigned to the following groups: (Note: The cables in Groups 1 through 6 have an insulation rating of 90°C or higher.)

- Group 1—Includes thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing.
- Group 2—Includes thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing.
- Group 3—Includes synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside the containment.
- Group 4—Includes thermal aging for EPR non-EQ cables in power service, associated with the saltwater system and service water system 4-kV pump motor terminations.
- Group 5—Includes insulation resistance reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable insulation resistance.
- Group 6—Includes "treeing" (a form of voltage-induced degradation that causes hollow microchannels in the cable insulation to grow in a tree-like pattern) for EPR non-EQ cables in 4-kV power service.

2.2.3.32.2 Staff Evaluation

The staff reviewed Section 6.1 of Appendix A to the LRA to determine if there is reasonable assurance that the applicant has identified and listed those cables within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1). After completing the initial review, by letter dated July 9, 1998, the staff issued requests for additional information (RAIs). By letter dated September 17, 1998, the applicant responded to the staff's RAIs.

2.2.3.32.2.1 Cables Within the Scope of License Renewal

In the first step of the staff evaluation, the staff determined whether the applicant has properly identified the systems, structures, and components within the scope of license renewal. The applicant chose to evaluate cables as a "commodity" in accordance with the applicant's IPA methodology described in Section 2.0 of Appendix A to the LRA. Cables are associated with equipment in almost every plant system. The applicant's equipment database does not contain specific equipment connection information for individual cables. Instead, a separate cable and raceway system (CRS) database contains information on the scheduled cables, their service function (power, control, or instrumentation), their materials, and their routing. Cable schemes can then be correlated to individual raceways, equipment, and rooms, using the information on individual cables and the system non-specific nature of plant cabling.

The conceptual boundary (i.e., all cables in the CRS database) includes cables that are covered by the applicant's EQ program (10 CFR 50.49), as well as non-EQ cables. This is all-encompassing.

Cables that satisfy either of the following conditions are considered to be within the scope of license renewal:

- Any cable associated with a safety-related load or a load whose failure could prevent operation of a safety function; and
- Any cable associated with equipment relied upon for response to the regulated events in 10 CFR 54.4(a)(3) if the plant-specific evaluation for these events requires such cables to supply power to the load as part of the event response.

Cables were excluded from the scope of license renewal if they met any of the following conditions:

- Cable schemes associated with systems having no license renewal functions;
- Cable schemes that are non-safety-related and are associated with systems that do not support any non-safety-related license renewal functions;
- Cable schemes for annunciator circuits that do not support any events regulated under 10 CFR 54.4(a)(3);
- Cable schemes that have been spared (i.e., no longer perform any function); or
- Cable schemes that do not support a license renewal function as determined by specific examination of connection drawings and schematics.

As described above, the staff has reviewed information in Section 6.1 of Appendix A to the LRA and additional information sent by the applicant in response to the staff's RAIs and found no omissions. On the basis of the review of cables as a commodity group, the staff finds reasonable assurance that the applicant has appropriately identified the components (cables) within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.32.2.2 Cables Subject to an Aging Management Review

In the second step of the staff's evaluation, the staff determined whether the applicant had properly identified the components (cables) subject to an AMR that had been identified as within the scope of license renewal. The staff reviewed the selected components (cables) identified by the applicant as within the scope of license renewal to verify that they had been identified as subject to an AMR if they perform an intended function without moving parts or without a change in configuration and properties and are not subject to replacement on the basis of a qualified life or specified time period. However, internal panel wiring that is within the scope of license renewal was determined not to require an AMR on the basis that it is not exposed to high temperature or high radiation levels that can cause aging, which could affect the functionality of the wiring during the period of extended operation. An exception is the polyolefin insulated wiring in motor control centers that are subject to plausible thermal degradation (see Section 3.12.3.2.4 of the SER). Therefore, the staff concluded there is reasonable assurance that the applicant has identified the components (cables) subject to an AMR.

The staff has reviewed the information presented in Section 6.1 of Appendix A to the LRA and additional information sent by the applicant in response to the staff's RAIs. On the basis of the staff's review of cables that have been evaluated as a "commodity," the staff has determined there is reasonable assurance that the applicant has appropriately identified all non-EQ cables subject to an AMR to comply with the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.33 Electrical Commodities

In Section 6.2, "Electrical Commodities," of Appendix A to the LRA, the applicant described those systems containing electrical commodities that are within the scope for license renewal, and identified those components that are subject to an AMR.

2.2.3.33.1 Summary of Technical Information Regarding in the Application

Electrical components (e.g., panels, cabinets, and cables) are associated with most plant systems. During the scoping process performed for each system within the scope of license renewal, the applicant identified passive electrical structural enclosures and supports for 28 systems. Since many of these structural components and supports are made from similar materials and are located in environments common to numerous systems, the applicant used a commodity approach to evaluate these electrical components for AMR instead of addressing each component separately in individual system evaluations.

Electrical commodities (ECs) are within the scope of license renewal when they support and protect plant electrical components that are required to perform functions described in 10 CFR 54.4(a)(1), (2), and (3). During the applicant's implementation of the CCNPP integrated plant assessment (IPA) methodology, system components were assigned to the electrical commodities evaluation (ECE) during the system pre-evaluation process. As a result of this evaluation, several types of passive, long-lived electrical components were considered electrical commodities. The components fell into two categories: (1) conductive equipment and (2) panels and cabinets that provide support and protection for safety-related electrical equipment. The applicant identified the following eight structural enclosures during the ECE:

- miscellaneous panels
- motor control center cabinets
- switchgear/disconnect cabinets
- bus cabinets
- circuit breaker cabinets
- local control station panels
- battery terminal and charger cabinets
- inverter cabinets

Cables were excluded from the EC evaluation, but they are addressed in the cable commodities evaluation in Section 6.1 of Appendix A to the LRA. For the purpose of license renewal, panels and cabinet subcomponents, such as terminal blocks and other structural components that are attached to the cabinet or panel, are considered to be part of the cabinet or panel that houses them and are included in the ECE.

The applicant determined that in all cases, the passive intended function of the electrical commodities within the scope of license renewal is to provide structural support to active system components contained in the equipment, or to ensure electrical continuity of power, control, or instrumentation signals for safety-related components. The applicant identified the conceptual boundaries of electrical commodities to include panels and the enclosures for motor control centers, switchgear, buses, disconnect switches, links, local control stations, batteries, chargers, and inverters for the 28 systems identified in Table 6.2-1. All of these panels and enclosures or supports perform passive intended functions and are subject to an AMR.

On this basis, the electrical commodities that support passive functions that are long-lived are subject to an AMR. The electrical commodities enclosure device types that are subject to an AMR are identified in Table 6.2-2 of Appendix A to the LRA, and are listed below:

- battery terminals
- circuit breaker cabinets
- electrical bus cabinets
- charger cabinets
- disconnect switch/links cabinets
- inverter cabinets
- MCC cabinets
- 4-kV local control station panel
- 480-kV local control station panel
- 125/250-V dc local control station panels
- other panels

2.2.3.33.2 Staff Evaluation

The staff reviewed Section 6.2 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has identified the electrical commodities within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff met with the applicant on February 18, 1999, to discuss the review and to request additional information related to electrical commodities (NRC meeting summary dated March 19, 1999).

2.2.3.33.2.1 Electrical Commodities Within the Scope of License Renewal

The staff previously reviewed and accepted the applicant's integrated plant assessment methodology, which included a methodology to scope electrical commodities, and documented staff findings in "Final Safety Evaluation Concerning the Baltimore Gas and Electric Company Report Titled: 'Integrated Plant Assessment Methodology'," dated April 4, 1996. To determine whether there is reasonable assurance that the applicant identified the electrical components that are required to perform the intended functions described in 10 CFR 54.4, the staff performed the following reviews.

The applicant stated that the conceptual boundary for the electrical commodities includes panels and enclosures for electrical components in the 28 systems listed in Table 6.2-1 of Appendix A to the LRA. The staff compared the list of systems in Table 6.2-1 to the systems that are within the scope of license renewal to determine whether the applicant omitted any systems that might contain electrical commodities when compiling its list of systems to evaluate. As a result of its evaluation, the staff found eight systems within the scope of license renewal that were not identified in Table 6.2-1: for example, the safety injection system and the spent fuel pool cooling system.

In a meeting with the applicant on February 18, 1999, the applicant was asked to submit additional information explaining why these systems were not included in Table 6.2-1. As documented in the NRC meeting summary dated March 19, 1999, the applicant responded that some of the system's electrical components (e.g., panels) are associated with the components of other systems in the plant equipment database. This grouping of electrical components, along with evaluating cables as a commodity group, can result in systems within the scope of license renewal that are not listed in Table 6.2-1. The applicant responded that although the eight systems identified by the NRC are not in Table 6.2-1, the electrical components that support those systems are included in the electrical commodity evaluation and are within the scope of license renewal. The staff reviewed the applicant's response, and concluded the applicant's method for scoping electrical commodities was acceptable for identifying S&Cs within the scope of license renewal.

On the basis of its review, the staff finds reasonable assurance that the electrical commodity evaluation described in Section 6.2 of Appendix A to the LRA has appropriately identified the electrical structural components (e.g., panels, enclosures, supports) within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.33.2.2 Electrical Commodities Subject to an Aging Management Review

In the second step of its evaluation, the staff determined whether the applicant has properly identified the structures and components subject to an AMR from among the systems, structures, and components that have been identified as within the scope of license renewal. The staff reviewed selected structures and components identified by the applicant as within the scope of license renewal to verify that they have been identified as subject to an AMR if they perform an intended function without moving parts or without a change in configuration and properties and are not subject to replacement based on a qualified life or specified time period.

In Section 6.2.1.1 of Appendix A to the LRA, the applicant identified which electrical structural enclosures/supports (panels, racks, etc.) for motor control centers, switchgears, buses, disconnect switches/links, local control stations, batteries, chargers, and inverters from numerous systems (listed in Table 6.2-1) are within the scope of license renewal, are included in the electrical commodities evaluation (ECE), and are subject to an AMR. The applicant also identified terminal blocks and other structural subcomponents of enclosures as requiring an AMR.

The staff reviewed the electrical structural enclosures/supports and enclosure subcomponents that are electrical/instrumentation components to verify that the applicant did not omit any electrical/instrumentation components that should be subject to an AMR. The electrical/ instrumentation subcomponents evaluated in this section and classified as subject to an AMR were terminal blocks, insulating standoff supports for buses, organic insulation of wiring, and PVC boots for insulating 4-kV bus splices. Two of these subcomponents, polyolefin insulated wiring in 480-V AC MCCs and PVC boots in 4-kV switchgear cabinets, are evaluated in Section 2.2.3.32, "Cables," of this SER. Two subcomponents, terminal blocks and insulating standoff supports for buses in the housing/cabinets, evaluated in this section were classified as subject to an AMR. The staff agrees with the applicant's determination, which is consistent with 10 CFR 54.21(a)(1).

In other sections (such as Section 4.1.1.2) of Appendix A to the LRA, the applicant stated that certain devices types from the systems are evaluated in Section 6.2, "Electrical Commodities." In the previous safety evaluation, the staff determined from a review of Table 6.2-1 that not all systems that the applicant identified as cross-referenced to Section 6.2 are included therein. Also the applicant included in Table 6.2-1 systems (such as the saltwater system) whose corresponding sections in the application did not refer to Section 6.2 for evaluation of electrical commodity device types. These inconsistencies in documenting the systems containing electrical panels resulted in questions about the accuracy of Table 6.2-1. In the previous SER, the staff identified the documentation issues as Open Item 2.2.3.33.2.2-1.

In a letter dated July 2, 1999, the applicant presented the following clarification of the information contained in Table 6.2-1. The applicant stated that it re-verified the completeness of Table 6.2-1 and found that three systems (chemical and volume control, CEA Drive mechanism & electrical, and fire and smoke detection) needed to be added to the table. The applicant also re-verified the cross-referencing information presented in column 3 of Table 6.2-1 and found it accurate. In addition, in a follow-up letter dated September 28, 1999, the applicant sent information that identified the sections of the LRA that incorrectly referenced Section 6.2 and the sections of the LRA that should have referenced 6.2, but did not. The staff reviewed the additional information contained in the July 2 and September 28, 1999 letters and has reasonable assurance that the applicant has accounted for all systems in the LRA with electrical commodities and has made the appropriate cross-references to the electrical commodities section for evaluation.

On the basis of the review of the information presented by the applicant in the LRA and the letters dated July 2 and September 28, 1999, the staff has reasonable assurance that all systems containing electrical panels within the scope of the electrical commodities evaluation are identified on Table 6.2-1. This closes Open Item 2.2.3.33.2.2-1.

The staff has reviewed the information in Section 6.2 of Appendix A to the LRA, letters dated July 2 and September 28, 1999, and additional information submitted by the applicant in response to the staff's RAIs. The staff has determined that there is reasonable assurance that the applicant has appropriately identified the structures and components subject to an AMR for the electrical commodities to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.34 Environmentally Qualified Equipment

In Section 6.3, "Environmentally Qualified Equipment," of Appendix A to the LRA, the applicant described environmentally qualified (EQ) equipment that is within the scope for license renewal, and identified equipment that is subject to an AMR for license renewal.

2.2.3.34.1 Summary of Technical Information in the Application

In section 6.3 of Appendix A to the LRA, the applicant specifically addresses the EQ portion (10 CFR 50.49) of 10 CFR 54.4(a)(3). During the scoping process to determine structures and components subject to an AMR, any structures or components (including those designated as SR-5049 on the CCNPP quality list) that are replaced at intervals shorter than 40 years, are excluded from an AMR under 10 CFR 54.21(a)(1)(ii). Those EQ devices with qualified lives greater than or equal to 40 years were included on the list of structures or components subject to an AMR, in accordance with 10 CFR 54.4(a)(3), and have been designated by the applicant for evaluation in the LRA. In this regard, an EQ device may have intended functions in the scope of license renewal that are not managed by the EQ program. For example, a normally open solenoid valve may have an EQ function of closure under DBE conditions, and a pressure-retaining license renewal function. Of the 25 device types listed on the EQ master list, only the following 8 were determined to be subject to an AMR:

- cables (CBL)
- seal (SEAL)
- junction box (WRNMS)
- core exit thermocouple system (RI)
- containment penetration assembly (PEN)
- solenoid valve (SV)
- terminal block
- reactor level vessel monitoring system in-core assembly

Active device types and short-lived device types (requiring periodic replacement of device or worn device parts) are not subject to an AMR.

2.2.3.34.2 Staff Evaluation

The staff reviewed Section 6.3 of Appendix A to the LRA to determine if there is reasonable assurance that the applicant has identified and listed those EQ device types within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR to meet the requirements stated forth in 10 CFR 54.21(a)(1).

2.2.3.34.2.1 Environmentally Qualified Equipment Within the Scope of License Renewal

In the first step of the staff's evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal. The staff confirmed that those passive EQ devices that meet the criteria under 10 CFR 54.4(a) were included within the scope of license renewal. On the basis of the staff's review of the summary of EQ device types within the scope of license renewal as listed in Table 6.3-1 of the LRA, the staff finds that there is reasonable assurance that the applicant has appropriately identified all EQ components as being within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.34.2.2 Environmentally Qualified Equipment Subject to an Aging Management Review

In the second step of the evaluation, the staff determined whether the applicant had properly identified the EQ components subject to an AMR that have been identified as within the scope of license renewal. The staff reviewed the selected EQ components identified by the applicant as within the scope of license renewal to verify that they have been identified as subject to an AMR if they perform an intended function without moving parts or without a change in configuration and properties and are not subject to replacement on the basis of a qualified life or specified time period. The staff agrees that of the 25 EQ device types listed in Table 6.3-1 of the application, only 8 were determined to be subject to an AMR. The remaining 17 device types were determined to be active and not subject to an AMR. The 8 EQ device types subject to an AMR are cables, seals, junction boxes, solenoid valves, terminal blocks, core exit thermocouple system, containment penetration assembly, and reactor vessel level monitoring system in-core assembly. The staff concluded that there is reasonable assurance that the applicant has identified the EQ components subject to an AMR.

The staff has reviewed the information presented in Section 6.3 of Appendix A to the LRA for EQ components subject to an AMR, and has determined that there is reasonable assurance that the applicant had appropriately identified the EQ components subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.3.35 Instrument Lines

In Section 6.4, "Instrument Lines," of Appendix A to the LRA, the applicant described those systems containing instrument lines that are within the scope of license renewal and identified those components that are subject to an AMR.

2.2.3.35.1 Summary of Technical Information in the Application

An instrument line consists of those components associated with plant instrumentation located downstream of the process root valve. The process root valve is the first hand valve off the main process line or vessel and it is evaluated along with the process system. In cases in which piping class considerations require two root valves, the instrument line begins at the exit of the root valve most removed from the process.

Instrument lines have the following components, depending on their application:

- small-bore piping or tubing,
- hand valves, and
- components associated with the instrument that contributes substantially to maintaining the pressure-retaining boundary function of the instrument line (e.g., connected instruments, supports for instruments).

Instrument lines are associated with most plant systems. They maintain the system pressure boundary and are constructed of the same basic materials regardless of the system within which they are installed. For this reason, the commodity evaluation approach was used to evaluate these components, rather than evaluating the components on an individual basis for each system within the scope of license renewal.

The applicant used its IPA methodology (described in Section 2.0 of Appendix A to the LRA) to determine which systems and components are within the scope of license renewal. As discussed in paragraph 5.3 of the IPA methodology, instrument lines and components in systems within the scope of license renewal are assigned to the scope of the instrument line commodity evaluation (ILCE) during the pre-evaluation process. Because instrument lines are subject to common environments, are made from similar materials, and perform the same passive intended function regardless of the system to which they are assigned, the applicant's IPA process identifies such instrument lines during the pre-evaluation process and excludes them from the AMR of the parent system and assigns them to the ILCE. Since some small-bore piping and tubing do not have unique equipment identification numbers in the site equipment database, the pre-evaluation process also identifies the root valves and all components within the isolable instrument lines as a means to identify commodities that are in scope for the ILCE. In systems in which no root valves are associated with instrument lines, a separate evaluation is needed to determine whether the instrument line should be included with the ILCE or evaluated separately along with the system components.

The applicant identified 22 systems containing instrument lines within the scope of the Instrument Lines Commodity Evaluation in Table 6.4-1 of Appendix A to the LRA. The applicant noted that some instrument line components may be scoped along with their respective systems: for example, instrument line valves and instruments associated with the nuclear steam supply sampling system are evaluated in Section 5.13 of Appendix A to the LRA. The system's small-bore piping and tubing, however, is included in the ILCE and is evaluated in Section 6.4 of Appendix A to the LRA. Assignments for specific instrument line components can be found in each system's LRA scoping section.

The applicant identified maintaining the system pressure boundary as a passive intended function for all instrument line components. In accordance with the LRA, instrument lines that maintain pressure boundaries in the RCS, maintain radiological boundaries to prevent releases that could result in potential offsite exposure comparable to the guidelines in 10 CFR 50.34(a)(1) or 10 CFR Part 100, or maintain safety-related system boundaries to limit system leakage are within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (2). The applicant did not identify any intended function in 10 CFR 54.4(a)(3), other than maintenance of the system pressure boundary.

Instrument types identified in 10 CFR 54.21(a)(1)(i) (i.e., pressure transmitters, pressure indicators, and water level indicators) have active components and are not subject to an AMR. Although these instrument types serve a pressure boundary function, the staff reviewed and accepted, in its final safety evaluation of the applicant's IPA methodology, the position that the functional degradation resulting from the effects of aging on the active function of instrumentation is more readily determinable, and existing programs and requirements are expected to directly detect the effects of aging. The applicant identified other instruments in the scope of the ILCE that have "active" functions and, depending on certain characteristics, can also be excluded from an AMR. To exclude these additional instruments, age-related degradation of the active function must directly correlate to aging effects on the passive pressure boundary, as is the case for instrument types such as pressure transmitters. The applicant reviewed the types of instruments within the scope of the instrument line commodity evaluation and concluded that instruments with one or more of the following characteristics may be excluded from an AMR:

- instruments that sense pressure and have an analog output signal,
- instruments that sense pressure and have a digital output signal, and
- instruments that sense pressure and provide local indication by some moving part.

Instrument types that fall under the criteria stated above include flow transmitters, level transmitters, differential pressure transmitters, level switches, pressure switches, and differential pressure indicators. Removing the instrument types listed above from the ILCE, the applicant concluded that the following remaining instrument line components are subject to an AMR:

- small-bore piping and tubing
- hand valves
- non-pressure-sensing instruments
- supports for instrument lines

2.2.3.35.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the applicant has identified instrument lines within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.35.2.1 Instrument Lines Within the Scope of License Renewal

The staff previously reviewed and accepted the applicant's IPA methodology, which included a methodology to scope instrument lines, and documented staff findings in "Final Safety Evaluation Concerning the Baltimore Gas and Electric Company Report Titled: 'Integrated Plant Assessment Methodology'," dated April 4, 1996. This assessment excluded most instruments connected to instrument lines from an AMR because the pressure-retaining portion of the instrumentation will exhibit functional degradation resulting from the effects of aging. This degradation is expected to be readily determinable and existing programs are expected to directly detect the degradation. To determine whether there is reasonable assurance that the applicant identified the instrument lines that are required to perform the intended functions described in 10 CFR 54.4, the staff performed the following reviews.

Instrument lines with applicable intended functions are located in portions of fluid systems that are within the scope of license renewal as defined by 10 CFR 54.4(a)(1), (2), and (3). The applicant described the method used to identify the systems, structures, and components within the scope of license renewal in Section 2.0 of Appendix A to the LRA. This methodology included an assessment for instrument lines whereby certain instrument lines in portions of fluid systems within the scope of license renewal were evaluated separately in the ILCE from the rest of the system. The applicant identified those systems containing instrument lines within the scope of the ILCE in Table 6.4-1 of Appendix A to the LRA. Using Table 3-1, "CCNPP Systems and Structures," which is found in Section 2.0 of Appendix A to the LRA, and a list of the systems identified by the applicant as being within the scope of license renewal, the staff evaluated the systems listed in Table 6.4-1 to determine whether any fluid systems with instrument lines within the scope of license renewal were omitted from the ILCE. The staff also reviewed the UFSAR for any safety-related functions that were not identified as intended functions in the LRA to verify that all instrument lines having intended functions were included within the scope of license renewal. The staff's review found no omissions of systems with instrument lines within the scope of license renewal from Table 6.4-1 and did not identify any additional intended functions that could result in additional components (instrument line components not identified by the applicant) being within the scope of license renewal and possibly subject to an AMR.

The staff also reviewed component lists for the following systems within the scope of license renewal—auxiliary feedwater system, component cooling system, and spent fuel pool cooling—to determine whether instrument line components within these systems were appropriately accounted for in the scoping process. The staff verified that, for the instrument line components listed in the LRA as being within the scope of license renewal, the components were either identified as being evaluated for an AMR with the process system or were transferred to the ILCE to be evaluated along with similar components. The staff found no instance in which instrument line components within the scope of license renewal were not identified as being within the scope of license renewal in either the process system evaluation or the ILCE.

As described above, the staff has reviewed the information submitted in Section 6.4 of Appendix A to the LRA and other supporting documents. On the basis of that review, the staff finds reasonable assurance that the applicant has appropriately identified the instrument lines that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

2.2.3.35.2.2 Instrument Lines Subject to an Aging Management Review

In Section 6.4.1.1 of Appendix A to the LRA, the applicant defined the category "instrument line" as the components located downstream of the process root valves to the process line. The applicant identified that generally all instrument lines and associated components (i.e., small bore piping, tubing, tubing supports, fittings, valves and connected instruments) for numerous systems (listed in Table 6.4-1) were within the scope of license renewal and included in the Instrument Lines Commodity Evaluation (ILCE). The applicant did note that some valves and connected instruments were addressed in other sections of the LRA. The staff reviewed 100 percent of the information to verify that the applicant identification was correct. As described in detail below, the staff finds no omissions or mistakes in classification by the applicant.

The staff reviewed the instrument lines and associated mechanical and electrical/instrumentation components to verify that the applicant did not miss any component that should be subject to an AMR. The components determined to be electrical/instrumentation components were the connected instruments (e.g., pressure transmitters) which were included in the ILCE because they maintain the pressure boundary function. The mechanical components subject to an AMR, are the small bore piping, tubing, fittings, hand valves, non-pressure-sensing instruments, and supports for instrument line tubing that have a passive intended function of maintaining the system pressure boundary. The connected instruments would normally be classified as subject to an AMR because of their passive intended function. However, the applicant stated that some of these instruments perform an active function also and would thus be excluded from an AMR in accordance with 10 CFR 54.21(a)(1)(i). The applicant also stated that other instruments could also be excluded from an AMR if the age-related degradation of the active function was directly correlated to age-related degradation of the passive pressure boundary function. The staff agrees that the pressure boundary components of active instrumentation may be excluded because the functional degradation resulting from aging effects on active functions is readily determinable from existing programs and requirements (such as surveillance testing and calibration of a pressure transmitter), which are expected to directly detect the effects of aging. The applicant identified the following instruments as not requiring an AMR since these instruments sense pressure and have an analog/digital output or provide a local indication by a moving part:

- flow transmitter
- level transmitter
- differential pressure transmitter
- level switches
- pressure switches
- differential pressure indicators

Non-pressure-sensing instruments such as a level sight glass would be subject to an AMR. The staff agrees that the applicant's determination is consistent with 10 CFR 54.21(a)(1).

The staff reviewed the information presented in Section 6.4 of Appendix A to the LRA and additional information sent by the applicant in response to the staff RAIs. On the basis of this instrument line commodity review, the staff has determined there is reasonable assurance that the applicant has appropriately identified the structure and components subject to an AMR for the instrument lines in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.2.4 Conclusions

The staff has reviewed the information in Sections 3 through 6 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review as set forth above, the staff concludes there is reasonable assurance that the applicant has identified and listed those structures and components subject to an AMR to meet the requirements of 10 CFR 54.21(a)(1).

3 AGING MANAGEMENT REVIEW

Chapter 3 of this SER presents the staff's evaluation of Baltimore Gas and Electric Company's (the applicant's) aging management review (AMR). The applicant provided a proposed supplement to the Final Safety Analysis Report (FSAR) in Appendix B to the license renewal application (LRA), in accordance with 10 CFR 54.21(d). The purpose of the FSAR supplement is to provide an appropriate description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses, so that any future changes to the programs or activities that may affect their effectiveness will be controlled under 10 CFR 50.59.

The content of the FSAR supplement is dependent upon the final bases for the staff's safety evaluation. Therefore, the issue of the information which would be required to be contained in the FSAR supplement was designated as open item 3.0-1 in the March 21, 1999, SER. The staff has now concluded its evaluation, and the information which the staff has determined must appear in the FSAR supplement, or in the applicant's UFSAR is set forth in Appendix E to this SER. A condition will be included in the renewed license requiring that this information be incorporated in the UFSAR at the next update required by 10 CFR Section 50.71(e) after issuance of the renewed license. Therefore, Open Item 3.0-1 is closed.

The applicant has included some components that perform their intended function with moving parts or with a change in configuration or properties in its AMR. Examples are valve internals, damper seats, wire rope on cranes, and fans. In NRC Question No. 11.1 ("Generic Areas"), the staff noted that 10 CFR 54.21(a)(1)(i) excludes valves, other than the valve body, from AMR requirements and that the statements of consideration of the license renewal rule contain the basis for excluding from AMR for license renewal those structures and components that perform their intended functions with moving parts or with a change in configuration or properties. The staff requested that the applicant present the basis for its determination that valve internals are subject to AMR for license renewal. In a letter dated November 12, 1998, the applicant responded to NRC Question No. 11.1 by stating that it is aware of this exclusion but performed this AMR for its own benefit. The staff did not evaluate the applicant's AMR for such components that perform their intended function with moving parts or with a change in configuration or properties because these components are not subject to AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.1 Common Aging Management Programs

3.1.1 Fatigue Monitoring Program and Analysis

3.1.1.1 Introduction

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity because of metal fatigue that results in the initiation and propagation of cracks in the material. The fatigue life of a component is a function of its material, its environment, and the number and magnitude of the applied cyclic loads. The applicant identified fatigue as a potential ARDM for metal components in the plant's nuclear steam supply system (NSSS) and has developed a fatigue monitoring program (FMP) to manage the effects of fatigue for NSSS components. The FMP is discussed in Sections 4.1, 4.2, 4.3, 5.2, 5.9, 5.13, and 5.15 of Appendix A to the LRA. These sections of the LRA address the reactor coolant system (RCS), the reactor pressure vessel (RPV) and control element drive mechanisms (CEDMs), the chemical and volume control system (CVCS), the feedwater system (FWS), the nuclear steam supply sampling system, and the safety injection (SI) system. The staff's evaluation of these systems is in Sections 3.2, 3.3, 3.4, 3.8, and 3.9, respectively, of this SER.

3.1.1.2 Summary of Technical Information in the Application

As described in Sections 4.1, 4.2, 4.3, 5.2, 5.9, 5.13, and 5.15 of Appendix A to the LRA, the FMP monitors and tracks low-cycle fatigue usage for the limiting components of the NSSS and the steam generator (SG) welds between the safe ends and the reducer. The LRA describes two methods used by the FMP to track low-cycle fatigue usage. The first method counts the number of cycles of critical transients for comparison to the analysis of record. The number of cycles of each transient is compared to the number assumed in the analysis of record every 6 months. In the second method, the FMP monitors the actual transient stresses in order to calculate the fatigue usage. In response to NRC Question No. 7.10, the applicant identified the parameters monitored by the FMP and described how those monitored parameters are compared to the fatigue analysis of record. According to the applicant, an American Society of Mechanical Engineers (ASME) NB-3200 fatigue calculation is performed for these locations as the monitored parameters change. The incremental fatigue usage is then added to the existing fatigue usage.

3.1.1.3 Staff Evaluation

Section 2.1.3.3 of Appendix A to the LRA describes the fatigue design of the NSSS. Fatigue was a design consideration for the NSSS components and, consequently, fatigue design is a part of the current licensing basis (CLB) for the plant. The applicant identified the NSSS fatigue analyses as time-limited aging analyses (TLAAs) in accordance with the provisions of 10 CFR 54.3. The staff agrees with the applicant's determination that NSSS fatigue analyses are TLAAs.

The NSSS components evaluated for fatigue in the original design are the RPV and components in the RCS, including the portions of systems attached to the RCS. The RCS components were designed in accordance with ASME Boiler and Pressure Vessel Code Section III and the American National Standards Institute (ANSI) Standard USAS B31.7, "Nuclear Power Piping Code." These codes contain specific criteria for fatigue analysis of Class 1 (Class A) components. The component design specifications and portions of the plant's Updated Final Safety Analysis Report (UFSAR) identify design transients used in the fatigue analysis for various components of the RPV, RCS piping, SG, pressurizer, pressurizer auxiliary spray piping, and pressurizer surge line. The FMP monitors and tracks the number of critical thermal and pressure test transients and also monitors the cycles and fatigue usage for the limiting components of the NSSS.

The specific design criterion pertaining to the fatigue evaluation of Class 1 components involves calculating a quantity called the cumulative usage factor (CUF). The fatigue damage caused by each thermal or pressure transient depends on the magnitude of the stresses in the component caused by the transient. The CUF involves a summation of the fatigue usage resulting from each transient. The design criterion requires that the CUF not exceed 1.0.

Components other than those in the NSSS were generally designed to codes that do not contain the criterion described above for fatigue analysis. The relevant fatigue considerations pertaining to these components are discussed in other sections of this SER. However, as discussed in Section 5.9 of Appendix A to the LRA, fatigue has resulted in cracking in the feedwater (FW) piping to the SGs at other facilities. The applicant's evaluation of cyclic thermal stratification identified the need to manage low-cycle fatigue usage in the section of piping near the SG FW nozzle and, therefore, the applicant included the FW nozzles in the FMP.

The FMP monitors and tracks the fatigue usage for critical components, and the fatigue usage is updated periodically. In Section 4.1 of Appendix A to the LRA, the applicant described different options to manage the effects of low-cycle fatigue at the Calvert Cliffs Nuclear Power Plant (CCNPP). One option considered by the applicant was to reduce the number and severity of thermal transients on the RCS components. The applicant indicated that this is already part of the general practice of the plant operators. Instead, the FMP is used to monitor the fatigue accumulation of the critical components and to manage the effects of low-cycle fatigue.

The applicant indicated that, in order to remain within the design basis, corrective actions would be initiated in advance of reaching the design limit on fatigue usage. The staff, in NRC Question Nos. 4.2.22, 7.13, and 7.20, requested that the applicant describe the criteria used to determine when corrective actions would be initiated. The applicant responded that engineering judgment is used to evaluate the rate of increase in FMP fatigue indicators and that an issue report (IR) would be prepared before reaching the fatigue limit. The applicant's response did not contain sufficient information to enable the staff to conclude that the corrective actions would be timely for managing fatigue effects. However, the applicant stated in a meeting with the staff on February 18, 1999 (NRC meeting summary dated March 19, 1999), that corrective action will be implemented before exceeding the design fatigue limit of the component. The applicant also indicated that the FMP will be expanded if any monitored location requires a corrective action. The staff considers the applicant's clarification, as discussed above, to be an acceptable resolution with regard to the FMP corrective actions.

To manage fatigue, the FMP relies on sampling of critical plant transients for selected NSSS components and the SG FW nozzles. The staff agrees that the sampling of plant transients causing significant fatigue usage for critical components can adequately represent the fatigue usage for the unsampled or remaining locations. In the previous SER (March 21, 1999, CCNPP

SER) several open items regarding the applicant's screening of components to be included in the FMP were identified. These open items regarding the FMP included those identified in Sections 3.2.3.2.2, 3.3.3.2.2, and 3.9.3.2.3 of this SER. Because the applicant has committed to complete the additional evaluations described in these sections of this SER by letter dated July 2, 1999, the staff concludes that the applicant's FMP sampling approach is adequate to manage fatigue of the NSSS components and the SG FW nozzles.

3.1.1.4 Conclusions

The staff considers the FMP, which provides for the continuous monitoring of selected critical components in the NSSS and the SG FW nozzles, an adequate program to monitor the effects of low-cycle fatigue at CCNPP. As a result of the resolution of the open items concerning the FMP, identified in Sections 3.2.3.2.2, 3.3.3.2.2, and 3.9.3.2.3 of this SER, the staff concludes that the FMP will adequately manage low-cycle fatigue in the NSSS and the SG FW nozzles for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.2 Chemistry Program

3.1.2.1 Introduction

Sections 4.1, 5.1, 5.2, 5.3, 5.6, 5.9, 5.11B, 5.12, 5.13, 5.15, 5.16, 5.17, and 5.18 of Appendix A to the LRA describe the chemistry programs used to manage the aging effects caused by the corrosive action of water for systems containing (1) primary water, (2) secondary water, and (3) component cooling and service water. The staff has reviewed each of these sections to determine if the chemistry programs for these systems meet the requirements stated in 10 CFR 54.21(a)(3). By letter dated August 28, 1998, the staff issued RAIs concerning the chemistry program and by letter dated November 12, 1998, the applicant responded. The staff received additional information concerning the applicant's chemistry programs during a meeting held on February 10, 1999 (NRC meeting summary dated March 19, 1999). Section 2.1 of Appendix A to the LRA indicates that there are no TLAAs for the ARDMs caused by water chemistry.

3.1.2.2 Summary of Technical Information in the Application

In the LRA, the applicant established a need for water chemistry programs to minimize the aging effects caused by the following ARDMs: (1) crevice corrosion, (2) erosion/corrosion, (3) galvanic corrosion, (4) general corrosion, (5) pitting, (6) intergranular attack (IGA), (7) stress corrosion cracking (SCC), (8) intergranular stress corrosion cracking (IGSCC), (9) primary water stress corrosion cracking (PWSCC), (10) microbiologically induced corrosion (MIC), (11) selective leaching, and (12) degradation of elastomers. The applicant addressed the ARDMs caused by the corrosive action of water in the following systems:

Primary water

- RCS
- CVCS
- Containment spray system (CSS)
- nuclear steam supply sampling system
- SI system
- spent fuel pool cooling system (SFPCS)

Secondary water

- Auxiliary feedwater system (AFS)
- FWS
- main steam system
- SG system
- extraction steam system
- nitrogen and hydrogen systems

Component cooling and service water

- component cooling (CC) system
- service water (SRW) system

Primary water contains dissolved boric acid for reactivity control in the RCS and lithium hydroxide to control pH. Most of the components in the systems containing primary water are constructed from stainless steel. However, other materials, such as Alloy 600 in the steam generators, are also present. If the water chemistry is not properly controlled, the components exposed to the primary water environment will be damaged by corrosion. The magnitude of this damage will depend on the operating conditions and the material used for the system. Potential ARDMs are (1) crevice corrosion, (2) galvanic corrosion, (3) general corrosion, (4) erosion/corrosion, (5) pitting, (6) MIC, (7) IGA, (8) SCC, (9) IGSCC, and (10) PWSCC.

Secondary water consists of demineralizer water containing chemicals that control pH and oxygen. The components in the systems containing secondary water are constructed mostly from carbon steel and Alloy 600, although other materials, such as stainless and alloy steel, cast iron, brass, bronze, and polymeric materials (elastomers) are also present. These components, when exposed to an uncontrolled secondary water environment, can experience the following ARDMs: (1) crevice corrosion, (2) galvanic corrosion, (3) general corrosion, (4) erosion/corrosion, (5) pitting, (6) MIC, (7) denting, (8) IGA, (9) IGSCC, and (10) degradation of elastomers.

Component cooling water is used to remove heat from various auxiliary systems and, similarly, service water is used to remove heat from the containment cooling units, spent fuel pool, and emergency diesel generator heat exchangers. Service water also acts as an intermediate barrier between various auxiliary systems and saltwater systems. Water in both component cooling water and service water systems consists of demineralizer water containing chemicals that control pH and oxygen. Materials used for the construction of components in these systems are carbon steel, brass, bronze, 90/10 copper-nickel, cast iron, stainless steel, and polymeric materials (elastomers). If not controlled, the interaction between component cooling or service water and these components could result in the following ARDMs: (1) crevice corrosion, (2) erosion/corrosion, (3) general corrosion, (4) pitting, and (5) degradation of elastomers. In addition, any rubber seals present in these systems may degrade.

The applicant will use the following programs to either directly or indirectly contribute to the control of water chemistry:

- CCNPP Technical Procedure CP-222, "Specifications and Surveillance Diesel Generators' Jacket Cooling System," (existing program)
- CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems," (existing program)
- CCNPP Technical Procedure CP-206, "Specifications and Surveillance Component Cooling/service Water," (existing program)
- CCNPP Technical Procedure CP-217, "Specifications and Surveillance Secondary Chemistry," (existing program)
- CCNPP Technical Procedure CP-202, "Specifications and Surveillance Demineralizer Water, Safety Battery Water, and Well Water Systems," (existing program)

The applicant determined that these programs will manage water chemistry control in order to prevent the formation of corrosive environments that can cause damage to the affected components. The prevention of corrosive environments by these water chemistry programs will enable the affected components to perform their intended functions, consistent with the CLB, during the period of extended operation.

3.1.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the water chemistry control programs described in Appendix A to the LRA to ensure that the effects of aging will be adequately managed, consistent with the CLB, for the period of extended operation. The staff focused its evaluation of the water chemistry programs on the program elements rather than on the details of the plant procedures. Specifically, the staff reviewed these programs to determine whether they contain the essential elements needed to provide adequate aging management for each of the components and systems exposed to different water chemistries. In the LRA, the applicant indicated that water chemistry control will be adequately managed by existing water chemistry control programs and that these programs will address each of the relevant ARDMs and meet the requirements of 10 CFR Part 50, Appendix B. The water chemistry programs address water chemistry control in systems containing primary, secondary, component cooling and service water, and EDG jacket cooling water.

The staff notes that the evaluation of aging effects, or ARDMs, identified by the applicant, is discussed by the staff on a system-by-system basis separately in this SER. Also, the applicant's chemistry program is not a standalone program. The applicant relies on many other (aging management programs (AMPs) to manage these ARDMs for these systems. The staff's evaluation of these other programs may be found in the sections of this SER that discuss systems.

The applicant's program for controlling primary water chemistry is based on plant Technical Specifications (TSs), industry standards, and plant vendor recommendations. The chemistry control provided by this program monitors the ingress of such impurities as chloride, fluoride, and sulfate. The program also monitors lithium, oxygen concentrations, and the pH of the coolant. The control of these parameters results in the reduction of corrosion damage to the components exposed to the primary water environment. Specifically, control of these parameters minimizes the IGA, SCC, IGSCC, and PWSCC of the components in the RCS and crevice corrosion and pitting in other systems, especially those containing stagnant fluid. However, not all of the corrosion mechanisms caused by primary water can be controlled by monitoring the primary water chemistry. Instead, some of the corrosion mechanisms are controlled by other programs, such as the erosion/corrosion inspection program for monitoring the erosion/corrosion of the piping in the feedwater system. The staff concludes that the applicant's programs for controlling of primary water chemistry are acceptable because the monitoring of the chemistry parameters provided by these programs will ensure that the pH and the oxygen concentration will be at optimum levels. Furthermore, these programs ensure that the ingress of the impurities that accelerate corrosion will be minimized. Therefore, the applicant's primary water chemistry programs will minimize the effects of ARDMs and in conjunction with the AMPs discussed in other sections of this SER will be able to control the ARDMs in the primary system.

The applicant's program for controlling secondary water chemistry is based on plant Technical Specifications (TSs), Electric Power Research Institute (EPRI) and Institute of Nuclear Power Operations (INPO) secondary water chemistry guidelines, and plant vendor recommendations. The chemistry control provided by this program monitors the ingress of such impurities as chloride, fluoride, and sulfate. The program also monitors the conductivity, the concentration of dissolved oxygen, and the concentration of amine used for pH control. Each of these monitored parameters has action levels that, if exceeded, require chemistry personnel to take appropriate corrective action. The control of these parameters results in the reduction of corrosion damage to the components exposed to the secondary water environment. Secondary water chemistry is monitored in several plant systems such as SG, FWS, condensate storage tanks (CSTs), and condensate demineralizer effluent. In some of these systems, water chemistry is monitored for several different modes of plant operation. The secondary water chemistry program is responsible for controlling four ARDMs: (1) crevice corrosion, (2) general corrosion, (3) pitting, and (4) denting and stress corrosion cracking of SG tubes. These four ARDMs occur mostly in components made from carbon steel or Inconel and exposed to secondary water that has a low pH and a high impurity level. Also, erosion/corrosion is an ARDM that can cause significant damage to the secondary water systems made from both carbon steel and from other materials with the exception of stainless steel. The following secondary water systems discussed in Appendix A to the LRA contain components that are prone to erosion/corrosion: (1) FWS, (2) AFS, and (3) SG system. To prevent erosion/corrosion from causing significant damage to the components in these systems, oxygen content and pH have to be strictly maintained within specified limits. These provisions are included in the applicant's secondary water chemistry program. The staff concludes that the applicant's program for controlling secondary water chemistry is acceptable because the monitoring of the chemistry parameters provided by this program will ensure that the pH and the oxygen concentration will be at optimum levels. Furthermore, this program ensures that the ingress of the impurities that accelerate corrosion will be minimized. Therefore, the applicant's secondary water chemistry program will be able to control the ARDMs in the secondary system.

The applicant's program for controlling water chemistry in the component cooling and service water systems specifies a value for the pH in addition to concentrations of (1) hydrazine, (2) dissolved oxygen, (3) chlorides, (4) copper, and (5) iron. Each of these parameters has an associated target value, and hydrazine and pH have action levels that, if exceeded, specify actions to be taken by plant personnel. In addition, component cooling water is monitored for gamma and tritium activities to determine if any radioactive material has leaked into these systems. This monitoring activity is part of the plant's technical procedure CP-224, "Monitoring Radioactivity in Systems Normally Uncontaminated." Successful implementation of the program for controlling water chemistry in the component cooling and service water systems ensures that the following ARDMs do not cause significant damage to the component cooling and service water systems: (1) crevice corrosion, (2) general corrosion, (3) pitting, and (4) selective leaching. The staff concludes that the applicant's program for controlling component cooling and service water is acceptable because the monitoring of the chemistry parameters provided by this program will ensure that the pH and oxygen concentrations will be at optimum levels. Furthermore, this program ensures that the ingress of impurities that accelerate corrosion will be minimized. Therefore, the applicant's component cooling and service water systems chemistry program will minimize the effects of the ARDM and in conjunction with the AMPs discussed in other sections of this SER will be able to control the ARDMs in these systems.

3.1.2.4 Conclusions

The staff has reviewed the information in Sections 4.1, 5.1, 5.2, 5.3, 5.6, 5.9, 5.11B, 5.12, 5.13, 5.15, 5.16, 5.17, and 5.18 of Appendix A to the LRA that addresses water chemistry in addition to the applicant's responses to the staff RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the plant chemistry program will minimize the potential for the plausible aging degradation mechanisms listed in Section 3.1.2.2 of this SER and , in conjunction with other ARDMs assessed in this evaluation, the aging effects caused by the corrosive action of the chemical environments in CCNPP systems will be adequately managed so that these systems will perform their intended functions in accordance with the CLB during the period of extended operation. However, the staff notes that the water chemistry program is only part of the larger age related degradation management program and will not, by itself, provide this assurance.

3.1.3 Structure and System Walkdowns

3.1.3.1 Introduction

In Appendix A to the LRA, the applicant identified the structure and system walkdown procedure MN-1-319 (formerly plant engineering guideline PEG-7) as one of its AMPs. As described in the LRA, this procedure is used for the following 14 structures and systems:

- component supports (Section 3.1)
- primary containment structure (Section 3.3A)
- turbine building structure (Section 3.3B)
- intake structure (IS) (Section 3.3C)
- miscellaneous tank and valve enclosures (Section 3.3D)
- auxiliary building and safety-related diesel generator building structures (Section 3.3E)
- auxiliary feedwater system (Section 5.1)
- diesel fuel oil system (Section 5.7)
- fire protection (Section 5.10)
- auxiliary building heating and ventilation system (Section 5.11A)
- primary containment heating and ventilation system (Section 5.11B)
- control room and diesel generator buildings' heating, ventilating and air conditioning systems (Section 5.11C)
- safety injection system (Section 5.15)
- instrument lines (Section 6.4).

The purpose of this procedure is to provide direction for performing structure and system walkdowns and for reporting and documenting the results. According to the applicant, the structure and system walkdowns procedure meets the requirements for evaluating structure and system material conditions in accordance with the maintenance rule at CCNPP.

3.1.3.2 Summary of Technical Information in the Application

As described in Appendix A to the LRA and at a presentation by the applicant on June 26, 1998, the main objective of structure and system walkdowns procedure MN-1-319 is to assess the condition of the plant's structures, systems, and components (SSCs) so that any abnormal or degraded condition will be identified and documented, and corrective actions will be taken before the condition proceeds to failure of the SSCs to perform their intended functions. On the basis of the documented walkdown results, corrective actions are to be taken in accordance with QL-2, "Corrective Action Program." This corrective action program is required by 10 CFR Part 50, Appendix B and, at CCNPP, all SSCs (safety-related and non-safety-related) are covered. According to the applicant, the structure and system walkdowns procedure enhances the familiarity of responsible personnel with their assigned structures and systems, and provides extended attention to plant material condition beyond that afforded by operations and maintenance personnel alone. As described at a presentation by the applicant on June 26, 1998, Procedure MN-1-319 will be improved through incorporation of significant additional guidance on specific activities to be included in the scope of structure walkdowns. In addition, this procedure will also be modified to (1) cover some specific structural walkdowns (such as field-erected storage tanks and tank penetrations), (2) provide additional visual inspection criteria specific for detecting leakage near tank penetrations, and (3) add guidance regarding approval authority for significant departures from the specified walkdown scope and schedule.

Walkdowns will be conducted for a variety of reasons: (1) maintenance rule material condition assessments, (2) system readiness review, (3) startup review, (4) system engineering familiarization, (5) pre-outage review, (6) job-specific walkdowns, and (7) periodic walkdowns. The objectives of the structure or system walkdowns are (1) assessing functionality, (2) reporting any SSC stress or abuse (such as thermal insulation damage, bent or broken hangers, excessive vibrations, and unusual noises), (3) reporting any safety/fire hazards (such as broken doors or hardware, inappropriate breaches of fire or flood barriers, or missing equipment guards), (4) assessing the general housekeeping condition (such as debris, condition of painted surfaces, unreadable or missing labels and signs, and lighting), (5) reporting any conditions adverse to quality, (6) reporting unauthorized temporary alterations, and (7) reporting any structural degradation.

The results of a structure or system walkdown are documented by using the appropriate checklist or inspection form. There are separate structure walkdown reports for the containment structure; concrete structures other than containment; masonry walls; intake structure; buried piping, pipe supports, and equipment anchorages; steel structures and connections; water storage tanks; dams, embankments, retaining walls, and canals; and large equipment supports and anchorages and seismic gaps (those features that allow for sway and movement during seismic events). The inspection forms for system walkdowns are either a mechanical system or an electrical system walkdown report. In addition, procedure MN-1-319 uses a walkdown report continuation sheet, pipe support inspection guidelines, and a refueling equipment walkdown report.

Some of the ARDMs that are to be detected and managed under this procedure are (1) corrosion of steel components; (2) crevice corrosion, general corrosion, and pitting of systems carrying primary, secondary, component cooling and service water, and untreated water; (3) elastomer degradation, MIC, and wear of the flexible collars of ducting systems and components; (4) aging effects due to rotating/reciprocating loading from equipment; (5) aging effects due to hydraulic vibration loading or water hammer for supporting frames; and (6) aging effects due to thermal expansion of piping/components. In addition, as explained by the applicant during a meeting on June 26, 1998 (NRC meeting summary dated November 13, 1998), this procedure will also be used for detecting and managing the aging effects of reinforced-concrete structures such as spalling and cracking.

The LRA states that a performance assessment will be performed on each structure and system at least once every 6 years. In response to the staff's RAI, the applicant stated that structure and system walkdowns will be performed every refueling outage and are scheduled to ensure that a walkdown will be performed on every structure and system at least every third refueling outage. Hence, a performance assessment will be performed on each structure and system at least once every 6 years. Structure and system walkdowns may also be performed as required for such reasons as material condition assessment; system reviews before, during, and after outages; start-up reviews; and as required for plant modifications.

Following completion of the walkdowns, the system engineer is to make an evaluation of the structure or system status from a performance basis. If structure or system degradation is noted during the walkdown, the system engineer will contact the principal engineer—Maintenance Component Engineering Unit (PE-MCEU) to determine whether the structure or system is capable of performing its intended function. The IR process will then be used to document and resolve the noted degradation.

3.1.3.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff has reviewed the application of the structure and system walkdown procedure (MN-1-319) to the SSCs that require an AMR. The areas covered by this walkdown procedure include SSCs described in Sections 3.1, 3.3A, 3.3B, 3.3C, 3.3D, 3.3E, 5.1, 5.7, 5.10, 5.11A, 5.11B, 5.11C, 5.15, and 6.4 of Appendix A to the LRA. In the LRA, as stated below, the applicant demonstrated that the effects of aging, through the implementation of this procedure, will be adequately identified and managed so that the intended function of the SSCs will be maintained, consistent with the CLB, for the period of extended operation.

The staff has evaluated procedure MN-1-319 against the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience. The applicant indicated that the analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective actions program is discussed separately in Section 3.1.5 of this SER. For the reasons stated in Section 3.1.5, the staff finds that the applicant's AMPs for license renewal satisfy Element 7 (corrective actions), Element 8 (confirmation process), and Element 9 (administrative controls). As set forth below, the staff finds that the structure and systems walkdown procedure (MN-1-319) satisfies each of the other seven elements.

The staff finds the scope (Element 1) of procedure MN-1-319 acceptable because it includes comprehensive, regular, periodic walkdowns of all SSCs within the scope of license renewal. These SSCs are listed in Section 3.1.3.1 of this SER. The staff finds the preventive actions (Element 2) required by the structure and system walkdown procedure acceptable since any observed system or structure degradation, as well as conditions leading to degradation, will result in an IR. As such, any degraded condition will be identified, documented, and its cause determined. Furthermore, corrective action will be initiated before the degradation proceeds to failure of the SSC to perform its intended function. The staff finds that the parameters monitored (Element 3) (e.g., degradation of coatings, thermal insulation damage, distress to equipment anchorage, excessive vibrations) acceptable because they are conditions directly related to the degradation of the system or structure or, in case of a poor housekeeping condition, such as degraded coatings, a condition that renders a component more susceptible to degradation. The structure and system walkdown procedure provides for the detection of aging effects (Element 4) through visual inspection. Under this procedure responsible personnel perform periodic walkdowns of their assigned system or structure and, if necessary, initiate corrective action. The staff finds visual inspections to be an acceptable method for detecting aging effects of the 14 structures and systems listed in Section 3.1.3.1 of this SER. The staff finds that operating experience (Element 10) has been incorporated into procedure MN-1-319 since the results of initial walkdowns will be used for future walkdowns (e.g., the assessment of system or structure degradation is based on previous walkdowns).

In Appendix A to the LRA, the applicant stated that under this program responsible personnel perform periodic walkdowns of their assigned structures, systems and components, report walkdown results, and initiate corrective actions. Appendix A to the LRA states that a performance assessment will be performed on each structure and system at least once every 6 years, and structure and system walkdowns may also be performed, as required, for reasons such as (1) material condition assessments; (2) system reviews before, during, and after outages; (3) startup reviews; and (4) as required for plant modifications. In an RAI sent to the applicant on September 7, 1998, the staff asked the applicant to demonstrate that procedure

MN-1-319 satisfies the monitoring and trending activities. In its response of November 19, 1998, the applicant stated that the assessment of structure or system degradation is based on the findings of previous walkdowns. Specifically, the findings of the current and previous walkdowns are compared to determine if the degradation is static or active. Active degradation would result in an initiation of the IR corrective action process. An example of active degradation provided by the applicant is a safety-related pump pedestal that has extensive cracking and the pump mounting bolts are pulling loose so that the pump is vibrating abnormally. Static degradation of a structure or system is any degradation that is arrested or proceeding at a rate that will not affect the functional capability of the SSC. The staff finds that a complete comparison of current and previous walkdown findings for structures and systems in addition to a review of all pertinent system documentation (i.e., the latest "system report card," temporary modifications, and modifications in progress) satisfies monitoring and trending of Element 5.

Appendix A to the LRA states that procedure MN-1-319 is a followup procedure and provides guidance for identification of specific types of degradations and conditions such as degraded paints, corrosion of steel components, concrete and anchor bolt degradation, and leakage of fluids. This procedure is also to be used for identifying the conditions of SSCs (including supports) that could allow for the progression of ARDMs, such as standing water and accumulated moisture. The staff requested by letter dated September 7, 1998, that the applicant provide the acceptance criteria to be used for procedure MN-1-319. The applicant's response dated November 19, 1998, is that the engineering judgment of the system engineer and the PE-MCEU will be relied upon to determine if the performance of the system or structure is acceptable and to determine if any observed degradation is static or dynamic. In addition, the performance of the system or structure and any observed degradation will be compared with "acceptable limits contained in industry standards, industry codes, or design/licensee-basis documents" (MN-1-319).

The staff finds that the use of industry standards and codes or design/license-basis documents, if available, in conjunction with the judgement, based on common engineering practices, of the system engineer and other responsible personnel is an acceptable method for evaluating the acceptability of the system or structure.

In addition to the elements discussed above, the staff, in a letter dated September 7, 1998, requested that the applicant discuss the use of procedure MN-1-319 for identifying and managing the aging effects of reinforced-concrete structures. The applicant, in its response dated November 19, 1998, stated that the omission of aging mechanisms for concrete walls, covered by the structure walkdown reports used by procedure MN-1-319, was an oversight. As such, the structure walkdown reports will be modified to detect the aging effects of reinforced-concrete structures. This was identified as Confirmatory Item 3.1.3.3-1 in the previous SER.

In letters dated November 19, 1998 and July 2, 1999, the applicant committed to revise procedure MN-1-319 (Attachment 4, "Structure Monitoring Walkdown; Concrete Structures Other Than Containment") to clearly provide for the inspection of reinforced-concrete walls within concrete structures other than the containment. The inspection of containment walls will be covered by Attachment 3 to procedure MN-1-319. On this basis, the staff concludes that Confirmatory Item 3.1.3.3-1 is closed.

3.1.3.4 Conclusions

The staff considers structure and system walkdown procedure MN-1-319 to be an adequate procedure for detecting and managing aging effects, and initiating corrective actions if needed. Furthermore, the staff finds that procedure MN-1-319 will be able to adequately assess the condition of plant SSCs for the period of extended operation in accordance with the requirements of 10 CFR 54.21(a)(3).

3.1.4 Boric Acid Corrosion Inspection Program

3.1.4.1 Introduction

In its LRA, the applicant described the BACI program. This program manages general corrosion of carbon and alloy steels exposed to concentrated boric acid. The applicant credited the BACI program in the following sections of Appendix A to the LRA: Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes"; Section 4.1, "Reactor Coolant System"; Section 4.2, "Reactor Pressure Vessel and Control Element Drive Mechanisms/Electrical"; Section 5.2 "Chemical and Volume Control System"; Section 5.5, "Containment Isolation Group"; Section 5.6, "Containment Spray System"; Section 5.10, "Fire Protection"; Section 5.13, "Nuclear Steam Supply System (NSSS) Sampling System"; Section 5.15, "Safety Injection System"; and Section 5.18, "Spent Fuel Pool Cooling System." The applicant also credited the BACI program with managing, in part, general corrosion of carbon steel components from exposure to moisture and oxygen in Section 3.2, as well as various forms of SCC of Alloy 600 components and erosion, wear and SCC of carbon and alloy steel components in Sections 4.1 and 4.2. The staff reviewed the applicant's description of the program to determine whether the applicant submitted adequate information to meet the requirements stated in 10 CFR 54.21(a)(3) for managing aging effects for license renewal.

3.1.4.2 Summary of Technical Information in the Application

The concentrations of boric acid in the borated water systems of a nuclear power plant will not corrode carbon and alloy steels. However, borated water that has leaked outside of the system may become much more concentrated as a result of water evaporation. When exposed to concentrated boric acid, carbon and alloy steels suffer general corrosion. Corrosion rates may be significant and thus, if left unmanaged for an extended period of time, the resultant material loss may render a component unable to perform its intended function under CLB design loading conditions. The potential for general corrosion from exposure to concentrated boric acid cannot be eliminated; however, actions can be taken to detect and mitigate this aging effect before there is a loss of intended function. The applicant credited the BACI program with discovery and mitigation of the aging effects (loss of material) associated with general corrosion of carbon and alloy steel from exposure to concentrated boric acid. The program consists of regular, periodic walkdowns during which plant personnel look for leaks by visually inspecting borated systems. Timely discovery of leaks and subsequent corrective action (e.g., repair of the borated water leak path and removal of the concentrated boric acid residue from the surfaces of affected components) mitigates the effects of concentrated boric acid corrosion. The program also requires engineering evaluation of the affected component(s) for an assessment of any damage.

The BACI program controls the scope of the inspection and the inspection technique. During each refueling outage, plant personnel perform visual inspections to identify and quantify any leakage found at specific locations inside the containment and in the auxiliary building as soon as possible after attaining hot standby condition. The specific locations are carbon steel bolting on Class 1 valves, valves in systems containing borated water (which could leak onto Class 1 carbon steel components), and components where borated water leakage has been previously identified. The program also provides the responsibilities for initiating engineering evaluations and the necessary corrective actions upon discovery of leaks. When personnel discover leakage during the inspection, they prepare an IR in accordance with plant procedures to document and resolve the deficiency. Corrective actions address the removal of concentrated boric acid residue and the subsequent inspection of the affected component for general corrosion. If personnel identify general corrosion on a component, the IR provides for an engineering evaluation of the component for continued service. The IR also addresses corrective actions to prevent recurrence (i.e., identify and correct the cause of the leak). Finally, the BACI program requires that a second inspection of the leaking component(s) be performed before plant startup (at normal operating pressure and temperature) to ensure corrective actions had been taken and were effective.

The BACI program incorporates ASME Code requirements, as appropriate. For example, the applicant performs its VT-2 visual inspections in accordance with ASME Code Section XI, IWA-2212 and its VT-1 examinations in accordance with ASME Code Section XI, IWA-2211. The VT-2 visual inspections must include the accessible external exposed surfaces of pressure-retaining, noninsulated components; floor areas or equipment surfaces located underneath uninsulated components; vertical surfaces of insulation at the lowest elevation at which leakage may be detected and horizontal surfaces at each insulation joint for insulated components; floor areas and equipment surfaces beneath components and other areas in which 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. The BACI program requires, at a minimum, qualified Level II inspectors for the evaluation of the damage caused by borated water leaks.

In Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes," the applicant identified general corrosion as a plausible ARDM affecting the carbon steel RV cooling shroud structural support members. The support members are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water from the nearby RV head penetrations. The RV head penetrations are within the scope of the BACI program. The applicant plans to modify the BACI program to include specific examination of the RV cooling shroud structural support members at the bolted connection to the RV head.

In Section 4.1, "Reactor Coolant System," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of carbon and alloy steel components in the RCS. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in the RCS or nearby systems that also contain borated water. The RCS is within the scope of the BACI program.

In Section 4.2, "Reactor Pressure Vessel and Control Element Drive Mechanisms/Electrical," the applicant identified general corrosion as a plausible ARDM affecting carbon steel RPV components. The subject components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through mechanical joints in the RPV. The RPV is within the scope of the BACI program.

In Section 5.2, "Chemical and Volume Control System," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of alloy or carbon steel CVCS components. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in the CVCS piping system or nearby systems that also contain borated water. The CVCS is within the scope of the BACI program.

In Section 5.5, "Containment Isolation Group," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of carbon and low alloy steel bolting of the motor-operated valves (MOVs) in the containment's normal sump drain lines. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in the containment isolation (CI) group piping system or nearby systems that also contain borated water. The MOVs in the containment normal sump drain lines are within the scope of the BACI program.

In Section 5.6, "Containment Spray System," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of various carbon and alloy steel components of the CSS. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in the CSS or nearby systems that also contain borated water. The CSS is within the scope of the BACI program.

Because both the RCS and the CVCS play a role in fire protection (Section 5.10), the applicant cited the BACI program as part of its aging management program for fire protection. The BACI program as it relates to the RCS (Section 4.1) and CVCS (Section 5.2) is discussed above.

In Section 5.13, "NSSS sampling system," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of various carbon and alloy steel components of the NSSS sampling system. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in certain portions of the NSSS sampling system or nearby systems that also contain borated water. The NSSS sampling system components containing borated water are within the scope of the BACI program.

In Section 5.15, "Safety Injection System," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of various carbon and alloy steel components of the SI system. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through the mechanical joints in the SI system or nearby systems that also contain borated water. The SI system is within the scope of the BACI program.

In Section 5.18, "Spent Fuel Pool Cooling System," the applicant identified general corrosion as a plausible ARDM affecting the external surfaces of various carbon and alloy steel components of the SFPCS. The external surfaces of these components are not normally exposed to concentrated boric acid, but they may be exposed as a result of leakage and subsequent concentration of borated water through mechanical joints in the SFPCS or nearby systems that also contain borated water. The SFPCS is within the scope of the BACI program.

In addition to managing general corrosion of carbon and alloy steels from exposure to concentrated boric acid, the applicant cited the BACI program to manage, in part, other ARDMs in Section 3.2, Section 4.1, and Section 4.2.

In Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes," the applicant identified general corrosion as a plausible ARDM affecting the carbon steel RV cooling shroud structural support members. If the painted surfaces of the support members crack, spall, or otherwise expose the carbon steel surfaces of the support members, the support members may experience general corrosion from exposure to moisture and oxygen. Additionally, the applicant discussed how some internal portions of the RV cooling shroud can harbor pockets of liquid that may be inaccessible for visual inspection without removing interference. Carbon steel located in these areas may be subject to more severe local environments. To manage this aging effect for the RV cooling shroud structural support members, the applicant plans to modify the scope of the BACI program to include inspection of all the RV cooling shroud structural support members to inspect the painted surfaces for evidence of general corrosion due to breakdown of the paint and subsequent exposure to moisture and oxygen.

In Section 4.1, "Reactor Coolant System," the applicant identified wear, erosion, and SCC as plausible ARDMs affecting various RCS components. The applicant cited the BACI program to manage, in part, the aging effects associated with these ARDMs. For the components subject to wear (except for the reactor coolant pump case and pump cover), erosion/corrosion, and some forms of SCC, the applicant credited its Section XI inservice inspection program (evaluated in Section 3.2 of this SER) for the detection of the aging effects associated with these ARDMs. If the wear, erosion/corrosion, or SCC resulted in borated water leakage, the applicant credited the BACI program for the mitigation of the aging effects associated with the borated water leakage as well as follow-up corrective action. For the reactor coolant pump case and cover and for components subject to PWSCC (i.e., Alloy 600 nozzles), the applicant credited the BACI program for both detection and mitigation of the aging effects associated with these ARDMs. Any deterioration in the pressure boundary of these components will be discovered through detection of borated water leakage. The applicant placed the reactor coolant pump and cover as well as all Alloy 600 nozzles within the scope of the BACI program.

In Section 4.2, "Reactor Pressure Vessel and Control Element Drive Mechanisms/Electrical," the applicant identified general corrosion, wear, and SCC as plausible ARDMs affecting various RPV components. For various carbon and alloy steel RPV components, general corrosion occurs upon exposure to moisture and oxygen. The CEDM and reactor vessel level monitoring system (RVLMS) vent balls may suffer wear. The RPV anchor bolts are susceptible to SCC. The applicant cited the BACI program to manage, in part, the aging effects associated with these ARDMs. For the components subject to general corrosion, the applicant credited its inservice inspection program and its maintenance procedures (evaluated in Section 3.2 of this SER) for the detection of the aging effects associated with this ARDM. If the general corrosion resulted in borated water leakage, the applicant credited the BACI program for the mitigation of the aging effects associated with borated water leakage as well as follow-up corrective action. For the components subject to wear, the applicant managed this ARDM through the BACI program. The BACI program included inspection around the CEDM and RVLMS vent area; detection of borated water leakage would indicate that the CEDM and RVLMS vent balls were experiencing wear and would need to be replaced. For the RPV anchor bolts subject to SCC, the applicant credited its inservice inspection program for the detection of the aging effects associated with this ARDM. If the SCC resulted in borated water leakage, the applicant credited the BACI program for the mitigation of the aging effects associated with the leakage as well as with follow-up corrective action.

The applicant has modified the BACI program to account for operating experience. 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. In addition, both units experienced borated water leakage through the in-core instrument flange connections that resulted in higher-than-anticipated corrosion rates. The applicant described a weakness of the BACI program that existed at the time of these events: it only required specific inspection for leaks at the beginning and end of each outage; it did not address leaks discovered outside of normal inspections. As a corrective action, the applicant revised the BACI program to ensure that all borated water leaks are evaluated by qualified personnel regardless of how and when the leakage was discovered.

3.1.4.3 Staff Evaluation

The staff focused its evaluation of the BACI program on the program elements rather than on the details of the specific plant procedure. The staff evaluated how effectively the BACI program incorporated the following 10 elements (1) program scope, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled corrective action program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is discussed separately in Section 3.1.5 of this SER. The staff finds that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about the boric acid corrosion inspection program discussed in Sections 3.2, 4.1, 4.2, 5.2, 5.5, 5.6, 5.10, 5.13, 5.15, and 5.18 of Appendix A to the LRA regarding the applicant's demonstration that effects of aging caused by various forms of corrosion will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation. By a letter dated April 8, 1998, the applicant submitted its LRA. By a letter dated September 3, 1998, the staff issued an RAI. By a letter dated November 4, 1998, and as further discussed below, the applicant responded, in part, to the staff's RAI.

Program Scope

The staff finds the scope of the BACI program acceptable because it includes comprehensive, regular, periodic walkdowns of all borated systems within the scope of license renewal. The scope of the BACI program also provides for the resolution of any boric acid leakage found outside the specific BACI program walkdowns. In Open Item 3.1.4.3-1 of the previous SER, the staff questioned the applicant's ability to access internal portions of the RV cooling shroud during the normal BACI program walkdowns. In its response dated July 2, 1999, the applicant described the plant activities that occur during a refueling outage relative to the RV shroud. These activities allow for access to the internal portions of the RV cooling shroud for inspection.

On the basis of this clarification, the staff finds acceptable the scope of the BACI program and considers Open Item 3.1.4.3-1 closed.

The applicant plans to modify the BACI program to specify examinations, during each refueling outage, of the RV cooling shroud anchorage to the RV head for evidence of boric acid leakage and all RV cooling shroud structural support members for general corrosion/oxidation. To capture this modification, this item was identified as Confirmatory Item 3.1.4.3-1in the previous SER.

By letter dated July 2, 1999, the applicant committed to modifying by March, 2000, the BACI program to specify examinations, during each refueling outage, of the RV cooling shroud anchorage to the RV head for evidence of borated water leakage and all RV cooling shroud structural support members for general corrosion/oxidation. With this commitment, the staff considers Confirmatory Item 3.1.4.3-1 closed.

Preventive Actions

The staff finds the mitigative actions required by the BACI program acceptable because the removal of concentrated boric acid and the elimination of borated water leakage mitigate corrosion by minimizing the exposure of the susceptible material to the corrosive element. The staff finds also that coatings (i.e., paint) of the RV cooling shroud structural support members mitigate the effects of corrosion by providing a protective layer that prevents moisture and oxygen from contacting the steel. For the other ARDMs managed by the BACI program (e.g., wear, erosion, SCC), there are no mitigative actions in the BACI program. For these ARDMs, the applicant relies on condition monitoring techniques rather than on preventive or mitigative actions. The staff did not identify a need for such actions on the basis of operating experience to date.

Parameters Monitored

The staff finds the parameters monitored (e.g., boric acid residue, borated water leakage, degradation of coatings) acceptable because they are conditions directly related to the degradation of components or, in the case of degraded coatings, a condition that renders a component more susceptible to degradation.

Detection of Aging Effects

The staff finds visual inspections acceptable for detecting boric acid leaks because such conditions (e.g., boric acid crystal buildup, pools of moisture) are easily identified by visual techniques. However, in its September 3, 1998, RAI, the staff requested that the applicant describe how the inspection frequency would detect and correct general corrosion caused by boric acid before there is a loss of the structure's or component's intended function. In its response dated November 4, 1998, the applicant stated that its frequency (at least every refueling outage) is in line with industry guidance presented in Electric Power Research Institute report NP-5985, "Boric Acid Corrosion of Carbon and Low-Alloy Steel Pressure Boundary Components in PWRs." The applicant also stated that the staff reviewed all utilities' responses to Generic Letter (GL) 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants," in NUREG/CR-5576, "Survey of Boric Acid Corrosion of Carbon Steel Components in Nuclear Power Plants," and concluded that all the programs met the intent of GL 88-05. Although this is true, neither the EPRI report, nor the NRC report, nor the applicant in its RAI response explicitly discussed inspection frequency and the basis for acceptability. The applicant did, however, present an explicit basis for the inspection frequency in one section of its application. In Section 4.2, the applicant stated that "[t]he 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." With general corrosion rates as high as 1.7 inch/yr measured in the laboratory (NP-5985), it is possible that, under the worst possible conditions, material loss could be such that a component's intended function would be compromised. The staff identified the same issue (i.e., no explicit basis justifying the adequacy of an inspection frequency of every refueling outage) associated with the other ARDMs managed, in part, by the BACI program, such as wear, erosion/corrosion, and SCC. However, the staff realizes that, as a practical matter, it is not possible to inspect more frequently than each refueling outage, and operating experience to date appears to support the continuation of such a frequency. In addition, the applicant's TSs provide defense in depth with respect to the detection of unidentified leakage in excess of 1 gpm. The staff considers the applicant's TS limits on unidentified leakage an important part of the aging management program in order to (1) detect leakage that develops between refueling outages and (2) ensure that leakage is identified before there is a loss of a component's intended function. With that amplification, the staff concludes that the applicant's inspection frequency for the BACI program is adequate to detect the aging effects caused by the various corrosion mechanisms discussed above before there is a loss of a component's intended function.

Monitoring and Trending

There are no monitoring/trending processes associated with the BACI program, and the staff did not identify a need for any.

Acceptance Criteria

The staff finds the applicant's acceptance criteria acceptable because the applicant indicated that all borated water leaks are evaluated.

Operating Experience

The applicant discussed operating experience and resultant changes made to the BACI program, such as increased scope and enhanced personnel qualifications for evaluations of degradation. The applicant appears to have incorporated operating experience, as appropriate.

3.1.4.4 Conclusions

The BACI program manages the general corrosion of carbon and alloy steels exposed to concentrated boric acid. The staff has reviewed the BACI information in Appendix A to the LRA, as credited in the following sections: Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes"; Section 4.1, "Reactor Coolant System"; Section 4.2, "Reactor Pressure Vessel and Control Element Drive Mechanisms/Electrical"; Section 5.2, "Chemical and Volume Control System"; Section 5.5, "Containment Isolation Group"; Section 5.6, "Containment Spray System"; Section 5.10, "Fire Protection"; Section 5.13, "Nuclear Steam Supply System (NSSS) System Sampling System"; Section 5.15, "Safety Injection System"; and Section 5.18, "Spent Fuel Pool Cooling System," as well as additional information sent by the applicant in response to the staff's RAI. On the basis of the staff's review as stated above, the staff concludes that the applicant has demonstrated that the aging effects associated with the general corrosion of carbon and alloy steels exposed to concentrated boric acid will be adequately managed by the BACI program so that there is reasonable assurance that carbon and alloy steels exposed to concentrated boric acid will perform their intended functions in accordance with the CLB during the period of extended operation.

3.1.5 Corrective Actions Program

3.1.5.1 Introduction

In Section 6.3, "Methods to Manage the Effects of Aging," of Section 2.0 "Integrated Plant Assessment Methodology" of Appendix A to the LRA, the applicant described how aging management methods are chosen and justified for the period of extended operation. The applicant stated that the primary goal of aging management is to manage the effects of aging so that the intended functions are maintained consistent with the CLB and, therefore, each phase of the maintenance strategy considers this goal when determining the adequacy of an existing or proposed program.

3.1.5.2 Summary of Technical Information in the Application

The applicant's maintenance strategy consisted of four phases: (1) discovery, (2) assessment/ analysis, (3) corrective action, and (4) confirmation/documentation. Each of these phases is focused on the goal of managing the effects of aging so that the intended functions of SSCs are maintained consistent with the CLB.

To select the appropriate method for detecting aging effects, the applicant proposed to use a panel of site experts consisting of (1) an engineer with expertise in aging evaluation, (2) a systems engineer, (3) appropriate plant program managers/technical area specialists, and (4) an engineer with expertise in aging management implementation. Each review is to be conducted on a system or commodity basis. The task of the panel is to determine the appropriate methods to manage the effects of aging by considering (1) the likelihood that each

ARDM will occur and (2) how the effects of the ARDM progress. If the panel determines that the ARDM is progressing slowly and the consequences to the system are not significant, then the ARDM and its effects on the system will be monitored. However, an age related degradation inspection (ARDI) and performance monitoring will be implemented if the ARDM has not been previously observed in operating plants, the progression of the ARDM is gradual, or the effects of the ARDM could have a severe impact on the system.

The applicant stated that the site expert panel will also select an appropriate method for discovering aging effects. These methods are (1) existing plant programs, (2) site issue report and corrective action, (3) plant modifications, (4) ARDIs, and (5) industry operating experience. Existing plant programs are usually selected as the preferred method if such programs are able to identify the aging effect. These plant programs may also be modified, if necessary, by (1) adding components to inspection procedures for specific aging effects, (2) adding specific aging effects mitigation procedures, and (3) modifying recordkeeping and trending requirements. In the event that existing plant programs cannot be modified to discover an aging effect, then new programs will be implemented. Site IR and corrective action is the method used when aging effects are observed as a result of work in the vicinity, plant tours by supervisors, maintenance planning walkdowns, fire watches, or personnel safety equipment inspections. Any observed aging effect, whether or not related to the purpose of the specific activity, is documented with an IR. Plant modifications, such as relocation of equipment, change of material to improve resistance, or change in equipment operation is the appropriate method when industry experience indicates that the ARDM is occurring, plant programs cannot adequately discover the effects of aging, and the progression is rapid. ARDI is the appropriate method to provide additional assurance that significant degradation is not occurring or that the rate is sufficiently slow, and to verify the effectiveness of an ARDM mitigation program. The inspections are to be performed on a representative sample and, where possible, a sample biased to focus on the most important components. Monitoring industry operating experience is part of the site IR and corrective action process to determine if action is necessary at the plant.

The applicant stated that the assessment/analysis, corrective action, and confirmation/ documentation 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 requiring corrective action is documented with an IR. This results in an evaluation of the degraded condition for personnel, nuclear safety, and operability concerns. Furthermore, the responsible organization is assigned the task of resolving the IR and the IR remains open until appropriate corrective actions are completed and documented. Finally, for significant events, a root cause analysis and event investigation are conducted to prevent reoccurrence.

3.1.5.3 Staff Evaluation

The staff focused its evaluation of the applicant's AMPs on the program elements rather than on the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

In Section 6.3, "Methods to Manage the Effects of Aging," of Section 2.0 "Integrated Plant Assessment Methodology," of Appendix A to the LRA, the applicant described how the aging management methods are chosen and justified for the period of extended operations. The applicant identified four phases for an aging maintenance management strategy: discovery, assessment/analysis, corrective action, and confirmation/documentation. In Section 6.3.4, "Implementing the Assessment/Analysis, Corrective Action, and Confirmation/Documentation Phases of the Maintenance Strategy," the applicant indicated that these last three phases of the maintenance strategy are required by the CLB and are provided by the site IR and corrective action processes, which are conducted in accordance with the provisions of QL-2," Corrective Actions Program." The application also stated that processes and activities encompassed by QL-2 are conducted pursuant to the requirements of Appendix B to 10 CFR Part 50 and cover all structures and components subject to an AMR. Because this program is subject to the requirements of 10 CFR Part 50, Appendix B, the staff finds this program approach acceptable. However, the staff concluded that an appropriate description should be provided in a supplement to the FSAR and/or in the applicant's "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant" (which is controlled by 10 CFR 50.54(a)) to indicate that the applicant's Appendix B program also applies to non-safety-related structures and components that are subject to an AMR for license renewal, so that any changes to the programs or activities that may affect crediting for aging management can be appropriately controlled. This was identified as Confirmatory Item 3.1.5.3-1.

By letter dated September 28, 1999, the applicant provided a response to Confirmatory Item 3.1.5.3-1. As stated in this response, the applicant committed to include in the FSAR and/or in their Quality Assurance Program description, an explicit commitment that those Appendix B Quality Assurance Program elements specifically related to "corrective actions," "confirmation processes," and "administrative controls" apply to non-safety-related systems, structures, and components that are subject to an AMR for license renewal, such that any changes to the programs or activities that may affect crediting for aging management can be appropriately controlled. Based on this revised response, the staff has determined that the corrective actions program is adequate to manage the effects of aging so that the intended system, structure, and component functions are maintained consistent with the CLB for the period of extended operation. Confirmatory Item 3.1.5.3-1 is closed.

3.1.5.4 Conclusions

The staff concludes that in light of the applicant's commitment to apply the corrective actions, confirmation processes, and administrative controls to non-safety-related structures and components subject to an AMR adequate information exists to show that the corrective actions program will be sufficient to manage the effects of aging so that the intended system, structure, and component functions are maintained consistent with the CLB for the period of extended operation.

3.1.6 Age Related Degradation Inspection (ARDI) Program

3.1.6.1 Introduction

In its LRA, the applicant described a compilation of one-time inspections called "age related degradation inspections" (ARDIs). On the basis of an assessment of materials of fabrication, operating conditions, and operating experience, the applicant believed that many ARDMs are probably not occurring or that even if they are occurring, they do not and will not affect a component's intended function. To verify this conclusion, the applicant will rely on ARDIs to either (1) verify that an ARDM need not be managed for the period of extended operation or (2) verify the effectiveness of a separate preventive-type or mitigative-type aging management program.

The applicant used ARDIs in the following sections of Appendix A to the LRA: Section 4.1, "Reactor Coolant System"; Section 4.3, "Reactor Vessels Internals System"; Section 5.1, "Auxiliary Feedwater System"; Section 5.2, "Chemical and Volume Control System"; Section 5.3, "Component Cooling System"; Section 5.4, "Compressed Air System"; Section 5.5, "Containment Isolation Group"; Section 5.6, "Containment Spray System"; Section 5.8, "Emergency Diesel Generator System"; Section 5.9, "Feedwater"; Section 5.10, "Fire Protection"; Section 5.11A, "Auxiliary Building Heating and Ventilation System"; Section 5.11B, "Primary Containment Heating and Ventilation System"; Section 5.11C, "Control Room and Diesel Generator Buildings' Heating and Ventilation Systems"; Section 5.12, "Main Steam, Steam Generator Blowdown, Extraction Steam, and Nitrogen and Hydrogen Systems"; Section 5.13, "NSSS Sampling System"; Section 5.14, "Radiation Monitoring System"; Section 5.15, "Safety Injection System"; Section 5.16, "Saltwater System"; Section 5.17, "Service Water System"; and Section 5.18, "Spent Fuel Pool Cooling System." ARDIs as described in LRA Sections 3.1, "Component Supports"; 6.1,"Cables"; and 6.4, "Instrument Lines," are discussed in Sections 3.11, 3.12, and 3.9, respectively, of this SER.

3.1.6.2 Summary of Technical Information in the Application

In the LRA, the applicant stated that the scope of an ARDI would include a representative sample of the system population. Where practical and prudent, the applicant would also bias that representative sample to focus on bounding or leading components. The applicant presented examples of how such biasing would be performed through an understanding of the ARDM followed by an identification of the most likely places for occurrences in the system (e.g., time in service, severity of conditions, and lowest design margin). The applicant also provided criteria for expanding the sample inspected should unacceptable results be obtained from the ARDIs. The applicant plans to use a variety of nondestructive techniques, including visual, ultrasonic, and surface techniques. The applicant would perform these inspections using qualified procedures and personnel that are consistent with the ASME Code, 10 CFR Part 50 (Appendix B), and ASTM standards, as applicable. The applicant stated in the LRA that all relevant indications would be evaluated under the applicant's existing corrective action program.

For nearly every system in its LRA, the applicant reported a need for an ARDI to either (1) confirm that an ARDM need not be managed for the period of extended operation or (2) confirm the effectiveness of an aging management program. The ARDI purpose for each system is described briefly.

For the reactor vessel internals (RVIs) system (Section 4.3), the applicant related the need for an ARDI to verify that neither stress relaxation nor SCC need to be managed for the period of extended operation. The applicant plans to first perform an analysis to demonstrate that stress relaxation and SCC is not taking place or, if taking place, would have no effect on a component's intended function (this analysis is discussed in Section 3.2 of this SER). If the applicant cannot definitively prove from its analysis that neither stress relaxation nor SCC are being managed, the applicant would use an ARDI to examine the affected components. The applicant stated that the location of some of the components may require the use of remote inspection techniques.

For the AFW system (Section 5.1), the applicant plans to perform an ARDI at the locations in the AFW system most susceptible to cavitation erosion to verify that this ARDM need not be managed for the period of extended operation. The applicant identified various forms of corrosion of the internal components of the AFW system as plausible ARDMs that are managed primarily through its chemistry control program (the chemistry program is discussed in Section 3.1.2 of this SER). To verify the effectiveness of its chemistry program, the applicant plans an ARDI of the most susceptible locations (e.g., those areas with low-flow or stagnant conditions, those areas with crevice-like conditions, and those areas without hydrogen overpressure protection).

The applicant identified various forms of corrosion of the external components of the AFW system as plausible ARDMs because the potential exposure of carbon and alloy steels to moisture. The applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of the components in question because of the use of protective coatings. In addition, the applicant will verify the condition of those coatings through periodic system walkdowns (the structure and system walkdowns procedure is discussed in Section 3.1.3 of this SER). For those AFW components that are not readily accessible and thus are not normally within the scope of the walkdown program, the applicant plans to perform an ARDI to establish the condition of these components. For AFW components exposed internally to a steam environment, the applicant cited various forms of corrosion (including erosion/corrosion) as plausible ARDMs. The applicant manages these ARDMs primarily through chemistry controls and preventive maintenance (PM) procedures (the maintenance procedures are discussed in Section 3.8 of this SER). To verify that these programs are effective in managing these ARDMs, the applicant plans an ARDI of specific, susceptible AFW components. The applicant proposes using ARDIs of the valve internals to verify that wear and elastomer degradation need not be managed for the period of extended operation.

For the CVCS (Section 5.2), the applicant identified various forms of corrosion as plausible ARDMs for the internal surfaces of the CVCS components and the shell-side of heat exchangers that are managed primarily through its chemistry control program. To verify the effectiveness of its chemistry program, the applicant plans ARDIs of the most susceptible locations. The applicant identified wear as a plausible ARDM affecting various CVCS valves. The applicant manages this ARDM using its local leak rate test (LLRT) program (the leak rate test program is discussed in Section 3.4 of this SER). For those CVCS valves not included within the scope of the LLRT program, the applicant plans to perform ARDIs to verify that wear need not be managed for the period of extended operation.

For the CC system (Section 5.3), the applicant identified various forms of corrosion as plausible ARDMs for the internal surfaces of the CC system components that are managed primarily through its chemistry control program. To verify the effectiveness of its chemistry program, the applicant plans ARDIs of the most susceptible locations. The applicant plans to perform ARDIs of these susceptible locations in the system to verify that erosion/corrosion need not be managed for the period of extended operation. The applicant identified general corrosion as a plausible ARDM affecting the external surfaces of carbon and cast iron components because of the potential exposure to moisture. The applicant expects the effects of this ARDM to be limited because of the use of protective coatings on CC system components as well as maintenance activities associated with the CC system pumps. The applicant plans to perform an ARDI to verify that general corrosion of the CC system components externals is not occurring. The applicant identified wear as a plausible ARDM affecting CC system valves. The applicant manages this ARDM for various CC system control valves using its LLRT program. The applicant also relies on maintenance procedures for various CC system relief valves. For those CC system valves not included within the scope of the LLRT program or maintenance procedures, the applicant plans to perform ARDIs to verify that wear need not be managed for the period of extended operation.

For the CAS (Section 5.4), the applicant identified general corrosion as a plausible ARDM affecting carbon steel CAS components because of the potential exposure to moisture. However, the applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of the CAS. The instrument air (IA) system supplies the air for most CAS components. The applicant minimizes moisture in the IA system through PM procedures. However, the carbon steel containment penetration portion of the CAS is exposed to plant air, which does not have any moisture controls. For this particular portion of the CAS, the applicant plans to perform ARDIs to ensure internal corrosion is not occurring.

For the CI group (Section 5.5), the applicant identified various forms of corrosion as plausible ARDMs affecting CI group components because of long-term exposure to well water. The applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of the CI group components. In addition, the applicant credits its LLRT program with the testing of the containment isolation valves to discover corrosion. To verify that degradation of CI group components is not occurring, the applicant plans to perform ARDIs (using visual techniques) of the most susceptible locations in the system. The applicant will consider piping and component geometry as well as fluid flow conditions to determine the most susceptible locations. The applicant identified various forms of corrosion as plausible ARDMs affecting CI group components caused by exposure to water and gas from a number of sources. Because of design and chemistry controls, the applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of CI group components. In addition, the applicant credits its LLRT program with the testing of the CI group containment isolation valves to discover corrosion. The applicant plans an ARDI to verify that the CI group components exposed to water and gas are not corroding. The applicant identified wear as a plausible ARDM potentially affecting CI group valve seating surfaces. All of the Group 3 valves that perform containment pressure boundary functions are included in the applicant's LLRT program. For the valves not included within the scope of the LLRT program, the applicant plans to perform ARDIs using either visual inspection techniques or leak rate testing to verify that degradation is not occurring as a result of wear.

For the CSS (Section 5.6), the applicant identified various forms of corrosion as plausible ARDMs affecting the internals of various CSS components that are managed primarily through its chemistry control program. In addition, the applicant included several containment isolation valves in the scope of its LLRT program. Degraded conditions for these valves caused by corrosion would be detected as part of these tests. To verify the effectiveness of its chemistry program and to supplement the limited scope of its LLRT program, the applicant plans to perform ARDIs (using visual inspection techniques) of the most susceptible locations to verify that degradation is not occurring as a result of corrosion.

For the emergency diesel generator (EDG) system (Section 5.8), the applicant identified various forms of corrosion as plausible ARDMs potentially affecting the internal surfaces of various EDG system components. The applicant mitigates corrosion of the internal surfaces primarily through chemistry controls. The applicant also relies on various test procedures that minimize the exposure of internal surfaces of components to water (test procedures are discussed in Section 3.7 of this SER). The applicant also performs various maintenance procedures that may be relied upon to detect degradation of the internal components. To verify the effectiveness of its chemistry controls and test procedures and to supplement its maintenance procedures, the applicant plans to perform an ARDI (using visual inspection techniques) to verify that internal components are not corroding. The applicant also identified fatigue as a plausible ARDM affecting the EDG exhaust piping and muffler. The applicant credited a combination of a PM procedure (which provides for inspections of the external surfaces of the muffler; this maintenance procedure is discussed in Section 3.7 of this SER) and an ARDI. The applicant identified erosion/corrosion and particulate wear erosion as plausible ARDMs for the EDG cooling water piping and muffler. The applicant plans to perform an ARDI to verify that these ARDMs need not be managed for the period of extended operation. The applicant identified

MIC as a plausible ARDM affecting EDG day tanks exposed to the environment. The applicant relies primarily on its chemistry controls and surveillance test procedures to mitigate the development of MIC in the day tanks. To verify the effectiveness of these programs, the applicant plans to perform an ARDI to verify that MIC is not occurring. The applicant identified wear as a plausible ARDM affecting drain traps in the EDG system. The applicant plans to perform an ARDI using visual inspection techniques to confirm that wear need not be managed for the period of extended operation.

For the FWS (Section 5.9), the applicant identified various forms of corrosion as plausible ARDMs affecting the internal surfaces of various components in the FWS. The applicant mitigates corrosion through its use of chemistry controls. To verify the effectiveness of this program, the applicant plans to perform an ARDI using visual inspection techniques. The scope of the inspection will be biased to those portions of the system in which conditions are most likely to promote corrosion (i.e., low flow, stagnant, and crevice like areas). The applicant identified erosion/corrosion as a plausible ARDM for the FWS. Erosion/corrosion is managed primarily by an erosion/corrosion program and PM activities (these are discussed in Section 3.8 of this SER). However, the MOVs and temperature elements are not within the scope of either of those programs, so for these specific FW components, the applicant plans to perform an ARDI to verify that erosion/corrosion need not be managed for the period of extended operation.

For the fire protection (FP) system (Section 5.10), the applicant identified various forms of corrosion as plausible ARDMs for piping in the condensate system portion of this system. The applicant mitigates corrosion through its use of chemistry controls. To verify the effectiveness of its chemistry control program, the applicant plans to perform an ARDI.

For the auxiliary building heating and ventilation system (Section 5.11A), the applicant identified various forms of corrosion as plausible ARDMs affecting the internal surfaces of ducts and heat exchangers. The applicant relies primarily on protective coatings (e.g., paints and galvanization) to mitigate corrosion on the external surfaces and verifies the effectiveness of these coatings through periodic walkdowns (coatings and walkdowns are discussed in Section 3.6 of this SER). To verify that the internal surfaces of the ducts and heat exchangers are not corroding, the applicant plans to perform an ARDI. The applicant also identified elastomer degradation and wear as plausible ARDMs potentially affecting damper seals in this system. The applicant relies on the structure and system walkdowns procedure MN-1-319 to identify degradation and wear through external inspections and plans to perform an ARDI to verify that elastomer degradation and wear of the internal component surfaces of the dampers need not be managed for the period of extended operation.

For the primary containment heating and ventilation system (Section 5.11B), the applicant identified wear of various valve seating surfaces as a plausible ARDM for this system. The applicant relies on its LLRT program to detect degradation caused by wear for its containment isolation valves. For those valves not included within the scope of the LLRT, the applicant plans to perform an ARDI (using visual inspection techniques) to verify that wear need not be managed for the period of extended operation. The applicant identified various forms of corrosion that are plausible ARDMs for the system components exposed to moist air and condensation. The applicant relies on its PM program activities and its LLRT program to detect degradation from corrosion. For those components not included within the scope of the PM activities or the LLRT programs, the applicant plans to perform an ARDI to verify that corrosion need not be managed for the period of extended operation. The applicant also identified crevice corrosion and pitting as plausible ARDMs affecting the cooling coils of the containment air coolers. The applicant relies on its chemistry controls to mitigate corrosion of the internal components of the coils, and PM activities to detect degradation of the external surfaces of the coils. To verify the effectiveness of its chemistry controls, the applicant plans to perform an ARDI.

For the control room and diesel generator buildings' heating and ventilation systems (Section 5.11C), the applicant identified various forms of corrosion of carbon steel components as plausible ARDMs caused by exposure to moist air and condensation. The applicant relies primarily on protective coatings (e.g., paints and galvanization) to mitigate corrosion on the external surfaces and verifies the effectiveness of these coatings through periodic walkdowns (coatings and walkdowns are discussed in Section 3.6 of this SER) to manage corrosion of the external surfaces. For the internal surfaces, the applicant credits various PM activities. For those components not included within the scope of the PM activities, the applicant plans to perform an ARDI to verify that corrosion of various internal components in this system need not be managed for the period of extended operation. The applicant identified elastomer degradation and wear of the various duct and damper components as plausible ARDMs. The applicant relies on periodic walkdowns to detect degradation of the duct flexible collars. The applicant also performs PM activities that periodically inspect the damper seals. For those components not included within the scope of the PM activities, the applicant plans to perform an ARDI to verify that elastomer degradation and wear of dampers in this system need not be managed for the period of extended operation.

For the main steam, steam generator blowdown, extraction steam, and nitrogen and hydrogen systems (Section 5.12), the applicant identified various forms of corrosion as plausible ARDMs caused by exposure to moisture and potentially corrosive conditions. The applicant relies primarily on its chemistry controls and PM activities to mitigate corrosion in these systems. To verify the effectiveness of its chemistry controls, the applicant plans to perform an ARDI for those valves not included in the PM activities. The applicant identified erosion/corrosion and cavitation corrosion as plausible ARDMs affecting various system components. The applicant credits its chemistry controls to mitigate erosion/corrosion. The applicant relies primarily on its erosion/corrosion program and various PM activities to manage this ARDM. For those components not within the scope of the erosion/corrosion program and for those components for which cavitation corrosion is considered plausible, the applicant plans to perform an ARDI to verify that erosion/corrosion and cavitation corrosion need not be managed for the period of extended operation. The applicant identified selective leaching of specific components within the SG blowdown radiation monitor cooler as a plausible ARDM. The applicant relies primarily on its chemistry controls to limit this ARDM, but plans to perform an ARDI (using visual inspection techniques) to verify that this ARDM need not be managed for the period of extended operation. The applicant identified wear of the steam atmospheric dump valves and main steam isolation valves (MSIVs) as a plausible ARDM. The applicant relies on its PM program to verify that no wear is occurring on the MSIVs. To verify that wear need not be managed for the period of extended operation, the applicant plans to perform an ARDI to inspect the atmospheric dump valves that are not included in a PM activity.

For the NSSS sampling system (Section 5.13), the applicant identified general corrosion caused by the potential exposure of the carbon and alloy steel components of this system to concentrated boric acid as a plausible ARDM. The applicant relies primarily on its BACI program to manage this ARDM (the BACI program is discussed in Section 3.1.4 of this SER). However, the ventilation hood for the Unit 1 SG blowdown sampling subsystem is not within the scope of the BACI program. Thus, the applicant proposed performing an ARDI to verify that corrosion is not occurring. The applicant also identified various forms of corrosion of the internal surfaces of the NSSS sampling system components as plausible ARDMs. The applicant relies primarily on its chemistry controls and its LLRT to detect the presence of these ARDMs. To verify the effectiveness of these programs, the applicant plans to perform an ARDI. The applicant identified elastomer degradation in the check valves in the gas return line to containment from the PASS cabinet as a plausible ARDM. The seating surfaces for components in this group are constructed of elastomers, and degradation would result in process fluid leakage past the seal and eventual failure of the pressure boundary function. The applicant plans to perform an ARDI (using visual inspection techniques) to verify that elastomer degradation need not be managed for the period of extended operation.

For the radiation monitoring system (RMS) (Section 5.14), the applicant identified various forms of corrosion as plausible ARDMs for various carbon steel components because of the potential exposure to moisture. The applicant plans to perform an ARDI (using visual inspection techniques) to verify that corrosion need not be managed for the period of extended operation.

For the SI system (Section 5.15), the applicant identified various forms of corrosion of the internals of SI system components as potential ARDMs. They are exposed to chemically treated water and the applicant relies primarily on its chemistry controls to mitigate corrosion. In addition, the applicant relies on its pump and valve in-service testing (IST) program (discussed in Section 3.3 of this SER) to discover corrosion. However, because not all SI components are covered by the IST program and because the SI system is maintained in standby mode and does not maintain hydrogen overpressure to limit oxygen concentration, the applicant noted that some portions of the system may be vulnerable to corrosion. To supplement the pump and valve IST program and to verify the effectiveness of its chemistry controls, the applicant plans to perform an ARDI (using visual inspection techniques) to verify that corrosion need not be managed for the period of extended operation. The applicant also identified MIC of the internal surfaces, caused by exposure to stagnant borated water that is open to the containment atmosphere for extended periods of time, as a potential ARDM. To verify that MIC need not be managed for the period of extended operation, the applicant plans to perform an ARDI. The applicant identified SCC as a plausible ARDM potentially affecting the refueling water tank (RWT) penetration welds. As discussed in Section 3.3 of this SER, the applicant plans to first perform an engineering analysis to determine if the visual inspections of the outside of the RWT penetrations during system walkdowns are adequate to manage SCC at these locations. If the applicant concludes that the walkdowns are not sufficient, then the applicant plans to perform an ARDI of the RWT penetrations and associated welds to verify that unacceptable degradation, due to SCC, need not be managed for the period of extended operation.

For the SW system (Section 5.16), the applicant identified various forms of corrosion as plausible ARDMs affecting devices without internal linings exposed to saltwater either internally or externally (due to leakage). The applicant plans to perform an ARDI to verify that corrosion of the unlined SW components need not be managed for the period of extended operation. The applicant also identified various forms of corrosion as plausible ARDMs for various lined SW components because the lining could fail and expose the vulnerable material underneath to the corrosive effects of saltwater. Most of the lined components are subject to various PM activities. For those lined SW components not included within the scope of the PM program, the applicant plans to perform an ARDI, (using visual inspection techniques) to verify the integrity of the lining and to verify that corrosion is not occurring. The applicant identified various forms of corrosion affecting the CC and SRW heat exchangers. For the shell-side of the heat exchangers, corrosion is limited by chemistry controls. For the tube-side of the heat exchangers, the components are exposed to saltwater. The applicant minimizes corrosion of some heat exchanger subcomponents through the use of sacrificial anodes and protective linings. To verify that corrosion is not occurring on the shell-side, the applicant plans to perform an ARDI to verify that its chemistry controls are adequate. To detect if corrosion is occurring on the tube side, the applicant relies on its PM program to test and inspect the tube side of the heat exchangers. The applicant identified various forms of corrosion as plausible ARDMs affecting the stainless steel flow orifices in the saltwater system. All except one of the orifices are included within the scope of the applicant's existing PM program. The applicant does not include routine maintenance of this orifice because of the infrequent use of the flow path in which the orifice is installed. To verify that significant degradation is not occurring, the applicant plans to inspect the orifice as part of an ARDI.

For the SRW system (Section 5.17), the applicant identified various forms of corrosion as plausible ARDMs for the internal surfaces of various SRW system components. The applicant relies primarily on chemistry controls to mitigate corrosion of the internal surfaces. To detect corrosion, the applicant relies on the SRW pump overhaul maintenance procedure (the procedure is discussed in Section 3.5 of this SER). To verify the effectiveness of its chemistry controls, the applicant plans to perform an ARDI that will include all SRW components except the SRW pumps. The applicant plans to perform an ARDI of the most susceptible locations in the SRW system to verify that erosion/corrosion need not be managed for the period of extended operation. The applicant identified general corrosion as a plausible ARDM for various carbon steel and cast iron subcomponents. The applicant mitigates corrosion through its chemistry controls and IA quality controls (the IA quality controls are discussed in Section 3.5 of this SER). The applicant relies on various maintenance procedures to identify corrosion. To verify the effectiveness of its chemistry and air quality controls and to supplement its PM program, the applicant plans to perform an ARDI to verify that corrosion is not occurring. The applicant identified selective leaching as a plausible ARDM affecting some cast iron pumps and valves within the system. The applicant relies primarily on its chemistry controls to manage this ARDM. The applicant plans to perform an ARDI to verify that the chemistry controls are effective.

For the SFPCS (Section 5.18), the applicant identified various forms of corrosion affecting carbon steel SFPCS components. The applicant relies primarily on its BACI program, its chemistry controls, and protective coatings (zinc plating or paint) to mitigate corrosion. The applicant also relies on its BACI program to detect borated water leakage that may result in corrosion of SFPCS components. However, some SFPCS components are not within the scope of the BACI program because of ALARA (as low as reasonably achievable) concerns, and some SFPCS components are not accessible for general inspections via a walkdown. To verify the effectiveness of its chemistry controls and to supplement its BACI program, the applicant plans to perform an ARDI (using visual inspection techniques) to verify that these components are not corroding. The applicant also identified elastomer degradation of various valve seats exposed to borated water. The applicant plans an ARDI to inspect these valves to verify that elastomer degradation need not be managed for the period of extended operation.

3.1.6.3 Staff Evaluation

Although treated similarly to other aging management programs, ARDIs actually supplement existing aging management programs by providing additional assurance that either: (1) an ARDM need not be managed for the period of extended operation or (2) the current aging management programs are effective in managing aging effect. The applicant has restricted its use of ARDIs to those specific instances in which an ARDM cannot be categorically ruled out or when it would be beneficial to have inspection results to provide direct evidence that an aging management program is effective. The staff considers this limited use of one-time ARDIs acceptable. The staff's evaluation of the specific inspection attributes follows. The staff focused its evaluation of ARDIs on the inspection attributes, such as (1) program scope, (2) parameters monitored or inspected, (3) detection of aging effects, (4) acceptance criteria, (5) corrective actions, (6) confirmation process, (7) administrative controls, and (8) operating experience.

As summarized in Section 3.1.6.2, the applicant has proposed ARDIs or other similar programs for managing ARDMs related to valve or damper internals. However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve or damper internals (such as wear and elastomer degradation) because valve and damper internals perform their intended function with moving parts and changes in configuration and are, therefore, not subject to an AMR for license renewal.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with a site-controlled corrective action program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is reported separately in Section 3.1.5 of this SER. As determined in Section 3.1.5 or this SER, the staff finds that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about ARDIs included in Sections 4.3, 5.1, 5.2, 5.3, 5.4, 5.5, 5.6, 5.8, 5.9, 5.10, 5.11A, 5.11B, 5.11C, 5.12, 5.13, 5.14, 5.15, 5.16, 5.17, and 5.18 of Appendix A to the LRA. By letter dated April 8, 1998, the applicant submitted its LRA. By letter dated August 28, 1998, the staff issued an RAI requesting more detail pertaining to ARDIs. By letter dated November 12, 1998, the applicant responded, in part, to the staff's RAI. The applicant presented additional information related to ARDIs in a meeting with the staff on February 10, 1999 (NRC meeting summary dated March 19, 1999).

Program Scope

The staff finds the scope of ARDI inspections to be acceptable because the applicant has included a comprehensive coverage of systems and has biased the inspections to those components most likely to exhibit an aging effect.

In Open Item 3.1.6.3-1 in the CCNPP March 21, 1999, SER, the staff requested that the applicant submit additional information to support the use of one-time ARDIs in cases in which appeared to the staff that regular, periodic inspections were required to manage aging effects. In its response dated July 2, 1999, the applicant sent additional information for each specific instance cited by the staff. Each case is discussed individually below:

- For the auxiliary feedwater (AFW) system, the applicant reported that corrosion of the external components of the AFW system from the potential exposure of carbon and alloy steels to moisture is a plausible aging effect. The applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of the components in question because of the use of protective coatings. In addition, the applicant verifies the condition of these coatings on a continuing basis through periodic system walkdowns. For those limited AFW components that are not readily accessible and thus are not normally within the scope of the walkdown program, the applicant plans to perform an ARDI to establish the condition of these components. The staff questioned the appropriateness of substituting a one-time inspection for a regular, periodic inspection such as a walkdown. In its July 2, 1999, response, the applicant submitted additional information regarding the scope and intended purpose of the ARDI for the AFW system. The AFW components that are not normally within the scope of the system walkdown procedure are those in the No. 12 condensate storage tank (CST) enclosure and the valve pit. The components in question are heat traced and covered by insulation. The applicant believes these components are adequately protected from moisture, but plans to perform a one-time ARDI to verify its assumption that the enclosures and insulation are adequately weatherproofed to protect the external surfaces of the AFW components. The condition of the insulation and piping documented by this ARDI will form the basis to determine whether further actions, such as future inspections, are required. The staff finds the additional information provided by the applicant in its July 2, 1999, letter supports the application of a one-time ARDI to this system. The use of an ARDI for the CST enclosure and valve pit appears consistent with the intended purpose of ARDIs because the AFW components in these areas are protected from direct exposure to moisture as a result of the components being enclosed and covered with insulation. This is in contrast to the remaining AFW components that are not afforded such dual protection and benefit from the system walkdown procedure. The staff considers this issue closed.

- For the component cooling (CC) system, the applicant reported that corrosion of the external components of the CC system due to the potential exposure of carbon steel and cast iron to moisture is a plausible aging effect. The applicant expects the occurrence of corrosion to be limited and unlikely to affect the intended function of the components in question because of the use of protective coatings. The applicant plans to perform an ARDI to verify that general corrosion of the CC system components externals is not occurring. The staff noted in its previous SER that a one-time ARDI is not the appropriate vehicle for managing this aging effect. Regular, periodic inspections need to be performed to ensure degradation of the coatings is not occurring. In its July 2, 1999, response, the applicant sent additional information regarding the potential for corrosion of the CC system components. The applicant clarified that it does not consider general corrosion of the external surfaces of these components to be a plausible aging effect. The CC system components are not exposed to the elements because they are located in the containment and auxiliary buildings and are additionally protected through the use of protective coatings. The staff agrees that general corrosion of the external surfaces of the CC system components, if it does occur at all from degradation of the coatings, will be superficial and extremely unlikely to affect the intended function of the CC system components. Thus, the staff finds the use of a one-time ARDI to verify this assumption appropriate. The staff considers this issue closed.

- For the NSSS sampling system, the applicant reported that general corrosion caused by the potential exposure of the carbon and alloy steel components of this system to concentrated boric acid is a plausible aging effect. The applicant relies primarily on its BACI program to manage this ARDM. However, the ventilation hood for the Unit 1 steam generator blowdown sampling subsystem is not within the scope of the BACI program, and the applicant proposed performing an ARDI to verify that corrosion is not occurring. The staff noted in its previous SER that a one-time ARDI is not the appropriate vehicle for managing this aging effect. Regular, periodic inspections need to be performed. In its response dated July 2, 1999, the applicant stated that it has reassessed this aging effect and determined that the ventilation hood would not be exposed to concentrated boric acid because there are no potential borated water leakage sites near the hood. Thus, there is no longer a need to perform inspections of the ventilation hood. All other locations of plausible external corrosion in this system are covered by the BACI program. The staff considers this issue closed.

- The previous CCNPP SER dated March 21, 1999 incorrectly characterized the staff's concern with the SW system ARDI. The issue did not relate to the inspection of rubber-lined SW components. The issue related to unlined SW components. This was discussed with the applicant, and the applicant's response to the previous SER reflects this correction. The resolution of the issue is discussed below.

  For the SW system, the applicant reported that corrosion of various devices without protective coatings from exposure to saltwater either internally or externally (from leakage) is a plausible aging effect. The applicant plans to perform an ARDI to verify that corrosion of the unlined SW components need not be managed for the period of extended operation. For those unlined or uncoated components fabricated from corrosion-resistant materials such as red brass, copper-nickel, bronze, stainless steel, and Monel, the staff accepts the use of a one-time ARDI because corrosion of these materials is expected to be minimal. However, for the uncoated carbon and low-alloy steel components that may be exposed to saltwater externally from leakage, the staff found the use of a one-time ARDI unacceptable because regular, periodic inspections are required to manage this aging effect. In a letter to the staff dated April 2, 1999, the applicant committed to performing regular, periodic walkdowns in accordance with plant procedure MN-1-319. The staff finds this acceptable because the unprotected carbon and alloy steel bolting in the SW system will receive periodic inspections to ensure that corrosion from leakage of saltwater is managed before there is a loss of intended function. The staff considers this issue closed.

- For the SFPC system components, the applicant reported that general corrosion caused by the potential exposure of the carbon and alloy steel components of this system to concentrated boric acid is a plausible aging effect. The applicant relies primarily on its BACI program to manage this ARDM. However, five SFPC system components are not within the scope of the BACI program because of radiation levels or because they are not readily accessible for general inspections via a walkdown. The applicant proposed performing an ARDI to verify that corrosion from exposure to concentrated boric acid is not occurring. The staff noted in its previous SER that a one-time ARDI is not the appropriate vehicle for managing this aging effect. Regular, periodic inspections need to be performed. In its response dated July 2, 1999, the applicant stated that it has included three of the five components in the scope of the BACI program. The remaining two components will be inspected for corrosion through modification of an existing PM program which is performed every two years. The applicant has committed to modifying the PM program repetitive task 10672001 to include inspections for corrosion from exposure to concentrated boric acid. The staff finds this proposal acceptable because all five components will be subject to regular, periodic inspections to ensure aging due to the potential exposure to concentrated boric acid is managed.

On the basis of the response to Open Item 3.1.6.3-1, as presented in the applicant's July 2, 1999, letter, the staff concludes that the applicant has provided sufficient information to support its position that a one-time ARDI is sufficient to ensure that the components of the AFW system that are not readily accessible during periodic system walkdowns will be inspected to adequately manage aging effects. In addition, the applicant clarified that CC external components and the NSSS sampling system ventilation hood are not subject to general corrosion. Finally, the applicant has committed to perform regular, periodic walkdowns to identify corrosion in uncoated carbon and low-alloy steel components in the SW system; to including three additional components of the SFPC system in the BACI program; and to modifying an existing PM program to inspect two SFPC system components. On the basis of these commitments, the staff has reasonable assurance that the applicant can manage the aging effects associated with these systems to ensure their continued functionality during the period of extended operation. The staff considers Open Item 3.1.6.3-1 closed.

Parameters Monitored

The staff finds the parameters monitored (e.g., evidence of pits, corrosion, erosion/corrosion, wear, and boric acid residue) acceptable because these parameters are directly related to the degradation of a component. The applicant relies primarily on visual inspection techniques that are appropriate for most of the ARDMs included within the scope of the ARDIs. Supplemental techniques, such as dye penetrant testing, ultrasonic testing, or magnetic particle testing, may also be used by the applicant as appropriate (e.g., use of ultrasonic testing to verify adequate wall thickness).

Detection of Aging Effects

The staff finds the various nondestructive evaluation techniques cited by the applicant acceptable for detecting aging effects because their use has been proven effective for all the types of ARDMs to which the applicant plans to apply them. The applicant performs ARDIs using qualified techniques and personnel, which is consistent with staff expectations and enhances the effectiveness of the ARDIs. With respect to inspection timing, the applicant did not give the staff the ARDI schedule other than to state that ARDIs are planned to be completed before the current operating license expires (that is before the end of the 40th year of operation). The staff expects that the applicant will schedule ARDIs in such a way as to minimize impact on plant operations; therefore, inspections will most likely be performed fairly regularly over the next two decades. The staff did not identify the need for a specific commitment from the applicant to perform an ARDI at a particular time. Thus, recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the LRA, the staff accepts the applicant's general commitment to complete the ARDIs before the end of the 40th year of operation because staff expects minimal progression for all the aging effects resulting from the various ARDMs (corrosion, erosion, wear, elastomer degradation, elastomer hardening, cracking, thermal aging, synergistic thermal and radiative aging) subjected to ARDIs due to the robust design and relatively benign operating conditions. In conclusion, the staff finds that the inspection scope, technique, procedure, and schedule support the applicant's intention of confirming that these ARDMs need not be managed for the period of extended operation. The applicant presented information in the LRA that the effects of these ARDMs will be minimal; thus, the staff also concludes that the ARDIs may be relied upon to detect aging effects before there is a loss of intended function.

Acceptance Criteria

The staff finds the applicant's acceptance criteria acceptable because the applicant indicated that any evidence of the presence of an aging effect will be evaluated.

Operating Experience

The use of ARDIs is a new technique to be applied by the applicant. Thus, although there exists no operating experience to support the successful application of ARDIs, the elements that comprise the ARDIs (e.g., the scope of the inspections and the inspection techniques) are consistent with years of industry practices and staff expectations.

3.1.6.4 Conclusions

The staff has reviewed the compilation of one-time ARDI inspections in Sections 4.3, 5.1, 5.2, 5.3, 5.4, 5.5, 5.6, 5.8, 5.9, 5.10, 5.11A, 5.11B, 5.11C, 5.12, 5.13, 5.14, 5.15, 5.16, 5.17, and 5.18 of Appendix A to the LRA as well as additional information sent by the applicant in response to the staff's RAI and information presented during a public meeting (NRC meeting summary dated March 19, 1999, for February 10, 1999, public meeting). On the basis of the staff's review as stated above, the staff concludes that the applicant has demonstrated that the ARDIs are an effective aging management tool and the application of the ARDI program will provide reasonable assurance that the SSCs for which ARDIs are used will perform their intended functions in accordance with the CLB during the period of extended operation.

The staff concludes that the applicant has submitted enough information in its LRA to show that the ARDIs are an effective aging management tool.

3.2 Reactor Vessel, Reactor Vessel Internals, and Reactor Coolant System

3.2.1 Introduction

The applicant described its AMR of the reactor vessel, RVIs, and reactor coolant system (collectively called RVIC) for license renewal in three separate sections of Appendix A to the LRA: Section 4.1, "Reactor Coolant System"; Section 4.2, "Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System"; and Section 4.3, "RVIs System," of Appendix A to the LRA. The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the RVIC will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2 Summary of Technical Information in the Application

3.2.2.1 Structures and Components Subject to an Aging Management Review

In Section 4.1 of Appendix A to the LRA, the applicant described the RCS. The RCS removes heat from the reactor core and internals and transfers it to the steam generating system. For each unit, the RCS consists of two heat transfer loops connected in parallel across the RPV. Each loop contains one steam generator, two reactor coolant pumps, and connecting piping. Other major components are a quench tank and a pressurizer connected to one of the RCS loop hot legs for maintaining coolant system pressure. The RCS is seismic Category I, is located within the containment, and is constructed of stainless steel in most components and Alloy 600 in some components. The internal environment consists of chemically treated borated water. The applicant's determination of device types requiring an AMR is shown in Table 4.1-2 of Appendix A to the LRA.

In Section 4.2 of Appendix A to the LRA, the applicant described the RPV. The RPV, which houses the reactor core and its supporting structures, is connected to the RCS piping. The RPV of each unit is comprised of a removable head with multiple penetrations; four primary coolant inlet nozzles; two primary coolant outlet nozzles; upper, intermediate, and lower shell courses; and a bottom head and vessel supports. Each vessel is approximately 503.75 inch high, 172 inch inside diameter, and is an all-welded manganese molybdenum steel plate and forging construction. The RPV is seismic Category I, and the internal environment consists of pressurized and rapidly flowing borated water, with high irradiation from the reactor core. The applicant's determination of device types requiring an AMR is shown in Table 4.2-1 of Appendix A to the LRA.

In Section 4.3 of Appendix A to the LRA, the applicant described the RVI system. The major components of the RVI structures are the core support barrel, the lower core support structure, and the upper core support structure, which includes CEA shrouds and incore instrumentation guide tubes. The RVI is seismic Category I, is located inside the RPV, and is constructed of stainless steel. The internal environment consists of pressurized and rapidly flowing borated water, with high irradiation from the reactor core. The applicant's determination of device types requiring an AMR is shown in Table 4.3-1 of Appendix A to the LRA.

3.2.2.2 Effects of Aging

The applicant determined that aging effects from the following ARDMs should be managed for license renewal: steam generator tube denting, erosion, erosion/corrosion, galvanic corrosion, general corrosion, intergranular attack (IGA), pitting, various forms of SCC [including intergranular stress corrosion cracking (IGSCC) and primary water stress corrosion cracking

(PWSCC)], thermal aging, neutron embrittlement, fatigue, wear, and stress relaxation. The applicant's evaluation of aging effects is summarized in Tables 4.1-3, 4.2-2, and 4.3-2 of Appendix A to the LRA.

The applicant submitted information on the operating experience of the RVIC systems related to aging degradation. The RCPs have experienced fragmented bolting, cracked welds and seals, and cracks at the thermal barrier housing from flow-induced vibrations. The Alloy 600 components have experienced pressure boundary leaks from PWSCC. Steam generator tubes have degraded because of IGA, SCC, and denting.

3.2.2.3 Aging Management Programs

In Tables 4.1-4, 4.2-3, and 4.3-3 of Appendix A to the LRA, the applicant identified the following programs (existing, modified, and new) and plant maintenance procedures for license renewal, which will provide adequate aging management for the RVIC systems:

- Existing CCNPP surveillance test procedure STP-M-574-1/2, "Eddy Current Examination of CCNPP Units 1 and 2 SGs," for discovering denting, wear, SCC, and pitting in steam generator tubes

- Modified CCNPP administrative procedure MN-3-110, "ISI of ASME Section XI Components," for detecting wear, erosion/corrosion, and SCC of RCS and RPV components (present), and modified to specifically identify which RVI components use this program for management of wear, neutron embrittlement, and high-cycle fatigue

- Existing CCNPP administrative procedure MN-3-301, "Boric Acid Corrosion Inspection Program," for detecting wear, erosion, general corrosion, and SCC of RVIC components

- Existing CCNPP surveillance test procedure STP-0-27-1/2, "Reactor Coolant System Leakage Evaluation," for detecting through-wall leakage of steam generator tubes; mitigating the effects of steam generator tube wear, denting, and various forms of SCC; and SCC of the RV flange leakoff lines.

- Existing CCNPP chemistry procedures CP-204, "Specifications and Surveillance for Primary Systems," and CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," for monitoring and controlling water chemistry to mitigate corrosion of RVIC components

- Existing CCNPP technical procedure CP-217, "Specifications and Surveillance: Secondary Chemistry," for managing the effects of denting, pitting, and SCC of steam generator tubes.

- Existing CCNPP maintenance procedure RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation" for mitigating SCC on the RPV head seal leakage detection line

- Existing CCNPP maintenance procedure RV-22, "RPV O-Ring Replacement," for discovering general corrosion on the RPV head and vessel

- Existing CCNPP maintenance procedure RV-85, "ICI Flange Cleaning and Inspection," for discovering wear on the ICI tube nozzle flanges and associated components

- Existing CCNPP maintenance procedure RV-62, ""RPV Stud, Nut, and Washer Cleaning and Inspection," for discovering wear and general corrosion on the RPV studs, nuts, and washers

- Existing CCNPP program, "Comprehensive Reactor Vessel Surveillance Program," (CRVSP) for managing neutron embrittlement of the RPV

- Modified CCNPP procedure EN-1-300, "Fatigue Management Program," for tracking the number of critical thermal and pressure transient cycles and performing fatigue evaluation of the RCS (RCPs, MOVs, pressurizer RVs, and CEDM/RVLMS components will be included after program modification.)

- Modified CCNPP Alloy 600 program plan for managing various forms of SCC in RVIC components fabricated from Alloy 600 (Alloy 600 weld metal, RCS nozzle thermal sleeves, and all non-pressure boundary Alloy 600 components will be included after program modification if these components are not bounded by existing components.)

- Modified CCNPP procedure RVLMS-2, "Installation of the Flexible HJTC in the Reactor," for discovering wear on RVLMS flanges and associated components (Will be modified to perform inspections of studs, nuts, and seal plugs.)

- New CASS evaluation program to manage thermal aging embrittlement of RVIC components fabricated from CASS

- New program to perform low-cycle fatigue analysis of components subject to gamma heating
- New program to perform delta ferrite calculation for CASS components

- New program for performing stress relaxation analysis of CEA shroud bolts and core shroud tie rods, nuts, and set screws

- New program for performing SCC analysis of CEA shroud bolts

- New ARDI program for detecting aging 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

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the RVIC systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.2.2.4 Time-Limited Aging Analyses

In Section 2.1, "Time-Limited Aging Analyses," of Appendix A to the LRA, the applicant indicates that the following time-limited aging analyses (TLAAs) are applicable to the RVIC systems:

- Embrittlement of the reactor pressure vessel from neutron irradiation, including pressurized thermal shock requirements (10 CFR 50.61), low-temperature overpressure protection, power-operated relief valve setpoints and administrative controls, and plant heatup/cooldown (pressure/temperature or P/T) curves; and

- Fatigue analyses to predict cumulative effects on the reactor vessel, reactor coolant system piping, pressurizer, pressurizer auxiliary spray line, and pressurizer surge line.

3.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 4.1, 4.2, and 4.3 of Appendix A to the LRA regarding the applicant's demonstration that aging effects will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation for the RVIC systems. After completing the initial review, by letters dated August 26, September 2, and September 3, 1998, the staff issued several requests for additional information (RAIs). By letters dated November 2, 4, and 19 and December 10, 1998, the applicant responded to the staff's RAIs. The staff also met with the applicant on February 10 and 16, 1999 (NRC meeting summaries dated March 19, 1999) to discuss its responses to the RAIs.

The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER.

3.2.3.1 Effects of Aging

As described in Section 3.2.2.2 above, the applicant determined that the aging effects from the following ARDMs should be managed for license renewal: denting, erosion, erosion/corrosion, galvanic corrosion, general corrosion, IGA, pitting, SCC (including IGSCC and PWSCC), thermal aging embrittlement, neutron embrittlement, fatigue, wear, and stress relaxation. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds the applicant's approach to identifying ARDMs acceptable because aging effects are the result of ARDMs. The staff's analysis of the ARDMs identified by the applicant is set forth below.

For evaluation, the staff categorized the applicant's identification of ARDMs into three major reviews: (1) aging effects caused by material degradation (e.g., denting, erosion, erosion/corrosion, galvanic corrosion, general corrosion, IGA, pitting, SCC, thermal aging embrittlement, and neutron embrittlement), (2) aging effects caused by fatigue, and (3) aging effects caused by wear and stress relaxation.

3.2.3.1.1 Aging Effects Caused by Material Degradation

On the basis of operational experience and potential and plausible ARDMs described in Sections 4.1.1 and 4.1.2 of Appendix A to the LRA, the staff focused its evaluation of aging effects of RVIC components on the following areas. On the basis of industry experience and data, as set forth below, the staff concluded that no additional aging effects are applicable for this section of the SER.

A. Steam Generators

For the steam generators, the applicant determined that the aging effects caused by the following age related degradation mechanisms (ARDMs) should be managed for license renewal: denting, erosion/corrosion, general corrosion, pitting, intergranular attack (IGA), and various forms of stress corrosion cracking (SCC). If not actively managed, these ARDMs may result in the steam generators not meeting their intended function through cracking or loss of material.

Denting of the steam generator tubes occurs from corrosion of the tube support structures. The corrosion products have a lower density than the base metal and tend to fill the space between the tube and the support. Continued corrosion of the support eventually causes the tube to mechanically deform (or dent). Although not a safety issue in and of itself, denting has been shown to promote the occurrence of PWSCC. Steam generator components experience erosion/corrosion in environments with high-velocity water flow (single or two-phase) having flow disturbances, low oxygen content, and a fluid pH less than 9.3. The external surfaces of the carbon and alloy steel components of the steam generators have the potential to corrode from exposure to concentrated boric acid. The internal portions of the steam generator (e.g., tube support structures) could corrode from exposure to the secondary-side environment (see denting discussion above). Pitting and IGA affect the steam generator tubes upon exposure to the secondary-side environment. SCC (including IGSCC and PWSCC) is an applicable ARDM affecting the steam generator instrument nozzles, steam generator tubes, and steam generator bolting studs. The instrument nozzles and tubes, fabricated from Alloy 600 and exposed to reactor coolant, are susceptible to PWSCC. The Alloy 600 steam generator tubes are also susceptible to IGSCC and IGA from exposure to the secondary-side environment. The steam generator manway bolting studs are susceptible to SCC from potential exposure to such corrosive anions as oxygen, chloride, fluoride, sulfates, and other sulfur-containing ions. On the basis of the description of the steam generator internal and external environments and materials, the staff concludes that the applicant has considered plausible ARDMs that are consistent with published literature and industry experience.

In Open Item 3.2.3.1.1-1 as described in the March 21, 1999, CCNPP SER, the staff requested that the applicant clearly identify erosion/corrosion of the steam generator tube carbon steel eggcrate supports as a plausible aging mechanism and provide the specific inspection scope, inspection frequency, and acceptance criteria for inspections performed to ensure that aging effects attributed to erosion/corrosion are adequately managed. In its July 2, 1999 response, the applicant stated that erosion/corrosion is a plausible aging mechanism for the carbon steel eggcrate support. The applicant credited administrative procedure EN-4-106, "Steam Generator Tube Surveillance Program," with management of this aging mechanism and the resulting aging effects (i.e., loss of material). The program is evaluated in Section 3.2.3.2 of this SER. The staff considers Open Item 3.2.3.1.1-1 closed.

B. Pressurizer and Other RCS Components

For the pressurizer, the applicant determined that the ARDMs of general corrosion, various forms of SCC, and thermal aging embrittlement should be managed for license renewal. If not actively managed, these ARDMs may result in the pressurizer not meeting its intended function because of cracking or loss of material.

The external surfaces of the carbon and alloy steel components of the pressurizer may corrode from exposure to concentrated boric acid. The applicant noted that the following pressurizer components are susceptible to this ARDM: pressurizer shell and heads, safety/relief valves, spray and surge nozzle forgings, manway forging, manway cover plate, manway bolting, welds, support rings assembly and base ring assembly, support skirt forging, and lifting lugs.

SCC (including IGSCC and PWSCC) is an applicable ARDM affecting Alloy 600, stainless steel, and alloy steel pressurizer components. The pressurizer components fabricated from Alloy 600 and exposed to reactor coolant are susceptible to PWSCC. The stainless steel and alloy steel components are susceptible to SCC/IGSCC from potential exposure to corrosive anions in the reactor coolant— such as oxygen, chloride, fluoride, sulfates, and other sulfur-containing ions. The applicant identified the following pressurizer components as susceptible to this ARDM: pressure, level, and temperature nozzle forgings (except for Unit 2 upper pressure and level forgings); pressure, level, temperature, safety/relief valve, and spray nozzle safe ends; surge nozzle safe ends; spray and surge nozzle thermal sleeve; Unit 1 heater sleeve (the Unit 2 heater sleeves are fabricated from Alloy 690); and Alloy 600 welds. On the basis of the description of the pressurizer internal and external environments and materials, the staff finds that the applicant has included plausible ARDMS that are consistent with published literature and industry experience.

The applicant stated that it evaluated the loss of preload of RCP closure bolting and safety and relief valve closure bolting under the category of corrosion and SCC. The staff finds that the temperatures are too low for stress relaxation, and believes that loss of preload is a plausible aging effect caused by such ARDMs as general corrosion and SCC. Thus, if these ARDMs are adequately managed, loss of preload will be accounted for.

For the remaining portions of the RCS pressure boundary, the applicant determined that the aging effects from the following ARDMs should be managed for license renewal: general corrosion, galvanic corrosion, erosion, IGA, SCC, and thermal aging embrittlement. If not actively managed, these ARDMs may result in the RCS components not meeting their intended functions because of cracking or loss of material.

The external surfaces of the carbon and alloy steel components of the RCS may corrode because of potential exposure to concentrated boric acid. The applicant identified the following RCS components as susceptible to this ARDM: piping, elbows, nozzles, safe ends, and pump/valve closure bolting. The cast austenitic stainless steel reactor coolant pump (RCP) case and pump cover may erode from exposure to high-velocity steam, water, or a two-phase mixture, which may contain abrasive particles. The stainless steel RCP seal water heat exchangers may experience IGA from exposure to an aggressive water chemistry. Alloy 600, stainless steel, and alloy steel components of the RCS may experience SCC from exposure to an aggressive water chemistry. SCC (including IGSCC and PWSCC) is an applicable ARDM affecting Alloy 600, stainless steel, and alloy steel RCS components (e.g., instrument nozzles, thermal sleeves and fittings). The RCS components fabricated from Alloy 600 steel and exposed to reactor coolant are susceptible to PWSCC. The stainless steel and alloy steel components are susceptible to SCC/IGSCC because of potential exposure to such corrosive anions in the reactor coolant as oxygen, chloride, fluoride, sulfates, and other sulfur-containing ions. The applicant identified the following RCS components as susceptible to this ARDM: charging nozzle thermal sleeve, resistance temperature detector nozzle, pressure/sample nozzle neck, safety injection thermal sleeve, RPV head closure seal leakage detection piping, fittings, welds, valve bodies and bonnets, and spray line nozzle safe end. Thermal aging embrittlement of RCS components fabricated from cast austenitic stainless steel (CASS) may result in embrittlement of the material from long-term exposure to high temperature. The applicant identified the following RCS components as susceptible to this ARDM: surge piping, surge elbows, surge nozzle safe ends, shutdown cooling safe end, safety injection nozzle safe end, and the RCP casing and cover. On the basis of the description of the RCS internal and external environments and materials, the staff concludes that the applicant has included all plausible ARDMS that are consistent with published literature and industry experience.

Aging Management Review

The staff found the applicant's descriptions of plausible ARDMS affecting the pressurizer and RCS to be acceptable but also found that the applicant did not discuss the basis for concluding why several pressurizer and RCS components were not susceptible to the ARDMs discussed above. To ensure adequate scope for AMPs, the staff questioned the applicant's basis for concluding that the following components were not susceptible to SCC:

- The pressurizer shell/heads (including cladding cracking), the spray line nozzle forging, the surge line forging and safe end, the manway cover plate, and the support skirt

- Carbon steel components in hot-leg and cold-leg piping, nozzles, and safe ends

- Stainless steel components of RCP nozzles, safety and relief valve bodies and body flanges, bonnet and bonnet flanges and nozzles, hot- and cold-leg piping, surge line, spray line, auxiliary piping (i.e., piping connecting to the decay heat removal system) for the core flood system, and other Class 1 piping, nozzles, and safe ends

- CASS components of RCP casing and cover, casing flange, cover flange; safety and relief valve bodies, bonnets, body and bonnet flanges; surge line and nozzles

In view of industry experience and data, the staff considered SCC to be plausible for these pressurizer and RCS components, and believed it should be managed by AMPs. The staff would have considered the following existing programs acceptable for managing the effects of SCC as AMPs or portions of AMPs:

- ASME XI

- Technical specifications leakage requirements

- Program based on the provisions of NRC Bulletin 82-02, "Degradation of Threaded Fasteners in the RCS Pressure Boundary of PWR Plants"

- Primary water chemistry control program

The staff indicated it would have found these programs acceptable to manage SCC for the specified pressurizer and RCS components, along with a description of and implementation commitment from the applicant to manage threaded fasteners in accordance with Bulletin 82-02. Otherwise, the applicant was to have proposed an acceptable alternative. This was identified as Open Item 3.2.3.1.1-2.

By letter dated October 22, 1999, the applicant responded to this open item, stating that SCC was not plausible for a number of components of carbon steel, wrought and cast stainless steel, and cladding. The applicant's review of operating experience showed no cases of internal SCC. The applicant maintained that internal SCC was not plausible on the basis of chemistry controls.

The applicant did find cases of external transgranular SCC, which it attributed to human activities and to cement containing high chlorides used for binding heat tracing to piping. The applicant has been replacing all heat tracing that used this cement. To show that external SCC is not plausible, the applicant stated that all piping with a normal operating temperature of 160°F is insulated and jacketed with stainless steel. The only parts of the RCS that would not be insulated are instrument lines that are normally at 160°F or less. The applicant stated that these lines are not susceptible because there is not a plausible source of chloride contamination, and since the lines are uninsulated, there is no enveloping material to support an aqueous environment.

The staff agrees with the applicant's determination. Internal SCC is not likely on the basis of water chemistry controls used in PWRs. The possibility of SCC occurring during cooldown because of oxygen being introduced is unlikely on the basis of the short duration of this state. Concerning whether air pockets promoting SCC could exist in the RCS, the applicant stated that it completely vents the system, thus precluding the existence of air pockets. In the unlikely event that the cladding should crack from SCC, such cracking has been shown not to propagate into base metal.

The stainless steel jacketing will protect the piping from external SCC, and the unjacketed lines should not be susceptible for the reasons the applicant stated above. External SCC caused by human activities that the applicant described does not warrant an aging management program. Eliminating the cement will remove the cause of external SCC found at CCNPP.

On the basis of the information submitted by the applicant in the letter dated October 22, 1999, and summarized above, the staff finds that the applicant has provided an acceptable basis on which to conclude that several pressurizer and RCS components are not susceptible to SCC. This closes Open Item 3.2.3.1.1-2.

C. Reactor Pressure Vessel and Internals

For the RPV and RVI, the applicant determined that the aging effects from the following ARDMs should be managed for license renewal: general corrosion, neutron embrittlement, thermal aging embrittlement, and various forms of SCC. If not actively managed, these ARDMs may result in the RPV/RVI components not meeting their intended function because of cracking, loss of material, or reduction of fracture toughness.

The external surfaces of the carbon and alloy steel components of the RPV may potentially corrode from exposure to concentrated boric acid. The applicant identified the following RPV components as susceptible to this ARDM: the unclad external surfaces of the RPV upper/lower head/shell plates and their welds; RPV and closure head flanges, inlet and outlet nozzles, and nozzle safe ends; RPV closure head studs, nuts, and washers; RPV supports; and RPV nozzle welds.

Neutron embrittlement can occur in stainless steel, alloy steel, and low alloy steel exposed to neutron irradiation during plant operation. With sufficiently high levels of neutron fluence, these steels may undergo microstructural changes that result in a loss of ductility and fracture toughness. The applicant identified the following RPV components as susceptible to this ARDM: RPV plates and welds of the lower shell, intermediate shell, and the lower portion of the nozzle shell courses. For the RVI, the following components were determined to be susceptible to neutron embrittlement: the CEA shroud and bolts (excluding the spanner nuts and tabs), core shroud, core shroud tie rod and bolts, core support barrel, core support columns, core support plate, fuel alignment pins, fuel alignment plate/guide lug insert, and the lower support structure beam assembly.

Thermal aging embrittlement refers to loss of fracture toughness caused by long-term exposure to high temperatures of components fabricated from CASS. The applicant identified the following RPV/RVI components as susceptible to this ARDM: the CEA shroud assembly tubes and the core support columns.

The applicant concluded that the RPV/RVI components fabricated from Alloy 600 or X-750 and exposed to reactor coolant are susceptible to PWSCC. The stainless steel and alloy steel components are susceptible to SCC/IGSCC from potential exposure to such corrosive anions in the reactor coolant as oxygen, chloride, fluoride, sulfates, and other sulfur-containing ions. The applicant identified the following RPV/RVI components as susceptible to PWSCC/SCC/IGSCC: CEA shroud bolts; RPV leakage monitoring tube, RPV ICI tube nozzles, vent pipe and CEDM nozzles; RPV flow skirt, RPV core stop lugs; RPV core stabilizing lugs; RPV surveillance capsule holders; and RPV supports anchor bolts.

On the basis of the description of the RPV and RVI internal and external environments and materials, the staff concludes that the applicant has included all plausible ARDMs that are consistent with published literature and industry experience. Areas in which the staff either did not agree with the applicant's findings or requested clarification of its findings are outlined below.

(1) Non-plausible aging effects for reactor vessel components

Although the staff finds the applicant's descriptions in the initial application of plausible ARDMs affecting the RPV in the application to be generally acceptable, the staff also found that the applicant did not discuss the basis for concluding why several RPV components were not susceptible to the ARDMs discussed above. In response to NRC Question No. 4.2.14, the applicant adequately described the basis for finding that the specific aging effects identified by the staff's RAI question were not plausible or not potential aging effects. Among the bases for the findings of non-plausibility is that the material is not susceptible to the degradation mechanism (e.g., austenitic stainless steel is not susceptible to general corrosion), or the component environment is not conducive to the degradation mechanism (e.g., primary coolant nozzles are not located in a high neutron flux location).

(2) Non-plausible aging effects for RVI components

Although the staff found the applicant's descriptions in the initial application of plausible ARDMs affecting the RVI to be generally acceptable, the staff also found that the applicant did not discuss the basis for concluding why several RVI components (as referenced in RAI 4.2.14 in NRC letter dated August 26, 1998) were not susceptible to specific ARDMs identified by the staff. During a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), the applicant agreed to summarize the internal documentation, including identification of the materials used to fabricate the component, description of the basis for the non-plausibility finding, and identification of references that document the finding. This documentation was provided by electronic mail subsequent to the meeting on February 16, 1999, (as documented in NRC meeting summary dated March 19, 1999) for NRC Question No. 4.3.9. Among the bases for the non-plausibility findings are the following:

- SCC (various components): non-susceptible material (alloy steel or nickel-based stainless steel), lack of high tensile stresses, and a benign operating environment.
- Corrosion (various components): resistant material (austenitic stainless steel, alloy steel, and nickel-based alloys) and a benign operating environment.
- Neutron embrittlement (core support barrel upper flange): component is located above the nozzles and hence the neutron fluence is very low.
- Stress relaxation (fuel alignment pin): the damage mechanism would not affect the intended function of the component.
- Wear (CEA shrouds): no relative motion between adjacent surfaces.
- Pitting/crevice corrosion (various components): impurities that cause pitting and crevice corrosion are eliminated because of water chemistry control during operation and there were no long outages without proper water chemistry control (NRC Question No. 4.3.16).

  The staff has reviewed the bases for non-plausible aging effects and agrees that these aging effects do not require an aging management program for the above described components.

(3) Nickel-based RVI components

As discussed during the meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.17, the applicant indicated that all Alloy 600 or other nickel-based alloy components in the RVI are subject to replacement on a qualified life or specified time period. Such items are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(ii).

(4) Irradiation-assisted stress corrosion cracking (IASCC) and neutron embrittlement

In Section 4.3.2 of Appendix A to the LRA, the applicant found that IASCC is not plausible for CCNPP RVI. The staff requested that the applicant present the basis for that determination. As discussed in a meeting with the applicant on February 16, 1999 (NRC meeting summary dated March 19, 1999), concerning NRC Questions No. 4.3.11 and 4.3.18, the applicant indicated that it is working to develop data through industry research to determine the extent of IASCC and neutron embrittlement for RVI components in PWRs. Until these data are developed and subsequent analyses are completed, the applicant agreed to consider IASCC a plausible ARDM for the RVI. The aging management of IASCC is discussed in Section 3.2.3.2.1.C of this SER.

(5) Loss of fracture toughness for CASS RVI components

Reactor vessel internal components fabricated from CASS are subject to embrittlement (i.e., loss of fracture toughness) from synergistic influences of thermal aging and neutron irradiation. The applicant did not consider the effects of neutron irradiation on the toughness of CASS RVI components. As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.14, "RV Internals," the applicant agreed to a modified approach for managing aging effects of RVI components that the staff finds acceptable to manage both thermal aging embrittlement and neutron embrittlement. The aging management of CASS RVI components is discussed in Section 3.2.3.2.1.C of this SER.

(6) Neutron embrittlement of RPV supports

Neutron embrittlement of RPV supports was identified, and resolved, as Generic Safety Issue 15 (GSI-15). NUREG-1509 describes resolution of GSI-15. As described on page 3.15-8 of NUREG-0933 (Rev. 3), the issue was resolved with no new regulatory requirements on the basis of the staff's regulatory analysis. Furthermore, consideration of a license renewal term of 20 years did not change this conclusion. These conclusions were based on structural analyses that demonstrated the following:

- Postulating that one of four RPV supports was broken in a typical PWR, the remaining supports would carry the reactor vessel load even under safe-shutdown-earthquake (SSE) loads; and

- If all supports were assumed to be totally removed (i.e., broken), the short span of piping between the vessel and the shield wall would support the load of the vessel.

Given the preceding structural analysis results of GSI-15, and given that the RPV supports at CCNPP consist of the short column type with three supports per unit (two on the cold leg nozzle and one on the hot leg nozzle), neutron embrittlement of RPV supports does not require an aging management program at CCNPP.

(7) Void swelling of RVI components

By letters dated August 12 and September 30, 1999, the staff identified change of dimension of the RVI components due to void swelling as a potentially significant aging effect. This finding was based upon review of EPRI technical report TR-107521, which cites several sources with conflicting results on predicting the extent of possible void swelling for light water reactor conditions. One source predicts swelling as great as 14% for PWR baffle-former assemblies over a 40-year plant lifetime, whereas results from another source indicate that swelling would be less than 3% for the most highly irradiated sections of the internals at 60 years. The issue of concern to the staff is the impact of change of dimension due to void swelling on the ability of the RVI to perform their intended functions. Swelling of the RVI could potentially impact the ability to insert control element assemblies and maintain proper coolant flow distribution characteristics.

In responses dated September 28 and October 22, 1999, the applicant maintained its position that void swelling is not plausible. However, the applicant agreed to participate in industry programs to address the significance of void swelling. Should it be determined that void swelling is a significant issue in the renewal term, the applicant would develop a sufficient inspection program for management of the issue based upon the results of the industry programs. This inspection program would be performed in conjunction with the 10-year ISI program.

3.2.3.1.2 Aging Effects Caused by Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity from metal fatigue that results in the initiation and propagation of cracks in the material. The fatigue life of a component is a function of its material, the environment, and the number and magnitude of the applied cyclic loads. Fatigue was a design consideration for components in the CCNPP NSSS and, consequently, fatigue design is part of the CLB for CCNPP. The staff reviewed the information on fatigue of NSSS components in Sections 4.1 and 4.2 of Appendix A to the LRA for compliance with the provisions specified in 10 CFR 54.21(a)(3). By letters dated August 26, September 2, and November 2, 1998, the staff requested additional information from the applicant on fatigue assessment of NSSS components. The applicant responded to these requests in two letters dated November 19, 1998, and a third letter dated December 10, 1998.

In Section 4.1 of Appendix A to the LRA, the applicant addressed fatigue for the RCS. Table 4.1-3 of Appendix A to the LRA lists those devices within the CCNPP RCS for which the applicant considers fatigue plausible. These devices are subjected to cyclic thermal and mechanical loads during startup and shutdown of the facility, as well as temperature and pressure fluctuations that occur during the operation of the facility. The applicant further identified the following limiting locations and controlling transients for low-cycle fatigue:

- 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;
- Steam generator (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.

In Section 4.2 of Appendix A to the LRA, the applicant addressed fatigue for the RPV and CEDMs, including the RVLMS. The applicant determined that fatigue is plausible for the RPV, the CEDM, and the RVLMS. The applicant indicated that the limiting locations for low-cycle fatigue are the RPV outlet coolant nozzles and the RPV closure studs. The corresponding controlling transients are RCS cooldown from full power for the outlet coolant nozzles and RCS heatup for the closure studs. The applicant further indicated that all other RPV components/ subcomponents are considered to have low susceptibility to low-cycle fatigue.

The staff requested that the applicant describe the criteria used to determine that the other RPV components/subcomponents have a low susceptibility to low-cycle fatigue (NRC Question No. 4.2.20). The applicant responded that the criteria consisted of selecting the component with the highest fatigue usage. However, the applicant did not discuss the specific criteria used to determine the remaining components that have low susceptibility to low-cycle fatigue. As discussed in NRC Question No. 4.2.23, the applicant is performing a fatigue evaluation of other selected RPV components. In a meeting on February 18, 1999 (NRC meeting summary dated March 19, 1999), the applicant indicated that the selection of components to be monitored by the FMP was based on a Combustion Engineering (CE) review of selected components to determine the locations of high fatigue usage. The applicant further indicated that CE did not review all RPV and RCS components within the scope of license renewal. The staff requested that the applicant describe the scope of the CE review. In the previous SER (March 21, 1999, CCNPP SER), this was identified as the first component of Open Item 3.2.3.1.2-1 in the previous SER.

The applicant described the scope of the CE review in its July 2, 1999, response to the staff SER. According to the applicant, CE identified those systems that the UFSAR and technical specifications include for maintaining safe operations and achieving safe shutdown of the plant. For each identified system, CE identified those components with controlling fatigue usage factors. The applicant indicated that the following systems and components were not within the scope of the CE review:

- NSSS sampling system
- pressurizer safety valves
- power-operated relief valves
- auxiliary feedwater isolation and check valves
- main feedwater isolation and check valves
- reactor coolant pumps

In addition, the CE review did not include potential stratification loadings identified in NRC Bulletins 88-08 and 88-11.

In a followup discussion, the applicant indicated that the items listed above had been identified by CE as not within the scope of its review effort. The applicant reviewed the CE report for completeness and identified also that the CEDMs and the RVLMs had not been discussed in the CE report. Because the applicant's September 28, 1999, response did not discus the RVLMs the staff requested further clarification. In an October 5, 1999 call, the applicant clarified that the RVLMs are installed in unused partial-length CEDM housings and will be evaluated together with the CEDM housings. As a result of these reviews, the applicant determined that several RCS components should be reviewed further. These items were identified as Open Item 3.2.3.1.2-1, Open Item 3.9.3.2.3-1, and Confirmatory Item 3.4.3.2.2-1. The applicant's description of the CE review process adequately addressed the first component of Open Item 3.2.3.1.2-1. The staff considers this component of Open Item 3.2.3.1.2-1 closed. The remaining three components of Open Item 3.2.3.1.2-1 were identified and closed in Section 3.2.3.2.2 of this SER.

Section 4.3 of Appendix A to the LRA addresses fatigue for the RVI. The applicant indicated that plant transients apply cyclical thermal loadings that contribute to low-cycle fatigue accumulation of the RVI. According to the applicant, the CCNPP RVI was designed before the explicit ASME Code fatigue design requirements were developed. The applicant relied on data from other PWR plants to determine the most fatigue-sensitive RVI components. These components are identified in Table 4.3-2 of Appendix A to the LRA. The applicant indicated that these components require further evaluation. In addition, the applicant indicated that the control element assembly shroud and bolts (CEASB) are susceptible to high-cycle fatigue from flow-induced vibration. The staff agrees that the potential for high-cycle fatigue of these components needs further evaluation. For further discussion of this issue, see Section 3.2.3.2.2 of this SER.

3.2.3.1.3 Aging Effects Caused by Wear and Stress Relaxation

In Section 4.1 of Appendix A to the LRA , the applicant addresses wear for RCS components. Table 4.1-3 of the application lists those devices within the CCNPP RCS for which the applicant considers wear plausible. Wear results from the relative motion between surfaces as a result of vibratory or sliding motions. According to the applicant, wear 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 and flanges), or in clamped joints where relative motion is not intended but occurs because of loss of clamping force (e.g., tubes in supports, valve stems in seats, springs against tubes). In addition, the applicant indicated that wear can also occur between closures/closure cover plates and by flow-induced vibrations causing rubbing action between components. However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration.

In Section 4.2 of the Appendix A to the LRA, the applicant addressed wear for the RPV, RVLMS, and CEDMs. According to the applicant, components such as the RPV closure head studs, nuts, washers, the ICI tube nozzle flanges, studs, and nuts; and some internal components are susceptible to mechanical wear from relative motion between components.

In Section 4.3, "RVIs System," of Appendix A to the LRA, the applicant identified wear and stress relaxation as ARDMs that require an AMR and AMPs for certain RVIs device types to ensure plant safety during the period of extended plant operation. The device types for which a wear ARDM is considered plausible and subject to an AMR and AMPs are the CEA shroud extension shaft guides, core support barrel (CSB) upper flange, CSB alignment key, core plate fuel alignment pins, fuel alignment plate guide lug inserts, hold-down ring (HDR), and upper guide structure support plate. The device types for which a stress relaxation ARDM is considered plausible and subject to an AMR and AMPs are the CEA shroud bolts and the core shroud tie rods.

RVIs are subject to flow-induced vibration during plant operation and differential thermal expansion and contraction movement during plant heatup, cooldown, and changes in power operating cycles. The flow-induced vibration and thermal expansion and contraction cause repetitive relative movement between certain RVIs interfacing and mating surfaces. The relative movement between the interfacing and mating surfaces results in surface wear. The severity of the wear depends upon the frequency and duration of the motion and the loads imposed on the affected surfaces. The device types identified to be subject to age related wear degradation mechanisms are typical of RVI construction items found in locations of structural interfaces and mating surfaces that experience relative motion during plant operation.

The LRA RVI technical report (CE NPSD-1103) indicates that stress relaxation is a potential ARDM for the CEA shroud bolts and core shroud tie rods. The bolts and tie rods are preloaded to maintain positive contact between RVI components during plant operating conditions. Stress relaxation results from a condition of constant strain at a level close to the elastic limit for certain materials when they are exposed to elevated temperatures or neutron irradiation or both. The CEA shroud bolts are made from Alloy A-286 material and are located in the hot outlet fluid directly above the fuel. This type of bolting material has failed in RVI in other PWR plants. The core shroud tie rods are located within the RVI core barrel and adjacent to the core. Stress relaxation of the tie rods may result in a non-design condition that produces loss of preload and loss of loaded contact between mating RVI surfaces. The loss of loaded surface contact leads to loose components; thus lowering their structural resistance to fluid-induced vibration, and causes subsequent degradation of the component function.

The identification of wear and stress relaxation as a plausible ARDM affecting RVI device types is consistent with previously reported findings discussed in the nuclear plant reliability data system (NPRDS), licensee event reports (LERs), NRC GLs, NRC information notices, and industry literature.

3.2.3.2 Aging Management Programs

The staff focused its evaluation of the applicant's AMPs on the program elements rather than on the details of specific plant procedures. To determine whether the AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The LRA indicates that the corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMP. The staff's evaluation of the applicant's corrective actions program is discussed separately in Section 3.1.5 of this SER. Thus, the staff finds that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about the AMPs discussed in Section 4.1 of Appendix A to the LRA regarding the applicant's demonstration that the effects of aging from various ARDMS will be adequately managed so that the intended function of the RCS will be maintained consistent with the CLB for the period of extended operation.

3.2.3.2.1 Programs to Manage Aging Effects From Material Degradation

A. Steam Generators

For the steam generators, the applicant cited the following AMPs: (1) CP-204 and CP-217; (2) STP-M-574-1/2, "Eddy Current Exam of CCNPP Unit 1/2 SGs"; (3) MN-3-110, "Inservice Inspection of ASME Section XI Components"; (4) MN-3-301, "Boric Acid Corrosion Inspection

Program"; and (5) SG-20, "SG Primary Manway Cover Removal and Installation." The staff's evaluation of these programs follows.

(1) Chemistry Programs (CP-204 and CP-217)

The applicant submitted a description of its chemistry control programs: CP-204, "Specification and Surveillance Primary Systems" and CP-217, "Specifications and Surveillance: Secondary Chemistry." The staff's review of the applicant's chemistry programs is discussed in detail in Section 3.1.2 of this SER. The staff concludes that the applicant submitted enough information in its LRA to show that CP-204 and CP-217 are effective AMPs to manage, in part, denting, pitting, and SCC of the steam generator tubes.

(2) Eddy Current Examination of Steam Generator Tubes (STP-M-574-1/2)

The applicant described how it applies eddy current test procedure STP-M-574-1/2, "Eddy Current Examination of CCNPP 1/2 SGs" to detect and repair aging effects associated with denting, pitting, and various other forms of SCC of the steam generator tubes.

<u>Program Scope</u>

In accordance with ASME Section XI requirements and its Technical Specifications (TS), the applicant inspects the CCNPP-1 and CCNPP-2 steam generator tubes during each unit's refueling outage. STP-M-574-1/2 selects the number of steam generator tubes, sleeves, and plugs to be examined according to the applicant's TS and Electric Power Research Institute's (EPRI's) steam generator guidelines. The applicant's sampling size and expansion criteria meet, at a minimum, its TS requirements. In practice, the applicant usually exceeds the requirements in the TS because the EPRI guidelines are more comprehensive. The staff considers the scope of the applicant's inspection program acceptable because it meets both the applicant's TS and current industry guidelines, which the staff finds adequate to detect steam generator tube degradation.

<u>Preventive Actions</u>

There are no preventive or mitigative actions associated with this test procedure, and the staff did not identify it needed any.

<u>Parameters Monitored</u>

The applicant applies eddy current testing to detect aging effects on the steam generator tubes, sleeves, and plugs. In addition, the applicant applies visual techniques to those plug types not accessible for eddy current testing. In its application of eddy current techniques, the applicant follows EPRI's "PWR Steam Generator Examination Guidelines" with respect to technique and analyst qualifications. These guidelines provide, among other things, criteria for the qualification of personnel, specific techniques, and associated acquisition and data analysis (including the procedure, probe selection, analysis protocol, and reporting criteria). The EPRI guidelines direct the applicant to perform the appropriate type of eddy current test technique depending on the region of the steam generator (e.g., U-bend, top of the tubesheet, freespan) and whether the tube is sleeved or plugged. The staff considers the parameters monitored acceptable in that operating experience has demonstrated that eddy current and visual test techniques, when applied in accordance with the EPRI guidelines, provide reasonable assurance that denting, wear, pitting, and SCC in steam generator tubes, sleeves, and plugs will be detected.

Detection of Aging Effects

As presented above, the applicant described an acceptable scope, inspection frequency, and test technique to detect aging effects in steam generator tubes, sleeves, and plugs. Industry and CCNPP experience to date indicate that the applicant performs eddy current testing in a manner expected to ensure continued tube integrity in that aging effects will be discovered and repaired before there is a loss of intended function.

Monitoring and Trending

The applicant monitors tube degradation from cycle to cycle as part of its aging management program. The condition monitoring program applied at CCNPP uses inspection results to ensure that the steam generator tube integrity has been maintained over the past operating cycle. The applicant also considers the inspection findings in its operational assessment for the upcoming cycle to ensure that the tubes will perform their intended function.

Acceptance Criteria

The applicant categorizes tube degradation in accordance with its TS. Eddy current test indications sized at less than 20 percent of the nominal wall thickness are considered "imperfections," and a tube with such imperfections need not be repaired. Tubes with eddy current test indications sized at greater than or equal to 20 percent of the nominal wall thickness but less than the plugging or repair limit are considered "degraded and may remain in service." Tubes with eddy current test indications sized at greater than the plugging or repair limit are considered "defective," and must be plugged or repaired. The applicant also considers defective any tube that does not permit the passage of the eddy current test inspection probe (because the tube cannot be inspected) and any tube with a crack like indication (because it cannot be depth sized).

The applicant defines its plugging or repair limits in its TS. For tubes, eddy current indications sized, or expected to be sized before the next inspection, at greater than or equal to 40 percent of the original nominal tube wall thickness, are considered defective. For tubes that have been repaired by sleeving, the sleeves themselves are subject to repair limits of 40 percent and 28 percent of the sleeve wall thickness for Westinghouse laser-welded sleeves and ABB-Combustion Engineering tungsten-inert-gas-welded sleeves, respectively. The applicant plugs or repairs all tubes that are considered defective at the time of the inspection or that are considered to become defective before the next tube inspection. For each defective tube, the applicant prepares an IR to plug or sleeve the defective tube. The staff considers the applicant's acceptance criteria acceptable because they are based on the applicant's TS which are in turn based on ASME criteria that the staff endorses.

Operating Experience

The applicant participates in industry-sponsored initiatives related to steam generator tube degradation. The applicant demonstrated that it had incorporated industry and site-specific experience in its comprehensive inspection scope, application of enhanced eddy current techniques, and improved analyst qualifications. The applicant demonstrated that it monitors tube degradation at CCNPP through repeated tube pulls.

The staff noted in its previous SER that the applicant did not cite its TS limits on steam generator leakage, which provide for defense in depth related to the detection of degradation in the steam generator tubes. Industry experience with steam generator tube degradation indicates that eddy current test inspections may not always be adequate to detect degradation before there is a loss of intended function. The staff considers the applicant's TS limit of SG leakage adequate and the TS limit to be a necessary component of its AMP for steam generator tubes. The applicant did not credit its TS limits in its discussion of aging management for SG tubes; thus, the staff identified this issue as Open Item 3.2.3.2.1-1.

In its response dated July 2, 1999, the applicant clarified that it does not credit its TS in SG tube aging management. Instead, the applicant credits surveillance test procedure STP-O-27-1/2, "Reactor Coolant System Leakage Evaluation." This procedure provides for the determination of the amount and potential source of RCS leakage. Any abnormal RCS leakage would be detected and actions taken to correct the leakage preceeding a loss of intended function. This test procedure is performed daily and in conjunction with other plant procedures to determine RCS leakage rates. The acceptance criteria for the RCS leakage rates are provided by the TS. The applicant presented operating experience relative to the test procedure that supports its attributes. The applicant has shut down the plant on several occasions in response to RCS leakage associated with the reactor coolant pumps. The leakage was discovered by this surveillance test procedure. The staff finds the use of this program an appropriate response to the open item because it provides for defense in depth in the management of steam generator tube aging effects in that RCS leakage will be promptly identified and corrective actions taken as required by the applicant's TS. The staff considers Open Item 3.2.3.2.1-1 closed.

The staff concludes that test procedure STP-M-574-1/2, in conjunction with surveillance test procedure STP-O-27-1/2 serves as effective AMPs for the steam generator's aging effects associated with denting, wear, pitting, and the various forms of SCC (including IGSCC, IGA, and PWSCC).

(3) MN-3-110, "Inservice Inspection of ASME Section XI Components

To manage the aging effects from erosion/corrosion of the main steam outlet nozzles, the applicant relies on MN-3-110, "Inservice Inspection of ASME Section XI Components."

Program Scope

The ISI program has within its scope an inspection process (i.e., examination technique and acceptance criteria) specifically for the main steam outlet nozzles. The staff finds the scope of the ISI program adequate in that it applies directly to the main steam outlet nozzles.

Preventive Actions

There are no preventive or mitigative actions associated with the ISI program, nor did the staff report it needed one.

Parameters Monitored

The staff finds the parameters inspected acceptable because wall loss is detectable by visual techniques (for internal inspections), and ultrasonic techniques (for external inspections) are effective in detecting loss of material caused by erosion/corrosion.

Detection of Aging Effects

In a letter dated November 18, 1998, the staff requested that the applicant provide the inspection frequency for the main steam nozzle ISI inspections. The applicant replied that the inspections were scheduled in accordance with ASME Section XI, which the staff finds appropriate because it is based on the ASME Code that the staff endorses. Three inspections have been performed to date with no identification of erosion/corrosion. The staff finds that detection of aging effects before there is a loss of intended function can reasonably be expected from the ISI program because of the adequate inspection scope, technique, and frequency. Satisfactory operating experience to date also supports this conclusion.

Monitoring and Trending

There are no monitoring or trending aspects to the ISI program and the staff did not conclude it needed any.

Acceptance Criteria

The applicant stated that any deviation from nominal wall thickness or any unusual variations in wall thickness would cause it to implement its corrective action process. The staff finds this acceptable because essentially any indication of wall thinning would require the applicant to take corrective actions.

Operating Experience

The applicant has performed three inspections to date and reported no indications of erosion/corrosion of the main steam outlet nozzles.

The staff concludes that the applicant submitted enough information in its LRA to show that the ISI program is an effective aging management program for erosion/corrosion of the main steam outlet nozzles.

(4) MN-3-301, "Boric Acid Corrosion Inspection Program"

To manage general corrosion of the external surfaces of various carbon and alloy steel steam generator components potentially exposed to concentrated boric acid, the applicant credited its boric acid corrosion inspection (BACI) program. The staff discusses its review of the BACI program in detail in Section 3.1.4 of this SER. The staff concludes that the applicant provided enough information in its LRA to show that the BACI program is an effective AMP to manage general corrosion of the external surfaces of the carbon and alloy steel steam generator components.

(5) EN-4-106, "Steam Generator Tube Surveillance Program"

In response to Open Item 3.2.3.1.1-1 in the previous SER, the applicant provided additional information about a program credited with managing aging effects caused by erosion/corrosion. As stated in its July 2, 1999, letter, the applicant considers erosion/corrosion of the steam generator carbon steel eggcrate supports to be a plausible aging mechanism. To manage this mechanism, the applicant credited administrative procedure EN-4-106, "Steam Generator Tube Surveillance Program."

Program Scope

The staff finds the scope of the program acceptable because it provides specific reference to the inspection of the steam generator eggcrate supports. The applicant focuses the inspection on the periphery of the tube bundle, which is appropriate because that is the most susceptible location based on industry experience to date. With respect to inspection scope, the applicant did not provide detailed information other than to state it performs remote visual inspections of the eggcrate supports along the periphery of the tube bundle. Although the applicant did not provide explicit information in its July 2, 1999, response to the previous SER (SER dated March 21, 1999), the staff obtained more detailed information from the applicant as documented in NRC letter dated May 19, 1999, that the applicant performs inspections in both steam generators, in several locations along the periphery on both the hot-leg and cold-leg sides of each steam generator and also inspects along the length of the tube bundle. On the basis of this information the staff finds the scope of the inspection acceptable because it provides comprehensive coverage of both steam generators and focuses the eggcrate inspection in the most likely location for degradation to occur.

Preventive Actions

The applicant did not identify any preventive or mitigative actions associated with this program as it pertains specifically to erosion/corrosion of the eggcrate supports, and the staff did not conclude any were needed.

Parameters Inspected/Monitored

The applicant performs remote visual inspections of the eggcrate supports. The staff considers visual inspections adequate to detect erosion/corrosion because the effects of erosion/corrosion (i.e., material loss) are easily identifiable with visual inspections.

Detection of Aging Effects

The applicant inspected the Unit 1 steam generators during the 1996 and 1998 refueling outages and found no indications of erosion/corrosion. The applicant does not plan future inspections of the Unit 1 steam generator carbon steel eggcrate supports. The current Unit 1 steam generators are being replaced in the 2002 refueling outage with steam generators with stainless steel eggcrate supports that are significantly more resistant to erosion/corrosion.

The applicant inspected the Unit 2 steam generators during the 1999 refueling outage. The applicant found marginal, localized erosion/corrosion of the eggcrates supports on the periphery of the tube bundle. The next inspection of the Unit 2 steam generators is scheduled to take place during the next refueling outage in 2001. The applicant does not plan to perform additional inspections after the 2001 outage. During the subsequent refueling outage in 2003, the Unit 2 steam generators are scheduled to be replaced with steam generators with stainless steel eggcrate supports that are significantly more resistant to erosion/corrosion.

The staff finds the inspection frequency reasonable based on inspection results to date that indicate erosion/corrosion is not occurring in the Unit 1 steam generators and is occurring to only a minor extent in the Unit 2 steam generators. Because of the adequate inspection scope, inspection technique, and inspection frequency, the staff concludes the steam generator tube surveillance program provides reasonable assurance that aging effects caused by erosion/corrosion of the eggcrate supports will be detected before there is a loss of intended function.

Acceptance Criteria

The applicant performs remote visual inspections of the lattice bars and grades the condition of the eggcrate supports, based on the approximate amount of material loss, into one of four categories. The need for tube plugging is based on the number of eggcrate supports adversely affected, their location, and the severity of the material loss. Another licensee similarly affected by erosion/corrosion of the eggcrate supports used this approach. The staff finds the acceptance criteria acceptable because the criteria are based directly on the amount of material loss observed, have been used in the past by other licensees similarly affected by erosion/corrosion of the eggcrate supports, and can be applied to ensure that design and accident loadings on the steam generator remain within acceptable limits.

Operating Experience

Severe tube bundle fouling was considered a major factor in causing erosion/corrosion of carbon steel eggcrate supports at another domestic PWR facility. The iron transport rates for Unit 1 support the assumption of minor tube bundle fouling, and the rates for Unit 2 indicate more severe loading. The CCNPP Unit 1 inspection results indicated no erosion/corrosion of the eggcrate supports. The CCNPP Unit 2 inspection results indicated minor amounts of erosion/corrosion of the supports. All tubes in the Unit 2 steam generators potentially affected by eroded eggcrate supports remain adequately supported for both design and accident loadings. The applicant has taken steps to minimize the effects of erosion/corrosion. It chemically cleaned the Unit 2 steam generators to remove deposits from the tube bundle and also enhanced the secondary side water chemistry to reduce the susceptibility of the Unit 2 steam generators to erosion/corrosion. The staff concludes the applicant's operating experience to date supports the use of this program to manage erosion/corrosion of the steam generator tube eggcrate supports.

On the basis of the acceptability of the steam generator tube surveillance program, the staff considers Open Item 3.2.3.1.1-1 closed.

B. Pressurizer and Other RCS Components

For the pressurizers and other RCS components, the applicant cited the following AMPs: (1) MN-3-301, "Boric Acid Corrosion Inspection Program," (2) Alloy 600 program, (3) MN-3-110, "Inservice Inspection of ASME Section XI Components," (4) CP-206, "Specifications and Surveillance for Component Cooling/Service Water System" and CP-204, "Specification and Surveillance Primary Systems," (5) RV-78, "Reactor Vessel

Flange Protection Ring Removal and Closure Head Installation," and (6) CASS Evaluation Program. The staff's evaluation of these programs follows.

(1) MN-3-301, "Boric Acid Corrosion Inspection Program"

To manage the effects of general corrosion of the external surfaces of the carbon and alloy steel components from the potential exposure to concentrated boric acid, the applicant cited its BACI program. The applicant also credits this program with managing, in part, aging effects associated with wear, erosion, and SCC. The staff's review of the BACI program is discussed in detail in Section 3.1.4 of this SER.

(2) Alloy 600 Program

To manage the effects of SCC of various pressurizer components, the applicant cited its Alloy 600 program. The Alloy 600 program manages PWSCC for those pressure boundary components in the RCS fabricated from Alloy 600 steel and exposed to the RCS environment.

Program Scope

The scope of the program to date includes pressure boundary components because of larger stresses and greater potential to initiate design-basis events. The applicant excluded Alloy 600 steam generator tubes from the scope of the Alloy 600 program; management of aging effects for the steam generator tubes is discussed in Section 3.2.3.2.1 of this SER. The staff finds the scope of the Alloy 600 program acceptable for Alloy 600 pressurizer components because the program considers the most susceptible and the most safety-significant components. The applicant stated that the scope of the Alloy 600 program will be expanded to consider all Alloy 600 components and Alloy 600 weld metal (Inco 82/182).

Preventive Actions

The staff finds the preventive actions encompassed within the Alloy 600 program (e.g., nickel-plating, replacement with thermally treated Alloy 690) acceptable because the techniques described have been demonstrated by industry experience and published laboratory experience to prevent PWSCC of Alloy 600.

Parameters Inspected/Monitored

All Alloy 600 nozzles are examined at least every 24 months. The inspections are conducted under the BACI program (see Section 3.1.4 of this SER). The inspections generally consist of VT-1 and VT-2 examinations (see ASME Section XI, IWA-2211 and IWA-2212) to detect evidence of leakage by viewing each penetration region for boric acid deposits. All nondestructive examination (NDE) personnel performing examinations of Alloy

600 penetrations are qualified and certified in accordance with ASME Section XI requirements. NDE personnel are certified at a minimum as Level II, in the applicable technique, and all findings are reviewed by a Level III examiner in the applicable technique. The applicant also credits actions taken to ensure compliance with its TS limits on leakage to detect leakage that develops between refueling outages.

Upon detection of leakage, the applicant performs more extensive examinations. For example, after detecting through visual inspections leakage on the Unit 2 pressurizer heater sleeves in 1989, the applicant used a combination of visual techniques, dye penetrant techniques, and eddy current techniques. The applicant detected indications through at least one of these techniques in 23 of the 28 possibly leaking heater sleeves. (The applicant subsequently repaired 100 percent of the penetrations.) The staff finds regular, periodic walkdowns, supplemented by more intensive NDE techniques may be relied on to detect PWSCC. This finding is also supported by operating experience to date.

The predictive element of the Alloy 600 program contains a relative ranking of the most susceptible Alloy 600 components based on stress (residual and operating stresses), operating temperature, operating time, and material heat treatment. For most of those components, the applicant has already repaired or replaced the Alloy 600 penetrations. For four Unit 1 pressurizer vapor space instrument nozzles located on the pressurizer upper head, the applicant's Alloy 600 program predicts high susceptibility based on the high operating temperature of these nozzles, the number of operating hours, and an industry history of PWSCC in the pressurizer vapor space nozzles. The applicant scheduled repair or replacement of these nozzles during the year 2000 refueling outage. The applicant stated that the schedule for this replacement is intended to precede the predicted time of the first of these nozzles developing a throughwall crack. For the remaining Alloy 600 components, the applicant stated that the Alloy 600 program does not predict PWSCC to be an issue for the period of extended operation. The applicant plans to continue its periodic visual inspections to verify this prediction.

<u>Detection of Aging Effects</u>

The staff expects that aging effects can be detected before there is a loss of intended function. This expectation is based on operating experience to date, and through a combination of engineering evaluations (to predict PWSCC) and periodic visual inspections (to confirm valid predictions) as described in the Alloy 600 program, which are discussed in more detail in the preceding section, "Parameters Inspected/Monitored."

<u>Monitoring and Trending</u>

The staff finds that the applicant's plans to continually monitor pressurizer and RCS Alloy 600 components and incorporate ongoing industry experience into the Alloy 600 program will ensure that the program, particularly the susceptibility factors and models for predicting

SCC, will be continuously updated and improved upon. To illustrate, the applicant plans to update its Alloy 600 program in response to the recent 1998 leak in the upper level tap on the Unit 2 pressurizer. Before this event, PWSCC of weld metal had been identified in the laboratory, but was expected to lag behind the cracking of the wrought material connected to it. Accordingly, the Alloy 600 program plan concluded that weld metal was of low susceptibility, and all wrought Alloy 600 would lead all weld metal in time to cracking. As part of an Alloy 600 nozzle repair in the early 1990s, an Alloy 690 nozzle was welded into the RCS using Alloy 600-type weld metal. As part of the BACI program inspections, the applicant discovered a leak of the nozzle repair caused by PWSCC of the alloy weld metal. The applicant plans to revise the Alloy 600 program to reevaluate the susceptibility of Alloy 600 weld metal, including scheduling for augmented inspection, replacement, or preventive repair, as appropriate.

Acceptance Criteria

The staff finds the applicant's acceptance criteria acceptable because the applicant indicated that all evidence of leakage discovered through the inspections is evaluated.

Operating Experience

The applicant demonstrated successful implementation of its Alloy 600 program. The applicant provided plant-specific operating experience relative to PWSCC of its pressurizer heater nozzles and instrument nozzles. Visual inspections performed under the BACI program appear, at this time, to be sufficient for timely detection of PWSCC. The Alloy 600 program provided the repair/replacement options used by the applicant in its generally successful repair of the pressurizer heater and instrument nozzles. All nozzle replacements will use Alloy 690 thermally treated material or other SCC-resistant material. Welds exposed to the RCS environment will use Alloy 690-type weld fillers or other SCC-resistant materials. The Alloy 600 program contains a relative ranking of the most susceptible Alloy 600 components based on stress (residual and operating stresses), operating temperature, operating time, and material heat treatment. The rankings indicated that the Unit 2 pressurizer heater sleeves were the most susceptible among the partial penetration welded RCS or RPV penetrations due to their relatively high yield strength for Alloy 600, relatively high operating temperature (650 °F), and a reaming operation carried out before welding that cold-worked the inner diameter of the sleeve. Because of PWSCC, the applicant replaced the Unit 2 heater sleeves in 1989–1990 with thermally treated Alloy 690 heater sleeves. These sleeves are in operation and are performing their intended leak-tight function. This experience indicates that the models contained in the Alloy 600 program appear reasonably accurate.

The staff concludes that the applicant submitted enough information in its LRA to show that the Alloy 600 program is an effective AMP. The staff notes that the review of the applicant's responses to GL 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other

Closure Head Penetration Nozzles" is not complete. In addition, there exists a generic technical issue relative to PWSCC of Alloy 600 components. These issues are not being considered in the context of license renewal but resolution of these two items may result in the identification of additional issues related to the applicant's Alloy 600 program.

(3) MN-3-110, "Inservice Inspection of ASME Section XI Components"

The applicant is using MN-3-110 , which includes procedures implementing ASME Section XI requirements, to manage general corrosion on RCS components. The ISI requirements in ASME Section XI cited in the LRA provide for visual examination of accessible surfaces of RCS components. The applicant is also using MN-3-110 to manage the aging effects due to erosion of the CASS RCP case and cover; general/galvanic corrosion, and SCC of RCS components. The staff finds this program acceptable because (a) the scope of the program addresses components that could be exposed to boric acid on external surfaces, (b) this program monitors the effects of corrosion on the intended functions by detecting degradation by visual inspection, (c) the type, extent, and schedule of inspections ensure detection of degradation before loss of intended function, (d) the inspection schedule of ASME Section XI should provide for timely detection of corrosion, and (e) operating experience has shown that ASME XI requirements are historically effective.

(4) Chemistry Programs CP-206, "Specifications and Surveillance for Component Cooling/Service Water System," and CP-204, "Specification and Surveillance Primary Systems"

To manage the aging effects from IGA of the RCP seal water heat exchangers as well as various forms of SCC of RCS components, the applicant cited its chemistry control programs. The staff's review of the applicant's chemistry programs is discussed in detail in Section 3.1.2 of this SER. The staff concludes that the applicant submitted enough information in its LRA to show that CP-204 and CP-206 are effective AMPs to manage IGA and SCC of RCS components.

(5) RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation"

To manage aging effects associated with SCC of the RPV head closure seal leakage detection line, the applicant relies on technical procedure RV-78, "Reactor Vessel Flange Protection Ring Removal and Closure Head Installation."

The staff finds the scope acceptable in that it specifically identifies the component subject to the procedure (the head seal leakage detection line). The preventive action entails blowing the line clear of fluid with compressed air. Clearing the line of fluid should reduce the potential for SCC by removing the environment needed for this ARDM to be active. Therefore, the staff finds this action acceptable. Parameters monitored are nicks, scratches, and pitting; the frequency is after each refueling outage. The acceptance criteria cited are to blow the line clear of potential contaminants. The staff finds this program acceptable as a mitigation program. However, in view of the SCC that may be experienced by this line, the potential for the line to refill if the seal leaks, and the safety consequences of a leak (a small-break loss of coolant accident), the applicant needs to have an AMP that is not merely mitigative. This was identified as Open Item 3.2.3.2.1-2.

In response to Open Item 3.2.3.2.1-2 BGE letter (dated October 22, 1999), the applicant provided additional information concerning the RPV head closure seal leakage detection line. Noting that the line in each unit was replaced due to transgranular SCC, the applicant indicated that each line has an orifice in the RV flange to limit flow rate from a break in the line to less than normal RCS makeup capacity, permitting the lines to be downgraded from RCS pressure boundary to B31.7 Class II. Therefore, the consequences of failure of this line are minimized, and the staff considers Open Item 3.2.3.2.1-2 to be closed.

(6) CASS Evaluation Program

To manage aging effects associated with thermal aging embrittlement of CASS RCS components, the applicant relies on a new program titled "CASS Evaluation Program." The scope of this program encompasses all cast austenitic stainless steel components. The CASS evaluation program contains screening criteria (based upon the material delta ferrite and molybdenum contents, and method of casting) to determine susceptibility to thermal aging embrittlement. For materials found to be susceptible, an AMP is required.

The technical bases for the CASS program are contained in EPRI Technical Report 106092, Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems." The report describes screening criteria as a function of casting method, molybdenum content, and percent ferrite. Components that have percentage ferrite below the screening criteria have adequate fracture toughness and do not require inspection. Components that have percentage ferrite exceeding the screening criteria may not have adequate fracture toughness, as a result of thermal aging embrittlement, and do require augmented aging management.

In Section 4.3.2 of Appendix A to the LRA, the applicant indicates that thermal aging embrittlement is potentially significant for CASS components that exceed the following criteria:

- Centrifugally cast parts with a delta ferrite content above 20 percent;
- Statically cast components with a molybdenum content meeting the requirements of SA-351 Grades CF3 and CF8 and with a delta ferrite content above 20 percent; and

- Statically cast parts with a molybdenum content exceeding the requirements of SA-351 Grades CF3 and CF8 and with a delta ferrite content above 14 percent.

During a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.14 "Piping and Valve Bodies," the applicant agreed to the various revisions to the proposed CASS Evaluation Program. These revisions were identified in the previous SER as Confirmatory Item 3.2.3.2.1-1.

In response to Confirmatory Item 3.2.3.2.1-1 (dated July 2 and October 22, 1999), the applicant clarified various aspects of the CASS program. The specific revisions to the screening criteria process are:

- Statically cast components with a molybdenum content exceeding the requirements of SA-351 Grades CF3 and CF8 and a delta ferrite content exceeding 10 percent are considered susceptible.

- Niobium-containing cast stainless components are considered susceptible.

- Ferrite levels calculated through the "Delta Ferrite Calculation for CASS Components" program will use Hull's equivalent factors or a method producing an equivalent level of accuracy (±6 percent deviation between measured and calculated values).

Components which do not meet the screening criteria will be:

- Subject to an augmented inspection combined with a flaw tolerance evaluation, or,

- A full leak-before-break evaluation will be performed to prove that current inspection requirements are adequate to prevent catastrophic failure, or,

- Replaced.

If augmented inspection is selected for a particular component, the component will be inspected as if it was a pressure-retaining weld in ASME Section XI Inspection Category B-L-1 (pump casings), B-M-1 (valve bodies), or B-J (piping). If available inspection technology does not permit a volumetric examination of the component, an alternative approach similar to that described in ASME Code Case N-481 would be used to manage thermal aging embrittlement of the component.

The acceptance criteria for the augmented inspection will be determined by the applicant based upon the outcome of a flaw tolerance evaluation. An elastic-plastic fracture mechanics analysis will be performed for the component to determine the critical flaw size that is stable under all anticipated normal and accident loadings. This analysis may be component-specific, or an analysis that bounds a group of components may be referenced. The critical flaw size will be used to determine the inspection acceptance criteria. The critical flaw size minus an allowance for flaw growth during operation until the next inspection will equal the allowable flaw size. The staff agrees that an elastic-plastic fracture mechanics analysis can be used to determine critical flaw size and inspection acceptance criteria.

The fracture mechanics analysis would use fracture toughness properties based upon NUREG/CR-6177 or equivalent for non-niobium containing components with delta ferrite less than 25%. If a component contains niobium or 25% or greater delta ferrite, the actual fracture toughness properties will be determined on a case-by-case basis.

The applicant will include all susceptible components in the potential inspection population during each 10-year ISI. Based on staff experience with existing ASME Code ISI programs the staff believes that a 10-year ISI interval will be adequate for detecting flaws in CASS materials. All of the screening will be completed by the applicant such that ISI schedules for the susceptible components will be established before the beginning of the renewed license period.

With the applicant's response, the staff considers Confirmatory Item 3.2.3.2.1-1 to be closed.

(7) Other Aging Management Review

For cracking of the pressurizer shell and heads, including cladding cracking, the applicant stated that cracking was not plausible and did not require aging management. Industry experience has shown that cracking is a plausible ARDM that requires aging management, typically by inspections. Open Item 3.2.3.2.1-3 in the previous SER suggested that the applicant should propose an AMP.

Based upon prior industry experience, the staff determined that thermal fatigue is the aging degradation mechanism of concern. In response to the open item (BGE letter dated October 22, 1999), the applicant indicated that the surge nozzle at the inside radius and at the safe-end transition has the highest design cumulative usage factor (CUF) of 0.75. The next highest location internal to the pressurizer is the spray nozzle, with a CUF of 0.07. The response also indicates that ASME Section XI Inspection Category B-D requires a volumetric examination of this area (and all full penetration nozzles) once every ten years. This examination is sufficient for detecting flaws that have penetrated the cladding into the base material, providing an effective aging management program. Therefore, the staff considers Open Item 3.2.3.2.1-3 to be closed.

For the cracking of small-bore piping (i.e. smaller than four inches nominal pipe size but greater than 1 inch), the applicant initially proposed to manage the aging using the ASME Code Section XI ISI program. The staff requested that the applicant perform an augmented inspection of small-bore piping for license renewal because the licensee's small-bore piping program only examines the outside surface of the piping and because piping degraded on the inner surface might fail under design loading conditions. The staff would find a program that interrogates the inside of the piping to be acceptable. The augmented inspection should include Inconel materials; the information resulting from Information Notice 90-10 should be considered in developing the augmented inspection of Inconel materials. The applicant did not consider these activities. This was identified as Open Item 3.2.3.2.1-4.

In response to Open Item 3.2.3.2.1-4 (BGE letter dated October 22, 1999), the applicant agreed to include RCS small bore fittings and branch connections in the ARDI program, for detecting cracking mechanisms. These examinations, or representative components, will be performed prior to and no sooner than five years before the expiration of the current license term (before the end of the 40th year of operation) for each unit.

The elements of the ARDI program for small bore piping 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 required by the CLB and specification of required corrective actions; and,
- Evaluation of the need for follow-up examinations to monitor progress of any age related degradation.

Any corrective actions would be taken in accordance with the CCNPP Corrective Action Program to ensure that the components will remain capable of performing their intended function under all CLB conditions.

With this response, the staff considers Open Item 3.2.3.2.1-4 to be closed because although treated similarly to other aging management programs, ARDIs actually supplement existing aging management programs by providing additional assurance that either: (1) an ARDM need not be managed for the period of extended operation, or (2) the current aging management programs are effective in managing aging effects.

C. Reactor Pressure Vessel and RVIs

For the RPV/RVI, the applicant relies on the following AMPs: (1) RV-22, "RPV O-Ring Replacement," (2) MN-3-301, "Boric Acid Corrosion Inspection Program," (3) RV-62, "RPV, Stud, Nut, and Washer Cleaning," (4) comprehensive reactor vessel surveillance program (CRVSP), (5) MN-3-110, "Inservice Inspection of ASME Section XI Components," (6) Alloy 600 program, (7) delta ferrite calculation for CASS components, (8) SCC analysis of CEA shroud bolts, and, (9) ARDI program.

(1) RV-22, "RPV O-Ring Replacement"

To manage the effects of general corrosion on the RPV head and vessel O-ring sealing area, the applicant cited RV-22, "RPV O-Ring Replacement." This procedure provides for inspection and acceptance criteria for minor pitting, nicks, and scratches near or on the O-ring sealing area. This inspection is performed at every outage and any evidence of general corrosion would be detected. Corrective actions would be taken if any corrosion is found. The inspection and reporting requirements of this procedure provide adequate management of general corrosion of the RPV head and vessel O-ring sealing area.

(2) MN-3-301, "Boric Acid Corrosion Inspection Program"

To manage the effects of general corrosion of the external surfaces of the carbon and alloy steel components on the RPV/RVI components from the potential exposure to concentrated boric acid, the applicant relies on its BACI program. The staff's review of the BACI program is discussed in detail in Section 3.1.4 of this SER. The staff concludes that the applicant submitted enough information in its LRA to show that the BACI program is an effective AMP to manage general corrosion of the external surfaces of the carbon and alloy steel RPV/RVI components.

(3) RV-62, "RPV, Stud, Nut, and Washer Cleaning"

To manage aging effects associated with general corrosion of the RPV studs, nuts, and washers, the applicant cited technical procedure RV-62. This procedure specifies the procedural steps and materials to be used in the cleaning and inspection of the RPV studs, nuts, and washers for any damage done. This inspection is performed at every outage and any evidence of damage would be reported, and corrective actions taken. The inspection and reporting requirements of this procedure provide adequate management of this ARDM for these components.

(4) Comprehensive Reactor Vessel Surveillance Program (CRVSP)

In Section 4.2.2 of Appendix A to the LRA, the applicant indicates that the CCNPP comprehensive reactor vessel surveillance program (CRVSP) is used for management of neutron embrittlement of the reactor pressure vessel. Such management is accomplished through the irradiation and testing of metallurgical samples used to monitor the progress of neutron embrittlement as a function of neutron fluence. The CRVSP implements the requirements of Appendix H to 10 CFR Part 50 for the initial 40-year license period.

As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.2.6, the applicant identified the projected peak neutron fluence at the inside surface of the reactor vessels at 60 years (end of license renewal period) as 4.95×10^{19} n/cm^2 (Unit 1) and 5.77×10^{19} n/cm^2 (Unit 2). The applicant indicated that the current surveillance program consists of a plant-specific program in accordance with ASTM E 185, supplemental capsules, and capsules withdrawn from the McGuire plant. The plant-specific program consists of six capsules in each unit, with two capsules tested, three capsules to be tested, and one standby capsule. The current projected peak capsule fluences are 4.31×10^{19} n/cm^2 (Unit 1) and 3.88×10^{19} n/cm^2 (Unit 2). The surveillance capsule withdrawal schedule will be revised in 2003.

As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.2.6, the applicant indicated the following:

- The revised surveillance capsule withdrawal schedule will provide data at neutron fluence equal to or greater than the projected peak neutron fluence at the end of the license renewal period;
- If the last capsule is withdrawn before the 55th year, the applicant will establish reactor vessel neutron environment conditions (fluence, spectrum, temperature, and neutron flux) applicable to the surveillance data and the unit's pressure-temperature curves. If the plant operates outside of the limits established by these conditions, the applicant must inform the NRC and determine the impact of the condition on RPV integrity.
- If the last capsule is withdrawn before the 55th year, the applicant must install neutron dosimetry to permit tracking of the fluence to the RPV.

The proposed program, as the applicant agreed to modify it during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), will provide neutron irradiation surveillance data applicable to the period of extended operation. Therefore, the applicant will be able to monitor neutron irradiation during the period of extended operation, as is acceptable. Revision of the CRVSP was identified as Confirmatory Item 3.2.3.2.1-2 in the previous SER.

In its July 2, 1999, submittal, the applicant committed to revising the CRVSP, as discussed during the February 16, 1999, meeting (NRC meeting summary dated March 19, 1999). This closes Confirmatory Item 3.2.3.2.1-2.

(5) MN-3-110, "Inservice Inspection of ASME Section XI Components"

In Sections 4.2.2 and 4.3.2 of Appendix A to the LRA, the applicant cited this program for the detection and management of the effects of neutron embrittlement of specific RVI components, and general corrosion and SCC of specific RPV components. The applicant indicated that the scope of inspections of the RVI will be modified to specifically identify those RVI components that rely on this program for aging management for license renewal. The scope, detection, and acceptance criteria for this program are adequate to ensure management of the applicable ARDMs during license renewal, with some exceptions as discussed below.

As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question Nos. 4.3.11, and 4.3.18, the applicant committed to the use of enhanced VT-1 examination for management of IASCC of RVI components, and neutron embrittlement of RVI components, respectively, as part of the 10-year ISI program. Appropriate revisions to the CCNPP ISI program must be made to address the scope, methodology, detection, and acceptance criteria for these new inspections. Changes to the ISI program are discussed below for each ARDM.

For IASCC and neutron embrittlement of RVI components, the applicant is working to develop data through industry research to determine the susceptibility of RVI components to IASCC and neutron embrittlement. Until the data and analyses become available that indicate IASCC is not a potentially relevant ARDM and neutron embrittlement is not a concern, the applicant committed to perform enhanced VT-1 inspections to detect cracks (if any occur) in the components believed to be potentially most susceptible to IASCC as well as neutron embrittlement. The inspections will be performed as part of the 10-year ISI program during the license renewal term. Plant-specific justification will be provided to the NRC in the event the analyses and data support elimination of the inspection.

The items selected for enhanced VT-1 inspection are the re-entrant corners of the core shroud inside surfaces (the core shroud surface that faces the core). These corners are constructed by welding annealed Type 304 stainless steel plate. The residual stresses from welding, while limited to the low yield strength of the annealed plate, are potentially higher than at any other stainless steel location on the inside surface of the core shroud. In addition to potentially being the highest stressed location, the re-entrant corners are believed to also receive the highest fluence. This is qualitatively determined; the re-entrant corners project in toward the core, between two adjacent fuel bundles, so they receive neutron exposure from 270 degrees. Being closer to the fuel than any other stainless steel components, the core shroud plates and corners are exposed to hot-leg temperatures on one side and cold-leg temperatures on the other. Because of the close proximity to the fuel, gamma heating is also expected to be higher at these locations. Because of the combination of high stress, fluence, and temperature, the re-entrant corners of the core shroud, intended for enhanced inspection, are the most likely location for IASCC and embrittlement to occur. The staff agrees with the applicant's assessment.

For thermal aging embrittlement and neutron embrittlement of CASS RVI components, the applicant agreed to modify its approach for management of these ARDMs, as described in response to Confirmatory Item 3.2.3.2.1-1 in a letter dated October 22, 1999. This modified approach looks first at the applied loading on the subject components, specifically the CEA shrouds and the core support columns. If the maximum applied load anywhere on the component is less than approximately 5 ksi (the staff interprets approximately to mean less than 5.5 ksi) for normal and upset operation, then the effects of the embrittlement will be considered inconsequential. If the component has design basis loads greater than 5 ksi, the operating history of the component will be examined to determine if such conditions have occurred. As long as the component has not experienced an event or condition that creates a load exceeding 5 ksi, the effects of the embrittlement will be considered inconsequential for the component.

For components that cannot be screened out using this 5 ksi loading criteria, an enhanced VT-1 examination will be performed on the components, using a technique demonstrated by the applicant to be capable of resolving relevant indications. Should this demonstration be unsuccessful, then an alternative technique must be used that is capable of resolving relevant indications. The applicant also agreed to participate in industry programs to develop volumetric techniques for CASS, and will follow industry programs to evaluate the effects of neutron and thermal aging embrittlement on CASS.

Since the applicant has agreed to perform inspections of components that have not been screened out (as discussed above), the staff finds this program to be acceptable for managing thermal aging embrittlement and neutron embrittlement of CASS RVI components.

(6) Alloy 600 Program

To manage aging effects associated with SCC of Alloy 600 RPV components, the applicant relies on its Alloy 600 program, described in detail in Section 3.2.3.2.1.B of this SER . In Confirmatory Item 3.2.3.2.1-3 of the previous SER, the staff requested that the applicant provide additional information regarding PWSCC of the Alloy 600 control element drive mechanism (CEDM) nozzles. The applicant's July 2, 1999, response to the confirmatory item is discussed below:

- The staff requested that the applicant confirm that the CEDM nozzles are included in the periodic inspections via the BACI program. The applicant confirmed in its July 2, 1999 letter that the CEDM nozzles are included in the BACI program. The staff finds this satisfactory.

- The staff requested that the applicant confirm that cracking of the CEDM nozzles has been considered for a 60-year life and provide the results of the susceptibility evaluation for the CEDM nozzles relative to this time. The applicant responded in its July 2, 1999, letter that cracking of the CEDM nozzles has been considered for a 60-year life. The applicant evaluated and ranked the CCNPP CEDM nozzles following Nuclear Energy Institute's (NEI's) integrated ranking assessment for the industry. The NEI rankings are based on establishing a benchmark probability that the CEDM nozzles for a given facility would be equal (normalized) to the probability that a 75-percent throughwall crack would be detected and exist in the most PWSCC-degraded nozzle at the D.C. Cook Unit 2 facility relative to the time of the inspection of the head penetration at D.C. Cook Unit 2 in 1994. The CEDM nozzles are then ranked according to the time that this probability would be achieved relative to January 1, 1997. NEI normalized the CEDM nozzles in the industry into those predicted to achieve the benchmark probability within 5 years of January 1, 1997 (e.g., plants with nozzles that are highly susceptible to PWSCC), those predicted to achieve the probability within 5–15 years of January 17, 1997 (e.g., plants with nozzles that are moderately susceptible to PWSCC), and those predicted to achieve the probability within 15 years or more of January 17, 1997, (e.g., plants whose nozzles have a low susceptibility to PWSCC). The applicant's benchmark probability for the CCNPP CEDM nozzles is 34 percent. The applicant stated that CCNPP Unit 1 is currently predicted to reach this probability in the year 2034 and committed to perform a volumetric inspection of the CEDM nozzles sometime between 2029 and 2034. In a letter dated October 22, 1999, the applicant amended its response to Confirmatory Item 3.2.3.2.1-3 and committed to conduct volumetric inspections of the CEDM nozzles at CCNPP Unit 1 no later than the year 2029. This is consistent with the probabilistic ranking of the Unit 1 nozzles and is acceptable. CCNPP Unit 2 would not reach this probability before the end of extended life in 2036, and thus the applicant stated that no inspections beyond the visual inspections currently being performed under the BACI program are indicated at this time.

  The staff approved the probabilistic modeling of the CEDM nozzles to determine PWSCC susceptibility in a letter to NEI dated March 21, 1999. Thus, the staff finds the applicant's predictive modeling of the PWSCC susceptibility of the CCNPP CEDM nozzles reasonable and consistent with the current licensing basis for the facility. Because the predictive modeling of the PWSCC susceptibility of the CEDM nozzles will change over the years as more operating experience is obtained, the applicant will continually update its predictions. The updated predictions may change the timing of the volumetric inspections to either earlier or later in life. The updated predictions may also cause the applicant to pursue volumetric inspections of the Unit 2 CEDM nozzles. The staff understands that the exact timing of the volumetric inspections may change, and we find this appropriate to accommodate growing experience with this aging mechanism.

- The staff requested that the applicant provide operating experience from inspections of CEDM nozzles at CCNPP. The applicant responded in its July 2, 1999 letter that VT-2 inspections of the CEDM nozzles have been performed at CCNPP Unit 1 and Unit 2 during each refueling outage. No indications of boric acid leakage from pressure boundary leakage of the CEDM nozzles have been observed.

This closes Confirmatory Item 3.2.3.2.1-3.

(7) Delta Ferrite Calculation for CASS Components

To manage aging effects associated with thermal aging of CASS RVI components, the applicant cited the delta ferrite calculation for the CASS components program or, alternatively, an examination of the components that are subject to thermal aging, as outlined above in the evaluation of MN-3-110, "Inservice Inspection of ASME Section XI Components." This program is used to determine the delta ferrite content of the various CASS components to see if they meet or exceed applicant-specified limits for thermal aging. Discussion of this program is inextricably linked to the preceding discussion for the CASS evaluation program (Section 3.2.3.2.1.B.(6)). As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.14, "Piping and Valves," delta ferrite levels will be calculated using Hull's equivalent factors or a method producing an equivalent level of accuracy (±6 percent deviation between measured and calculated values).

The delta ferrite calculation is used to determine whether CASS components have adequate fracture toughness in accordance with the CASS evaluation program. These programs are adequate and are discussed in greater detail in Section 3.2.3.2.1.B(6) of this SER.

(8) SCC Analysis of CEA Shroud Bolts

To manage aging effects associated with SCC of the CEA shroud bolts, the applicant, in Section 4.3.2 of Appendix A to the LRA, described a program that would perform an analysis to determine if the applied stresses on these bolts are above or below the "critical stress" for SCC. In NRC Question No. 4.3.15, the staff requested that the applicant provide the basis and data used to establish the criteria in the evaluation to demonstrate that the A-286 CEA shroud bolts are not subject to SCC during the period of extended operation. In addition, information was requested with regard to the type of examination, extent of examination, and acceptance criteria that are applicable to A-286 CEA shroud bolts under the ARDI program. The applicant responded to the question on November 19, 1998. The response did not provide a technical basis for the criteria used to determine whether SCC is a concern with regard to the A-286 CEA shroud bolts. As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), the applicant reconsidered the function of the CEA shroud bolts and indicated that the function of the CEA shroud bolts is not safety-related and, therefore, this stress analysis program would not be implemented. This was identified as Confirmatory Item 3.2.3.2.1-4 in the previous safety evaluation.

In a response to this confirmatory item, dated October 22, 1999, the applicant described the geometry of the CEA shroud, CEA shroud bolts, and fuel alignment plate, and their relative roles in providing lateral support and alignment of the CEA shrouds. Specifically, at the lower end of each CEA shroud is a flow channel protrusion which extends 2.25 inches into the 3 inch thickness of the fuel alignment plate. These protrusions, in combination with compressive forces from the fuel assembly hold down springs and hydraulic forces imparted on the underside of the fuel alignment plate, provide the lateral support and alignment of the shrouds required under normal operation, and upset and faulted conditions. Therefore, the CEA shroud bolts are not required for the CEA shroud and fuel alignment plate functions to be performed during normal operation and design basis events. The staff agrees with this conclusion. However the boundary condition of the CEA shrouds will change if all of the bolts are considered failed. This extreme assumption may result in changes in the natural frequency of CEA shrouds and could have an effect on the CEA shroud response.

In its response to Confirmatory Item 3.2.3.2.1-4, letter dated October 22, 1999, the applicant addressed the potential for wear between the CEA shroud flow channels and the fuel alignment plate. The applicant found wear to be non-credible due to the tight radial tolerances between the CEA shroud flow channels and the precision-machined holes in the fuel alignment plate and insufficient lateral flow forces to induce relative motion between the CEA shrouds and the fuel alignment plate. The staff concurs with this assessment.

This closes Confirmatory Item 3.2.3.2.1-4.

In addition, in its response to Confirmatory Item 3.2.3.2.1-4 (BGE letter dated October 22, 1999), the applicant committed to perform an analysis to confirm that the CEA shroud bolts are not required for this extreme assumption, with this analysis to be completed not later than the end of 2002.

(9) ARDI Program

In Appendix A to the LRA, an ARDI program is planned to manage the effects of SCC of the CEA shroud bolts. During a meeting with the applicant on February 16, 1999, (NRC meeting summary dated March 19, 1999), the applicant stated that the shroud bolts do not perform a safety related function. Confirmatory Item 3.2.3.2.1-4 requested that the applicant document their finding that the CEA shroud bolts do not perform a safety function in accordance with 10 CFR 54.4. As discussed in Section 3.2.3.2.1C(8) of this SER, the applicant provided this finding in a letter dated October 22, 1999. Therefore, an ARDI is not required for aging management.

3.2.3.2.2 Programs to Manage Aging Effects From Fatigue

The applicant discussed potential options to manage the effects of low-cycle fatigue at CCNPP. One option considered by the applicant was to reduce the number and severity of thermal transients on the RCS components. The applicant indicated that this was already part of the general plant operating practice of the plant operators. The other option discussed by the applicant involves monitoring the fatigue life of the components. The applicant identified the FMP as the AMP for low-cycle fatigue of the RCS and RPV. The FMP is discussed by the applicant in several sections of the CCNPP LRA. The staff discusses the FMP in Section 3.1.1 of this SER.

FMP records and tracks the number of critical thermal and pressure transients for the RCS and the RPV. FMP also monitors and tracks low-cycle fatigue usage for the limiting locations discussed in Section 3.2.3.1.2 of the SER. According to the applicant, the FMP uses two methods to track low-cycle fatigue usage. The first method counts the number of critical transients for comparison to the analysis of record. The second method considers actual transient stresses to compute the fatigue usage. The applicant selected 11 locations at which to monitor low-cycle fatigue usage because these 11 locations represent the most bounding locations for critical thermal and pressure transients and operating cycles. In NRC Question No. 7.10, the staff requested that the applicant describe the parameters that are monitored by the FMP and describe how the monitored parameters are compared to the fatigue analysis of record. The applicant's response indicates that the FMP monitors the number of cycles of the critical transients for the majority of the locations. The number of cycles is then compared to the number assumed in the analysis of record. For some locations, the FMP monitors the actual stresses. These stresses are used to compute the fatigue usage for comparison to the design criteria.

The original design fatigue analyses of the RCS components involved calculating a cumulative usage factor (CUF) based on the cyclic loads that were projected to occur during the plant design life. The CUF represents the portion of the fatigue life of a component used up by the cyclic loads. The applicant indicated that only critical transients, discussed in the previous section of this evaluation, are monitored by the FMP. The FMP adds the fatigue usage from the monitored transients to the fatigue usage from all other transients contained in the original design fatigue analysis to obtain the current fatigue usage. The design criteria required that CUF be less than 1.0 to preclude initiation of fatigue cracks in the component. The applicant submitted the usage factors for the 11 critical RCS components through 1996. In NRC Question No. 7.12, the staff requested that the applicant submit the projected usage factors for the critical

RCS components at the end of the extended period of operation. In NRC Question No. 4.2.24, the staff requested that the applicant submit this information for the critical RPV components. The applicant submitted this information in its November 19, 1998, response. The applicant's responses indicate that the CUF is expected to be less than 1.0 at 60 years at most of the monitored locations. However, the applicant indicated that the charging inlet nozzle is expected to exceed the number of letdown transients assumed in the analysis of record. The applicant further indicated that an analysis was underway to justify an increase in the number of allowable transients. Further discussion of this issue can be found in Section 3.4 of this SER.

The applicant indicated that a one-time fatigue analysis would be performed for the RCPs, MOVs, and PRVs to determine if these components are bounded by components and transients currently included in the FMP. In NRC Question No. 7.11, the staff requested that the applicant describe the fatigue criteria used in the design of these components. The staff also requested that the applicant describe the purpose and criteria for the one-time fatigue analysis. The applicant indicated that it was evaluating these RCS components to determine whether the fatigue is bounded by other components monitored by the FMP. As discussed previously in regard to NRC Question No. 4.2.23 (see Section 3.2.3.1.2 of this SER), the applicant has not completed its evaluation of all RCS components within the scope of license renewal. The applicant should complete its evaluation of the RCS components and modify the FMP as necessary. The applicant should discuss the results of the evaluation, identify additional locations added to the FMP, and describe the controlling transients and parameters that will be monitored for the locations added to the FMP. In the previous SER, this was identified as the second component of Open Item 3.2.3.1.2-1.

By letter dated July 2, 1999, the applicant committed to performing an evaluation similar to the CE review described in Section 3.2.3.1.2 of this SER. The applicant has a formal action plan and has committed to completing the evaluation by mid-2003, with any changes to the FMP to be completed by the end of 2003. With this commitment, the staff considers the second component of Open Item 3.2.3.1.2-1 closed.

The applicant indicated that CCNPP has shut down on several occasions because of RCS leakage associated with the RCPs. The applicant indicated that a vibration monitoring program was implemented for the piping associated with RCP seal leakoff lines. In NRC Question No. 7.9, the staff requested that the applicant describe the parameters monitored by the program. The staff also requested that the applicant submit the acceptance criteria for the parameters monitored, including the technical basis for the acceptance criteria. In its response to NRC Question No. 7.9, the applicant discussed the pumps and sensing lines. However, the applicant did not discuss the seal leakoff lines. In a meeting on February 18, 1999 (NRC meeting summary dated March 19, 1999), the applicant indicated that the seal leakoff lines are not safety-related. The applicant further indicated that its discussion of these lines was only in the context of describing CCNPP plant operating experience. The staff agrees with the applicant's contention that these lines are not safety related. In it's September 28, 1999 submittal, The applicant discussed the long-term corrective actions to prevent future failures of these lines. The applicant concluded that the corrective actions, combined with continuing monitoring, will prevent future vibratory fatigue-related failures of these lines. The staff agrees with the applicant's assessment.

The applicant indicated that design fatigue analysis of the CCNPP RPVs determined the bounding locations and transients. The applicant further indicated that the FMP adds fatigue usage resulting from RCS heatup and cooldown transients to the fatigue usage computed in the initial design analysis to determine the current CUF. The staff requested that the applicant describe the parameters monitored by the FMP that are applicable to the RPV. In NRC Question No. 4.2.21, the staff also requested that the applicant describe how the monitored parameters are compared to the fatigue analysis of record. The applicant responded that the number of cooldowns for the RPV outlet nozzles and the number of heatups for the RPV closure studs are monitored and compared to the analysis of record every 6 months.

The applicant indicated that, as part of the FMP, an engineering evaluation will be performed to determine if the low-cycle fatigue usage for the CEDM/RVLMS components is bounded by existing bounding components. In NRC Question No. 4.2.23, the staff requested that the applicant describe the fatigue criteria used in the design of the CEDM/RVLMS components and indicate the reason for performing the engineering evaluation of these components. The applicant indicated that it was evaluating CEDM/RVLMS components to determine whether the fatigue is bounded by other components monitored by the FMP. The applicant has not completed its evaluation of the components associated with the RPV. The staff requested the applicant to complete its evaluation of the CEDM/RVLMS components and modify the FMP as necessary. The applicant should discuss the results of the evaluation, identify additional locations added to the FMP, and describe the controlling transients and parameters that will be monitored for the locations added to the FMP. In the previous SER, this was identified as the third component of Open Item 3.2.3.1.2-1.

By letter dated July 2, 1999, the applicant committed to performing an evaluation similar to the CE review described in Section 3.2.3.1.2 of this SER. The applicant has a formal action plan and has committed to completing the evaluation by mid-2003, with any changes to the FMP to be completed by the end of 2003. With this commitment, the staff considers the third component of Open Item 3.2.3.1.2-1 closed.

In Section 4.2 of Appendix A to the LRA, the applicant also indicated that, in conjunction with EPRI, it has initiated an additional study to evaluate the effects of low-cycle fatigue on various fatigue-critical plant locations. In NRC Question No. 4.2.25, the staff requested that the applicant describe this program and describe its applicability to the RPV and CEDM/RVLMS components. The applicant's response referenced the results of a study noted in EPRI report TR-107515. The EPRI study is discussed in Section 3.2.3.3 of this SER.

The FMP relies on sampling of critical plant transients for selected RPV and RCS components at CCNPP to manage fatigue. The staff agrees that monitoring of plant transients causing significant fatigue usage for critical components can adequately represent the fatigue usage for the remaining RPV and RCS locations. Because the applicant has committed to complete the additional evaluations described above (in this section) by letter dated July 2, 1999, the staff concludes that the applicant's FMP sampling approach is adequate to manage fatigue of the RPV and RCS components.

In Section 4.3 of Appendix A to the LRA, the applicant indicated that fatigue analyses of the fatigue-sensitive RVI components identified in Table 4.3-2 of Appendix A to the LRA would be performed. These analyses will be based on ASME Code fatigue criteria. The applicant indicated that, if the fatigue analyses demonstrate low fatigue usage (CUF<0.5), no further evaluation of the components will be performed. The applicant further committed to perform additional evaluation of those components with a CUF>0.5 in order to determine whether the component is bounded by the other components monitored by the FMP. Any RVI component not bounded by existing FMP components will be added to the FMP. The staff requested the applicant to complete its analyses of the RVI components and modify the FMP as necessary. The applicant should also discuss the results of the evaluation, identify additional locations added to the FMP, and describe the controlling transients and parameters that will be monitored for the locations added to the FMP. This was identified as the fourth component of Open Item 3.2.3.1.2-1 in the previous SER.

By letter dated July 2, 1999, the applicant committed to performing an evaluation similar to the CE review described in Section 3.2.3.1.2 of this SER. The applicant has a formal action plan and has committed to completing the evaluation by mid-2003, with any changes to the FMP to be completed by the end of 2003. With this commitment, the staff considers the fourth component of Open Item 3.2.3.1.2-1 closed.

The applicant indicated that CCNPP has not discovered any high-cycle fatigue-related failures in the RVI. The applicant further indicated that high-cycle fatigue failures normally occur early in plant life, making it highly unlikely that components subject to high-cycle fatigue loads will fail during the license renewal period. The applicant relies on the ASME Section XI inservice inspection (ISI) program to manage the effects of high-cycle fatigue for the components of the RVI. The ISI program inspections are discussed in Section 3.2.3.2.4 in this SER. The staff agrees with the applicant's assessment, that a high-cycle fatigue failure is likely to occur early in plant life because flow induced vibratory loads will produce a large number of cycles early in the plant life. Given that CCNPP has no history of high-cycle fatigue failures of the RVI components, the ISI program provides an adequate method to continue to monitor the potential for high-cycle fatigue damage of the CCNPP CEASB. The Section XI ISI program provides an acceptable means for managing high-cycle fatigue of the RVI.

3.2.3.2.3 Programs to Manage Aging Effects From Wear and Stress Relaxation

A. Reactor Pressure Vessel

The applicant stated that components in the reactor vessel are susceptible to wear caused by relative motion between them. These components, however, are visually examined under the following programs to detect the effects of wear:

- The CCNPP ISI program provides for discovery and management of the effects of wear in accordance with the requirements of the ASME Code, Section XI.
- The BACI program provides for inspection around the CEDM and RVLMS vent areas. Inspection of these areas could indicate any reactor coolant leakage and necessary replacement of vent balls due to wear.
- The CCNPP procedure RV-62 involves cleaning and inspection of the RPV studs, nuts, and washers, which supplements the visual examination performed during the ISI.
- The CCNPP procedure RV-85 involves cleaning and inspection of the ICI tube nozzle flanges, which also supplements the visual examination performed during the ISI.
- The applicant proposed to perform visual inspection of the Grayloc clamps, studs, nuts, and heated junction thermocouple (HJTC) seal plug and drive nut for wear by modifying the CCNPP procedure RVLMS-2. This will further supplement the visual examination performed during the ISI for surveillance of wear.

The staff, therefore, has determined that there is reasonable assurance that the effect of wear will be detected during visual inspection performed under the preceding programs and that the corrective actions taken as part of the program will ensure that the components remain capable of performing their intended function under CLB conditions during the period of extended operation.

B. Reactor Coolant System

The applicant identified components in the RCS that are susceptible to wear from relative motion between them. The applicant relies on the following plant procedures to examine the components susceptible to wear:

- CCNPP administrative procedure MN-3-110 provides for examination and inspection of components identified in accordance with the requirements of ASME Code, Section XI.
- CCNPP BACI program MN-3-301 provides for walkdown examinations of specific areas to detect RCS leakage.

- The applicant will continue to review industry experience with respect to wear of RCP seal water heat exchanger tubes in accordance with administrative procedure NS-1-100.
- CCNPP technical procedures STP-M-574-1/2 provide for eddy current examinations of SG tubes.

On the basis of the information received, the staff has concluded that the inspection activities and the frequency of inspections is sufficient to detect wear in the applicable RCS components in time to implement corrective actions prior to the loss of intended function(s) such that there is reasonable assurance that effects of wear on RCS components will be managed by the programs listed above and the intended functions will be adequately maintained during the extended period of operation.

The RVI technical report indicates that the applicant's ISI program is adequate for managing the aging effects of wear to ensure the structural integrity of the RVI. The ISI program constitutes the applicant's wear AMP that will continue to be used at CCNPP during the period of extended operation. The ISI program invokes the requirements of Section XI of the ASME Boiler and Pressure Vessel (B&PV) Code, 1983 Edition through Summer 1983 Addenda, that specify the ISI requirements for the RVI. The applicant defines RVI as Class 1 components in accordance with the ASME B&PV Code, Section XI, Subsection IWB. The applicant indicated that its ISI program ensures that Class 1 components are inspected as required by 10 CFR 50.55a in accordance with the ASME B&PV Code, Section XI, requirements with regard to the inspection methods and frequency, identification of the devices to be inspected, acceptance criteria, and corrective action. The applicant's RVI technical report indicates that the ISI program employs NDE methods to measure material properties and assess the condition of a component's fitness for its intended use. The program requires visual examination of RVI accessible surfaces of the core support structures that must be removed from the reactor vessel for certain examinations. The applicant's LRA indicates that wear can be discovered when the reactor vessel is opened during refueling outages, and the RVIs are subject to a visual examination of accessible surfaces. Further, the report indicates that, since wear between accessible surfaces that are 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, the ISI program is adequate to manage the aging effects of wear.

The applicant's use of visual inspection in accordance with the ASME B&PV Code for the management of the aging effects of wear is consistent with the general industry approach to managing the effects of detectable wear. However, in a letter dated September 3, 1998, the staff issued NRC Question No. 4.3.21, requesting information about the applicant's specific application of visual examination methods with regard to wear of the HDR and associated RVI wear surfaces affecting the HDR clamping capability, and the accuracy requirements involved in the use of visual wear measurements. On November 19, 1998, the applicant responded to the question. The staff found that the response did not contain all the information requested. The response did not contain a description of the accuracy of visual examinations required to provide reliable measurements to manage aging effects of wear on the HDR. The staff concluded that the applicant should discuss the accuracy of visual examinations required to provide reliable measurements of detectable wear used to assess the performance of the hold down ring in managing the aging effects of wear and considered this Open Item 3.2.3.2.4-1.

The application for license renewal, in part, indicates that (1) wear can be discovered when the reactor vessel is open and RVIs components are examined; (2) wear between accessible surfaces subject to relative motion is readily detectable by visual examination before the effects of wear begin to compromise the function of the component; and (3) examinations will be performed and appropriate corrective action will be taken if significant wear is discovered.

In the July 2, 1999 response to Open Item 3.2.3.2.4-1, the applicant stated that the visual examination technique used for the indication of wear is accurate to 1/32-inch, and this accuracy is sufficient to assess effects of wear so action may be taken before a loss of intended function occurs. Because the applicant's response provides the information needed to demonstrate that the effect of aging wear degradation is adequately managed, Open Item 3.2.3.2.4-1 is closed.

On September 3, 1998, the staff also requested a description of the inspections performed, or that will be performed with regard to changes in as-built dimensions and deflection or wear measurements that demonstrate that the RVI HDR clamping force will not be reduced so as to impair its intended function of restricting core barrel motion during the period of extended plant operations (NRC Question No. 4.3.22). In addition, the staff also requested the basis for not considering the HDR as a device type subject to stress relaxation. The applicant responded to the question on November 19, 1998. The response did not contain the information requested with regard to wear of RVI surfaces effects on the core barrel hold-down capability function and the basis for not considering the HDR subject to stress relaxation. The issue of changes in as-built dimensions and deflection or wear measurements that demonstrate that the RVI HDR clamping force will not be reduced so as to impair its intended function of restricting core barrel motion during the period of extended plant operations was covered in the meeting discussions with the applicant with regard to NRC Question No. 4.3.21, as previously described. The basis for not considering the HDR subject to stress relaxation was also discussed with the applicant's licensing representatives during a meeting at CCNPP on February 18, 1999 (NRC meeting summary dated March 19, 1999). During the meeting with the staff held at the CCNPP facilities on February 18, 1999, the applicant stated its basis for not considering a stress relaxation ARDM plausible for the hold-down ring. The staff concluded that the applicant should document the basis for not considering a stress relaxation ARDM plausible for the hold-down ring and considered this Confirmatory Item 3.2.3.2.4-1.

In the July 2, 1999, response to Confirmatory Item 3.2.3.2.4-1, the applicant indicated that the hold-down ring stress relaxation ARDM is not plausible since the radiation levels are not sufficient for this ARDM to occur. The applicant's determination is based on in-pile testing data of stainless steel materials that have shown that substantial loss of pre-load is possible at PWR operating temperatures in a high radiation field (5×10^{20} n/cm^2, E>1 MeV) when the materials are stressed at or above yield stress; and on extrapolated fluence values from a Combustion Engineering referenced memorandum, "Relaxation of 13Cr-4Ni Hold Down Ring Material," that shows that the fluence levels of the hold-down ring will be in the range of 10^{12} to 10^{13} n/cm^2 for a 60-year life. Because the applicant's response provides the requested basis to demonstrate that stress relaxation is not a plausible ARDM for the hold-down ring, Confirmatory Item 3.2.3.2.4-1 is closed.

3.2.3.3 Time-Limited Aging Analyses

The staff's evaluation of the identification of time-limiting aging analyses (TLAAs) is discussed separately in Chapter 4 of this SER.

(1) For Neutron Embrittlement of Reactor Vessel

This TLAA concerns the effect of neutron embrittlement on the fracture toughness of the reactor pressure vessel base plates and weld metals. The applicant identified the following analyses as affected by neutron embrittlement of the RPV:

- pressurized thermal shock (PTS) requirements (10 CFR 50.61)
- low-temperature overpressure protection, power-operated relief valve setpoints, and administrative controls
- plant heatup/cooldown (pressure/temperature or P/T) curves

The common aspect in each of these analyses is the reliance on the neutron fluence as a parameter to determine the fracture toughness of the RPV materials as a function of effective full power years (EFPYs). An analogous analysis is that for Charpy upper-shelf energy, as required in Appendix G to 10 CFR Part 50. Charpy upper-shelf energy should also be identified by the applicant as a TLAA. Specifically, the statements in Section 2.1.3.2 of Appendix A to the LRA, which describe determination of the (transition temperature) fracture toughness ("analyses that provide operating limits or address regulatory requirements," and "the calculations are based on periodic assessments of the neutron fluence and resultant changes") are also directly applicable to the determination of the upper-shelf toughness.

All of these TLAAs are encompassed within the current licensing basis and, as such, the licensee is always required to be in compliance with the appropriate operating limits and regulatory requirements. The applicant currently has in place a process for ensuring compliance with the appropriate operating limits and regulatory requirements. This process involves use of results from the CCNPP comprehensive reactor vessel surveillance program, the surveillance program for the McGuire plant, industry and owners group programs, and, finally, the methodology found in Regulatory Guide 1.99 (Revision 2) and the PTS rule (10

CFR 50.61). As described on page 4.2-26 of Appendix A to the LRA, the applicant will continue to make periodic adjustments to account for any new information on the RPV beltline materials.

A. Pressurized Thermal Shock Requirements

As outlined in the RVI technical report, CCNPP Units 1 and 2 are projected to be within the PTS screening criteria for 20 years beyond the current expiration dates of the licenses. This covers the period of the renewed license. As accounted for in the applicant's process for evaluating neutron embrittlement of the RPV materials, these projections are subject to change as new information and data become available. Any changes will be evaluated in accordance with 10 CFR 50.61, which requires an assessment whenever a "significant" change in the neutron embrittlement occurs. With respect to the PTS requirements, the licensee satisfies 10 CFR 54.21(c)(i) because the PTS screening criteria are satisfied for 20 years beyond the current expiration date of the license.

B. Heatup/Cooldown (Pressure/Temperature or P/T) Curves

The plant operating curves, referred to as the heatup/cooldown or pressure-temperature curves, are required in accordance with Appendix G to 10 CFR Part 50, and are determined in accordance with Appendix G to Section XI of the ASME Code. In response to NRC Question No. 4.2.8, the applicant stated that the current curves for Unit 1 remain valid for 48 EFPYs (which equates to 60 operating years). In Section 2.1.3.2 of Appendix A to the LRA, the applicant stated that the current curves for Unit 2 are valid for 30 EFPYs, and will be updated to ensure that the operating curves remain valid at the current cumulative neutron fluence level. Any changes in the P/T curves will be evaluated in accordance with Appendices G and H to 10 CFR Part 50. Appendix G requires that the effects of neutron radiation must be accounted for in determining the fracture toughness of the RPV beltline materials. Appendix H requires an evaluation of the need for changes in the pressure-temperature limits with submittal of a surveillance capsule test report. Therefore, with respect to heatup and cooldown curves, the licensee satisfies 10 CFR 54.21(c)(1)(i) for Unit 1 because the P/T limits are valid for 60 years. For Unit 2 the licensee satisfies 10 CFR 54.21(c)(1)(iii) because the P/T limits are adequate for 30 EFPYs, and will be updated to meet the requirements of Appendix G, 10 CFR Part 50 for 48 EFPYs, (60 years of operation).

C. Charpy Upper-Shelf Energy Requirements

Appendix G to 10 CFR Part 50 requires that each RPV material must maintain Charpy upper- shelf energy (USE) of at least 50 ft-lb throughout the life of the vessel. In response to NRC Question No. 4.2.5, the applicant stated that no RPV beltline material will fall below 50 ft-lb upper-shelf energy before 48 EFPYs. Appendix G to 10 CFR Part 50 requires that the effects of neutron radiation must be accounted for in determining the Charpy upper-shelf energy of the RPV beltline materials, and that the materials must exhibit at least 50 ft-lb upper-shelf energy or provide margins of safety against fracture equivalent to those required by Appendix G to Section XI of the ASME Code. Therefore, with respect to the Charpy upper-shelf energy the licensee satisfies 10 CFR 54.21(c)(1)(i) because upper-shelf energy will not fall below 50 ft-lb before 48 EFPYs.

(2) Fatigue

In Section 2.1.3.3 of Appendix A to the LRA, the applicant stated that the fatigue analyses of components of the NSSS are time-limited aging analyses (TLAAs) in accordance with the CLB. According to the applicant, the RCS components were designed in accordance with the American Society of Mechanical Engineers (ASME) B&PV Code, Section III, and the American National Standards Institute (ANSI) Standard USAS B31.7, "Nuclear Power Piping Code." As discussed previously, the CLB fatigue analysis of the RCS components involved calculating a cumulative usage factor (CUF) based on cyclic loads that are projected to occur during the plant's design life. Consequently, fatigue analysis is a TLAA for these components.

The CCNPP FMP monitors and tracks the number of critical thermal and pressure test transients, and monitors the cycles and fatigue usage for the limiting components of the NSSS. The applicant indicated that, in order to stay within the design basis, corrective actions would be initiated in advance of the design limit on fatigue usage being exceeded or the number of design cycles being exceeded. In NRC Question Nos. 4.2.22 and 7.13, the staff requested that the applicant describe the criteria used to determine when corrective actions will be initiated. Corrective actions are discussed in Section 3.1.1 of this SER.

The applicant's FMP monitors and tracks transients and cycles at selected components to ensure that these components stay within their design basis. GSI-166, "Adequacy of the Fatigue Life of Metal Components," raised concerns regarding the conservatism of the fatigue curves used in the design of these components. Although GSI-166 was resolved for the current 40-year design life of operating plants, the staff initiated GSI-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The resolution of GSI-166 for the 40-year design life relied, in part, on conservatism in the existing CLB analyses. This conservatism included the number and magnitude of the cyclic loads postulated in the initial component design. A detailed discussion of the GSI-166 evaluation is contained in SECY 95-245.

The staff assessment for GSI-166 is a basis for the current 40-year plant design life. However, the staff assessment took credit for the conservatism in the current licensing basis fatigue analyses for the 40-year plant life. The staff further indicated that its assessment could not be extrapolated beyond the current facility design life (40 years). Therefore, the GSI-166 resolution only applies to the fatigue accumulation for a 40-year design life.

The applicant's FMP tracks fatigue usage of critical components and compares the fatigue usage to the CLB criteria. GSI-166 and GSI-190 identified a concern regarding the conservatism of the CLB fatigue design curves. In SECY 95-245, the staff recommended not to backfit new fatigue criteria to current operating nuclear power plants based, in part, on an assessment of the conservatism in existing fatigue analyses of components at operating plants for the 40-year design life. The staff did recommend that a sample of components with high fatigue usage factors be evaluated for any extended period of operation.

By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two EPRI technical reports dealing with the fatigue issue. EPRI report TR-107515 was part of an industry attempt to resolve GSI-190. As recommended in SECY-95-245, EPRI analyzed components with high usage factors using environmental fatigue data. The staff has open technical concerns regarding the EPRI evaluations. These concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998.

Since GSI-190 has not been resolved, the staff requested, by letter dated November 2, 1998, that the applicant discuss how it satisfies the relevant portion of Section 54.29 of the license renewal rule as explained in the statement of considerations (SOC) (60 FR 22484, May 8, 1995) and as described in subsection 6.3.5, of Section 2.0 of Appendix A to the LRA. The applicant did not present a technical rationale addressing the adequacy of components in the reactor coolant pressure boundary considering environmental fatigue effects until GSI-190 is resolved. In a December 10, 1998, letter, the applicant stated that it only relied on the EPRI report to support its finding regarding the chemical and volume control system (CVCS). In addition, the applicant stated that the LRA demonstrates that the effects of fatigue on the CVCS will be managed in a manner that maintains the plant's current licensing basis, while GSI-190 is being resolved. The staff considers the issue raised by GSI-190 regarding environmental fatigue applicable to the RPV and the RCS, as well as to other systems, because the environmental fatigue data are also applicable to these systems. The staff identified resolution of the concern regarding environmental effects on the fatigue life of components as Confirmatory Item 3.2.3.3-1.

In its July 2, 1999, response to the staff's SER, the applicant proposed two alternatives to address GSI-190. The applicant further stated that these alternatives will be described and controlled as commitments in its FSAR. The proposed alternatives are

- Adopt NRC's eventual generic resolution of GSI-190.
- Implement a plant-specific monitoring program.

The applicant described the proposed plant-specific monitoring program in its letter. The applicant's proposed program relies on the locations currently monitored by the CCNPP FMP. According to the applicant, the effects of the reactor water environment on fatigue life of components will be incorporated in the FMP before operation during the period of extended operation. The applicant indicated that the following bounding locations would be included in the evaluation:

- charging system piping
- charging inlet nozzles
- charging inlet nozzle piping
- hot leg surge nozzle
- pressurizer spray system piping
- pressurizer spray nozzle
- pressurizer surge line
- pressurizer surge nozzle
- pressurizer surge line elbow
- SI nozzle
- shutdown cooling outlet nozzle

The staff finds that these bounding locations provide an adequate sample to monitor the effects of environment on fatigue life of components at the CCNPP.

The applicant will assess the effect of the environment using statistical correlations developed by Argonne National Laboratory (ANL) and published in NUREG/CR-5704. The applicant will use the ANL statistical correlations to calculate an effective environmental factor to account for the reduction in fatigue life due to the reactor water environment. This factor will be applied to fatigue loads where the specified threshold criteria for strain rate and temperature have been exceeded. In applying this approach, the applicant has taken some credit for moderate environmental effects in the original fatigue design curves by calculating an effective environmental factor. A discussion of the credit available in the design fatigue curves to accommodate environmental effects is contained in the attachment to the staff's November 2, 1998, letter. In that attachment, the staff indicated that a factor of less than 1.5 on life may be used to account for acceptable effects of environment for austenitic stainless steel components. The applicant proposed the factor of 1.5 for its evaluation of austenitic stainless steel components.

The staff considers the applicant's proposed program an acceptable plant-specific approach for the resolution of GSI-190. The staff concludes that the FMP, modified to account for the reactor water environment as described above, provides an acceptable method for managing fatigue for the period of extended operation and satisfies the requirements of 10 CFR 54.21(c)(1)(iii). Therefore, Confirmatory Item 3.2.3.3-1 is closed.

3.2.4 Conclusions

The staff has reviewed the information in Section 4.1, "Reactor Coolant System"; Section 4.2, "Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System"; and Section 4.3, "RVIs System," of Appendix A to the LRA and additional information sent by the applicant in response to the staff RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the RVIC systems will be adequately managed so that there is reasonable assurance that the RVIC systems will perform their intended function in accordance with the CLB during the period of extended operation.

3.3 Engineered Safety Features

3.3.1 Introduction

The applicant described its AMR of the engineered safety features (ESFs) in the following three sections of Appendix A to its LRA: Section 5.5, "Containment Isolation (CI) Group"; Section 5.6, "Containment Spray (CS) System"; and Section 5.15, "Safety Injection (SI) System." The staff reviewed these sections of the application to determine whether the licensee provided adequate information to meet the requirements of 10 CFR 54.21(a)(3) for managing the aging effects of the ESFs for license renewal.

3.3.2 Summary of Technical Information in the Application

3.3.2.1 Structures and Components Subject to an Aging Management Review

Section 5.5.1.1 of Appendix A to the LRA describes the CI group as consisting of those components with only a CI function and not evaluated for this function in other sections of Appendix A to the LRA. Figure 5.5-1 in Section 5.5 identifies the systems that are evaluated in this section of the LRA. The components in these systems that are responsible for the containment isolation function and pressure boundary system maintenance function require an AMR and are identified in Table 5.5-1 of Appendix A to the LRA. They include carbon and stainless steel piping, check valves, control valves, hand valves, motor-operated valves (MOVs), relief valves, and tanks. The staff's evaluation of this information is discussed in Sections 2.2.3.16.2.2 and 2.2.3.16.3 of this SER.

The CS system is described in Section 5.6.1.1 of Appendix A to the LRA. The major function of the CS system is to limit the pressure and temperature of the containment atmosphere so that the associated design limits are not exceeded following design-basis events. This function is performed by spraying cold borated water into the containment atmosphere. The CS system is also used to remove heat from the reactor coolant system (RCS) during plant cooldown and to maintain the RCS temperature during cold shutdown and refueling operation modes. During normal plant operations, the CS system is maintained in a standby mode. Table 5.6-1 in Section 5.6 of Appendix A to the LRA identifies the components in the CS system that are subject to an AMR. They are piping, valves, heat exchangers, the pump/driver assembly, flow elements and orifices, and temperature elements and indicators. The staff's evaluation of this information is discussed in Sections 2.2.3.17.2.2 and 2.2.3.17.3 of this SER.

The SI system is described in Section 5.15.1.1 of Appendix A to the LRA. The major functions of the SI system are to supply emergency core cooling in the unlikely event of a loss-of-coolant accident and to increase shutdown margin following the rapid cooldown of the RCS caused by a rupture of a main steamline. These functions are performed by injecting borated water into the RCS. Table 5.15-1 in Section 5.15 of Appendix A to the LRA identifies the components in the SI system that are subject to an AMR. They include piping, valves, heat exchangers, flow elements and orifices, the pump drive assembly, temperature elements and indicators, and tanks. The staff's evaluation of this information is discussed in Sections 2.2.3.28.2.2, and 2.2.3.28.3 of this SER.

3.3.2.2 Effects of Aging

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the aforementioned components that are subject to AMR. Table 5.5-2 in Appendix A to the LRA identifies crevice corrosion, general corrosion, microbiologically induced corrosion (MIC), pitting, and wear as plausible ARDMs for the CI group components. Table 5.6-2 identifies crevice corrosion, general corrosion, and pitting as plausible ARDMs for the CS system. Table 5.15-2 identifies crevice corrosion, fatigue, general corrosion, MIC, pitting, SCC, and weathering as plausible ARDMs for the SI system.

3.3.2.3 Aging Management Programs

The applicant identified the following AMPs for the ESF systems for license renewal in the application:

- CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program" (existing program—applicable to CS and SI systems and the CI group)
- CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems" (existing program—applicable to CS and SI systems)
- CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System" (existing program—applicable to CS and SI systems)
- CCNPP Technical Procedure CP-202, "Specification and Surveillances—Demineralized Water, Safety-Related Battery Water, and Well Water Systems" (existing program—applicable to the SI system)
- CCNPP Surveillance Test Procedure M-571G-1(2), "Local Leak Rate Test," Penetrations 9, 10, 23, 24, 37, and 39 (existing programs—applicable to CS and SI systems)
- CCNPP Surveillance Test Procedure M-571L-1(2), "Local Leak Rate Test," Penetration 41 (existing program—applicable to the SI system)
- CCNPP Local Leakage Rate Testing Programs STP-M-571A-1, A-2, D-1, D-2, E-1, E-2, G-1, G-2, M-1, and M-2 (existing programs—applicable to the CI group)
- CCNPP Pump and Valve Inservice Test Program (existing program—applicable to the SI system)

- CCNPP Fatigue Monitoring Program (existing program—applicable to the SI system)
- MN-1-319, "Structure and System Walkdowns" (modified program—applicable to the SI system)
- ARDI program (new program—applicable to the CS and SI systems and the CI group)

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the ESF systems would be maintained during the period of extended operation, consistent with the CLB under all design-loading conditions.

3.3.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-limited Aging Analyses," of Appendix A to the LRA indicates that there are no TLAAs applicable to any of the ESF systems.

3.3.3 Staff Evaluation

3.3.3.1 Effects of Aging

In Sections 5.5.2, 5.6.2, and 5.15.2 of Appendix A to the LRA for the CI group, the CS system, and the SI system, respectively, the applicant grouped components of similar characteristics in these systems and that require AMR into the categories described in Sections 3.3.3.1.1, 3.3.3.1.2, and 3.3.3.1.3 of this SER. The applicant evaluated the plausible ARDMs for each of these groups.

In Groups 1, 2, and 3 of the CI group and Group 2 of both the CS system and the SI systems, the applicant determined that the effects of general corrosion, crevice corrosion, pitting, MIC, and wear of the seating surfaces of applicable CI valves and safety-related check valves should be managed by an AMP. In NRC Question No. 11.1 (Generic Areas), the staff noted that 10 CFR 54.21(a)(1)(i) excludes valves, other than the valve body, from AMR requirements and that the statements of consideration of the license renewal rule provide the basis for excluding from an AMR for license renewal those structures and components that perform their intended functions with moving parts or with a change in configuration or properties. The staff requested that the applicant provide the basis for its determination that valve internals are subject to an AMR for license renewal. In a letter dated November 12, 1998, the applicant responded to NRC Question No. 11.1 by stating that it is aware of this exclusion but performed this AMR for the applicant's benefit. Therefore, for the valve internals in the groups previously identified, and described in the next three sections, the staff did not evaluate the applicant's AMR because the valve internals perform their intended function with moving parts and changes in configuration and are, therefore, not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.3.3.1.1 Containment Isolation Group

Group 1 is composed of carbon steel piping and components. Internal parts of valves are of alloy steel, stellited carbon steel, and stainless steel. These components are exposed to well water that is stagnant during normal operation. The applicant stated that the components that need aging management are piping, check valves, hand valves, and MOVs. It determined that the aging effects are crevice corrosion, general corrosion, MIC, and pitting.

Group 2 is composed of stainless steel piping and components exposed to treated water or gaseous waste. The applicant stated that the components that need aging management are piping, check valves, control valves, hand valves, MOVs, relief valves, and tanks. The valve bodies are of either stainless steel or carbon steel with internal parts of alloy steels, carbon steel, stellited carbon steel, and stainless steel. The decay tanks are of carbon steel and are internally clad with stainless steel. Flanges and couplings are stainless steel and the bolting is carbon and low- alloy steel. The applicant determined that the applicable aging effects are crevice corrosion, general corrosion, and pitting.

The applicant stated that the occurrence of crevice corrosion, general corrosion, MIC, and pitting is expected to be limited and not likely to affect the intended function of Group 1 and 2 components. The applicant's expectations are based on past experience with systems containing well water. The water has not caused corrosion problems in such systems in the past and is not expected to in the future.

Group 3 identifies wear as a plausible ARDM that requires an AMR of certain valves in the CI group. The valve types for which the wear ARDM is considered plausible, and, which are subject to an AMR, are check valves, control valves, MOVs, and hand valves. Wear results from relative motion between two surfaces and is considered plausible for the disks and seats of valves because of 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 valve seat leakage. As discussed in Section 3.3.3.1 of this SER, an AMR for these valve internals is not required. Therefore, the staff did not evaluate this group.

Group 4 is comprised of the external bolting of MOVs in the containment normal sump drain lines. The bolts are fabricated from carbon and low alloy steels. The sump drain lines contain water that contains boric acid. The applicant stated that if the valves develop a leak, there is a potential for the carbon steel bolts to be exposed to corrosive boric acid. The applicant also stated that these MOVs are the only components in this group that engender an aging management concern about the external surfaces because they are the only carbon steel subcomponents potentially exposed to boric acid from system leakage. The applicant determined that the applicable aging effects are crevice corrosion, general corrosion, and pitting.

The applicant's evaluation of the plausible ARDMs and of the AMPs applicable to Groups 1 through 4 is summarized in Tables 5.5-2 and 5-3 of Appendix A to the LRA.

The staff concurs with the applicant's determination that the effects of corrosion (crevice corrosion, general corrosion, MIC, and pitting) are plausible aging effects and should be managed for license renewal. The staff concurs because the materials mentioned above are known to experience these aging mechanisms when exposed to well water and treated water. On the basis of industry data and experience, the staff concludes no other aging effects are plausible.

Certain components, for example, piping and valves, in the CI group are subject to thermal or mechanical cycling. Structural damage may occur at low or high frequencies as a result of cycles of mechanical, thermal, or pressure cyclical loads. The CI group components are designed in accordance with American National Standards Institute (ANSI) Standard B31.7, which contains fatigue considerations. However, the applicant did not identify fatigue as a plausible aging mechanism for CI group components. In NRC Question No. 5.5.3, the staff requested the applicant's justification for not considering fatigue as a plausible aging mechanism for CI group components. In a letter dated November 12, 1998, the applicant responded that the design for Standard B31.7 Class 2 and 3 components is based on a fatigue stress factor of 1.0, which corresponds to a maximum limit of 7000 cycles of loading. The 7000-cycle bounding limit is well in excess of actual cycling for a 60-year life. Thus, the applicant concluded that fatigue does not need be considered as a plausible aging mechanism for CI group components throughout the period of extended operation. The staff agrees with the applicant's assessment.

3.3.3.1.2 Containment Spray System

Group 1 is composed of components that are exposed to climate-controlled air and whose external surfaces are subject to general corrosion. The materials used are alloy steel for studs, carbon steel for nuts and vessel supports, and carbon steel for the external surfaces of the shell assembly and associated welds. The external surfaces of these components are not normally exposed to a corrosive environment but may be exposed to boric acid as a result of leakage from associated components or nearby systems and components that contain borated water. The applicant determined that the applicable aging effect is general corrosion.

Group 2 is composed of components exposed to chemically treated or borated water. For heat exchangers, the internal environment includes chemically treated water from the component cooling (CC) system. Since the CS system is kept in a standby mode during normal operations, stagnant conditions exist throughout the system. The materials used for components in this group are stainless steel, carbon steel, and alloy steel. Relief valves have Alloy 600 discs and guide rings. The applicant determined that the applicable aging effects for components in Group 2 are crevice corrosion, general corrosion, and pitting.

The applicant's evaluation is summarized in Tables 5.6-2 and 5.6-3 of Appendix A to the LRA. The staff concurs with the applicant's determination that the effects of corrosion (crevice corrosion, general corrosion, and pitting) are plausible aging effects and should be managed for license renewal. The staff concurs because the materials mentioned above are known to experience these aging mechanisms when exposed to treated water. On the basis of industry data and experience, the staff concludes no other aging effects are plausible.

3.3.3.1.3 Safety Injection System

Group 1 addresses general corrosion of the external surfaces of alloy or carbon steel SI system components that can occur if these components are exposed to concentrated boric acid leaking through mechanical joints in the SI piping system.

Group 2 addresses general corrosion, crevice corrosion, and pitting of the internal surfaces of SI systems components that can occur, particularly for those portions of the system that do not have hydrogen overpressure and/or experience low-flow or stagnant conditions in which impurities in the process fluid may concentrate.

Group 3 addresses MIC of the internal surfaces of the stainless steel recirculation headers connected to the emergency sump inside the containment that can occur because this section of piping is exposed to stagnant borated water open to the containment atmosphere for extended periods.

Group 4 comprises SI system components in the safety injection tank (SIT) injection and shutdown cooling (SDC) mode flowpaths for which fatigue is a plausible ARDM. A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity as a result of metal fatigue, which results in the initiation and propagation of cracks in the material. The fatigue life of a component is a function of its material, the environment, and the number and magnitude of the applied cyclic loads. The applicant addressed low-cycle fatigue for components of the SI system. According to the applicant, low-cycle fatigue is plausible in portions of the SI system subjected to thermal transients during the system operation.

The staff reviewed the information regarding fatigue of SI system components contained in Section 5.15 of Appendix A to the LRA for compliance with the requirements of 10 CFR 54.21(a)(3). The applicant suggested that components, such as vent, drain, and test hand valves, instrument isolation hand valves, and relief valves connected to piping, are generally "thin-walled" components and, therefore, do not experience the large temperature gradients that would be necessary to cause significant degradation from fatigue. The staff requested that the applicant provide the technical basis for this conclusion (NRC Question No. 7.18). The applicant deleted the reference to "thin-walled" in the first annual amendment to the LRA. The applicant further stated that these components are outside the main flow path and will not experience significant thermal transients under normal and anticipated conditions. The staff considers this explanation reasonable.

Group 5 consists of heat-affected zones in the stainless steel metal near the penetrations and associated welds that are subject to SCC.

Group 6 consists of the refueling water tank (RWT) perimeter seal, which is an elastomeric material and subject to weathering because it is exposed to the outside environment.

On the basis of the description of the SI system internal and external environments and materials, the staff concludes that the licensee has included all plausible ARDMs. These ARDMs have the potential of causing aging effects (e.g., cracking or loss of material) that, if unmanaged, may result in the failure of SI system components to meet their intended function.

3.3.3.2 Aging Management Programs

The staff's evaluation of the applicant's AMP focused on the following 10 elements constituting an adequate AMP for license renewal: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, the confirmation process, and the administrative controls for license renewal are in accordance with the site-controlled corrective action program pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is presented separately in Section 3.1.5 of this SER. On the basis of this evaluation, the staff concludes that the applicant provided sufficient information in its LRA to show that its AMPs for license renewal satisfy the elements of "corrective actions," the "confirmation process," and "administrative controls."

3.3.3.2.1 Corrosion

This section of the SER discusses the staff's evaluation of the AMPs for the components in the groups that are identified in Sections 3.3.3.1.1, 3.3.3.1.2, and 3.3.3.1.3 of this SER.

With respect to applicable components in Group 1 in the CS and SI systems and Group 4 in the CI group, the applicant has referenced its existing boric acid corrosion inspection (BACI) program to manage the effects of general corrosion of the external surfaces of carbon and alloy steel components exposed to concentrated boric acid. The staff's evaluation of the licensee's BACI program is discussed in detail in Section 3.1.4 of this SER.

With respect to applicable components in Group 2 in the CS and SI systems and Group 5 in the SI system, the applicant has cited three of its chemistry programs, namely, CP-204, "Specification and Surveillance Primary Systems"; CP-206," Specification and Surveillance Component Cooling/Service Water System"; and CP-202, "Specification and Surveillances Demineralized Water, Safety-Related Battery Water, and Well Water Systems," to manage, in part, the effects of general corrosion, crevice corrosion, and pitting of the internal surfaces of the applicable components in the CS and SI systems. The staff's review of the licensee's chemistry programs is discussed in detail in Section 3.1.2 of this SER.

To manage, in part, the effects of general corrosion, crevice corrosion, and pitting of the internal surfaces of the CI group and the CS and SI systems components not covered by the monitoring and testing previously described, the licensee cited its ARDI program. The licensee also credited this program to detect MIC occurring in the internal surfaces of the recirculation headers of the SI system (Group 3) and in CI group components that are exposed to well water (Group 1). The staff's review of the ARDI program is discussed in detail in Section 3.1.6 in this SER. On the basis of this evaluation, the staff concludes that the licensee provided enough information in its LRA to show that the ARDI program is an effective AMP to detect (1) general corrosion, crevice corrosion, and pitting of the internal surfaces of the CI group (Groups 1 and 2), CS system components (Group 2), and the SI systems components (Groups 2 and 3) and (2) the effects of MIC in Group 1 of the CI group and Group 3 of the SI system.

To manage SCC of the RWT penetration welds (Group 5 in the SI system), the applicant credits chemistry program CP-204 (discussed earlier) and system walkdown inspections, as supplemented by an engineering evaluation. Nozzle penetrations for SI system piping connected to the RWT consist of stainless steel pipe penetrating the tank wall joined by a full-penetration groove weld with a fillet cap. The tank was fabricated with a reinforcement plate welded to the outer diameter of the pipe and the tank wall, thereby forming a narrow crevice. The licensee drilled "telltale" holes through these plates. The RWT contains borated water with normal operating parameters of up to 90 psig and 105 °F. The external surfaces of the RWT penetrations are exposed to the environment. In the crevice formed between the reinforcement plate and the tank wall, moisture could accumulate. The licensee stated that SCC occurred in the heat affected zone (HAZ) of penetration welds. The licensee stated that visual observation of a dried boric acid buildup during a system walkdown inspection led to discovery of a pinhole leak inside an outlet nozzle of an RWT. The licensee attributed the leak to SCC at the penetration weld and repaired the weld to correct the deficiency. The applicant stated that as a result of the tough, ductile nature of the construction material (Type 304 stainless steel), the licensee does not expect SCC to lead to catastrophic failure. However, SCC could result in through-wall crack propagation and subsequent leakage. Besides maintaining proper chemistry controls (see previous discussion), the applicant stated that visual inspections for leakage through the "telltale" holes would detect the effects of SCC and allow for timely repair. The applicant credits its procedure MN-1-319, "Structure and System Walkdowns," to detect leakage. The staff's review and evaluation of this program is discussed in detail in Section 3.1.3 of this SER. On the basis of this evaluation, the staff concludes that the applicant provided enough information in its LRA to show that the walkdown inspections will detect SCC of the RWT penetration welds. The applicant plans to modify the program to (1) specifically identify the field-erected tanks within the scope of the performance assessments, (2) provide additional visual inspection criteria specific to detecting leakage near the RWT penetrations, and (3) add guidance regarding approval authority for significant departures from the specified walkdown inspection scope and schedule. To capture this modification, this was identified as Confirmatory item 3.3.3.2.1-1 in the previous SER.

By letter dated July 2, 1999, the applicant committed to revise procedure MN-1-319 to (1) specifically identify the field-erected tanks within the scope of the performance assessments, (2) provide additional visual inspection criteria specific to detecting leakage near the RWT penetrations, and (3) add guidance regarding approval authority for significant departures from the specified walkdown inspection scope and schedule. With this commitment, the staff considers Confirmatory Item 3.3.3.2.1-1 closed.

Because the susceptible locations are not directly accessible, the applicant will complete an engineering review of SCC at the RWT penetrations that will either (1) confirm that detection of leakage through the "telltale" holes is adequate to manage SCC before a challenge to the structural integrity of the penetrations, or (2) include RWT penetrations in the ARDI program (previously described). This engineering evaluation was identified as Confirmatory Item 3.3.3.2.1-2 to capture this element of the applicant's AMP for SCC.

By letter dated July 2, 1999, the applicant committed to perform an engineering evaluation of SCC at the RWT penetrations to either (1) confirm that detection of leakage through the "telltale" holes is adequate to manage SCC before a challenge to the structural integrity of the penetrations, or (2) to include RWT penetrations in the ARDI program. The engineering evaluation and subsequent ARDI, if any needed, will be completed before the end of the current operating term (that is before the end of the 40th year of operation). With the commitment, the staff considers Confirmatory Item 3.3.3.2.1-2 closed.

3.3.3.2.2 Fatigue

The applicant referred to the FMP for managing low-cycle (thermal) fatigue for Group 4 in the SI system. Group 4 is discussed in Section 3.3.3.1.3 of this SER. The FMP is discussed in Sections 3.1.1 and 3.2.3 of this SER. Table 5.15-2 of Appendix A to the LRA identifies the SI components for which low-cycle fatigue is considered a plausible ARDM. The applicant indicated that these components involve the SIT and SDC flow paths. According to the applicant, except for the piping between the SIT outlet check valves and the SIT outlet MOVs, the original design code for the piping is ANSI Standard (USAS) 31.7, Class I. The applicant further indicated that the piping between the SIT outlet check valves and the SIT outlet MOVs was originally designed to ANSI Standard B31.7 Class II requirements and was subsequently upgraded to Class I requirements. The fatigue criteria applicable to Class I are discussed in Section 3.1.1.3 of this SER.

The applicant indicated that the SI nozzles and the SDC outlet nozzles were the limiting locations for low-cycle fatigue in the SI system. These locations are part of the RCS and are also discussed in Section 3.2 of the SER. The applicant described the controlling plant transients and the parameters monitored by the FMP for these locations in response to NRC Question Nos. 7.10 and 7.19. The controlling transients for the SI nozzle are the initiation of SDC and SI check valve test. The controlling transient for the SDC outlet nozzle is plant cooldown from Mode 1 operation. The applicant also identified the specific parameters monitored for each transient in response to the RAIs.

The applicant indicated that the number of cycles of the critical transients for the SI components are not expected to exceed the number assumed in the analyses of record. The applicant provided the expected fatigue usage for the SI nozzles and the SDC outlet nozzles in response to NRC Question No. 7.12. On the basis of the applicant's projection, the fatigue usage of these components is not expected to exceed the allowable limit. According to the applicant, the monitored plant parameter data are collected periodically. These data are evaluated, and updated usage factors are calculated semiannually. The applicant indicates that, if necessary, corrective actions will be initiated before the fatigue limits are exceeded. Corrective actions are discussed in Section 3.1.1 of this SER. The staff finds monitoring and corrective action, if needed, adequate to verify that the fatigue usage limit for SI nozzles and SDC outlet nozzles will not be exceeded during the period of extended operation, and, therefore, this method is acceptable.

The applicant indicated that it has participated in an extensive program undertaken by the Combustion Engineering Owners Group to address thermal stratification concerns. The applicant identified the potential for thermal stratification in the piping between the SIT outlet check valves and the loop inlet check valves in its response to NRC Bulletin 88-08. In the LRA, the applicant committed to complete an engineering review of the industry task group reports to determine whether SI piping thermal stratification analyses are necessary and to determine the impact of such analyses on fatigue usage parameters used by the FMP. In NRC Question No. 7.21, the staff asked the applicant to indicate whether the plans for the engineering review include reanalysis for thermal stratification and describe the manner by which the TLAA for these fatigue analyses will satisfy the requirements of 10 CFR 54.21(c). The applicant responded that the engineering review of the SI piping between the SIT check valves and the loop inlet check valves does include a reanalysis for thermal stratification. The applicant further indicated that this review will determine if the components are bounded by other components in the FMP, and, if they are not bounded, they will be added to the FMP. In the previous SER, the staff requested the applicant to discuss the results of the evaluation, identify additional locations added to the FMP, and describe the controlling transients and parameters monitored for the locations added to the FMP. In addition, the applicant was requested to complete the thermal stratification analysis and modify the FMP, as necessary. This was identified as Confirmatory Item 3.3.3.2.2-1. By letter dated July 2, 1999, the applicant committed to completing the evaluation for these items and making any necessary modifications to the FMP by the end of 2003. With this commitment, the staff considers Confirmatory Item 3.3.3.2.2-1 closed.

As discussed in Section 3.2 of this SER, the applicant's FMP relies on monitoring of critical plant transients for selected SI components to manage thermal fatigue. The staff agrees that monitoring of plant transients causing significant fatigue usage for critical components can adequately represent the remaining SI components. The staff concludes that the applicant's

FMP monitoring approach provides an adequate method to manage thermal fatigue of the SI components.

3.3.3.2.3 Weathering

To manage weathering of the RWT perimeter seal (Group 6 in the SI system), the applicant cited procedure MN-1-319, "Structure and System Walkdowns," to detect leakage. The staff's review of this program is discussed in detail in Section 3.1.3 of this SER. Based on satisfactory closure of the confirmatory item discussed in Section 3.1.3, the staff concludes that the applicant submitted enough information in its LRA to show that the walkdown inspections will detect weathering of the RWT perimeter seals. The applicant plans to modify the program to include additional visual inspection criteria specific to the perimeter seal. To capture this modification, Confirmatory Item 3.3.3.2.3-1 was initiated.

By letter dated July 2, 1999, the applicant committed to provide additional inspection criteria specific to the RWT perimeter seal. The staff concludes that a walkdown of the seal is sufficient to detect weathering of the RWT perimeter seal; therefore, Confirmatory Item 3.3.3.2.3-1 is closed.

3.3.3.3 Time-Limited Aging Analyses

Section 2.1.3.3 of Appendix A to the LRA identified that the fatigue analyses of the NSSS components are TLAAs in accordance with the CLB. Portions of the SI piping connected to the RCS were designed in accordance with the ANSI Standard B31.7 (ASME Class 1). According to the applicant, a specific fatigue analysis was required for the piping designed to the above criteria. Consequently, fatigue analysis is a TLAA for those components of the SI system.

The CCNPP FMP monitors and tracks the fatigue usage for critical components of the NSSS. The staff's evaluation the TLAA is contained in Section 3.2.3.3 of this SER.

3.3.4 Conclusions

For the evaluation of the LRA for the ESFs, the staff has reviewed the information included in Section 5.5, "Containment Isolation Group"; Section 5.6, "Containment Spray System"; and Section 5.15 "Safety Injection System," of Appendix A to the LRA and additional information provided by the applicant in response to the staff's RAIs. The staff concludes that the applicant has demonstrated that the aging effects associated with the ESF systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4 Auxiliary Systems

3.4.1 Introduction

The applicant described its AMR of the auxiliary systems (ASs) for license renewal in three separate sections of its LRA: Section 5.2, "Chemical and Volume Control System (CVCS)"; Section 5.4, "Compressed Air System (CAS)"; and Section 5.10, "Fire Protection (FP)," of Appendix A to the LRA. The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the ASs will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2 Summary of Technical Information In the Application

3.4.2.1 Structures and Components Subject to an Aging Management Review

Section 5.2 of Appendix A to the LRA described the CVCS, which provides control of reactor coolant chemistry through chemical injection for minimizing corrosion, and which provides reactivity control through boric acid injection to maintain coolant activity at the desired level. The CVCS automatically adjusts the volume of coolant in the RCS for various reactor power levels, and controls RCS pressure through auxiliary pressurizer spray during plant startup and shutdown. Major CVCS components consist of piping, accumulator, strainer, tank, flow element, temperature element, heat exchanger, pumps, and various kinds of valves. The CVCS is seismic Category I, and its components are primarily constructed of stainless steel and subjected to an internal environment of borated water. The applicant's selection of device types requiring an AMR is listed in Table 5.2-2 of Appendix A to the LRA.

Section 5.4 of Appendix A to the LRA described the CAS which includes instrument air (IA), plant air (PA), and saltwater air (SA) subsystems in each unit. The IA provides the air supply for pneumatic instruments and valves; the PA provides the air supply for plant maintenance and operation needs; and the SA is the backup air supply. Major components of the CAS are piping, air accumulator, air amplifier, and various kinds of valves. All safety-related components of the CAS are seismic Category I, and are primarily constructed of carbon steel and subjected to an internal environment of compressed air. The applicant's selection of device types requiring an AMR is listed in Table 5.4-1 of Appendix A to the LRA.

Section 5.10 of Appendix A to the LRA described the systems for FP. The FP system includes equipment and facilities important to safety that provide functions of detecting, fighting, and extinguishing fires, and a safe shutdown function in the event of a severe fire. Thus, the FP system is needed to protect safety-related (SR) equipment and structures from fire or explosion. Section 5.10 of the LRA addresses sixteen systems credited with FP functions within its scope. The applicant performed AMRs on 9 of these 16 systems. These 9 systems are SRW, CC, compressed air, diesel fuel oil, AFW, chemical and volume control, RCS, N_2H_2, and MS. These 9 systems have both safety-related and non-safety-related (NSR) pressure boundary (PB) components. The safety-related parts of these systems are addressed in other sections of the LRA; the non-safety-related PB parts of these systems are addressed in Section 5.10. The non-safety-related PB parts of these systems are the subject of the staff's review in this section.

The remaining 7 of the 16 systems rely almost entirely on non-safety-related components to perform their passive FP intended functions. The applicant did not perform component level scoping or an AMR for these systems; that is, it does not describe them under separate sections of the LRA. These systems are addressed in Section 5.10 of the LRA and are listed below. They are also the subject of the staff's review:

- well and pretreated water
- FP
- plant heating
- demineralized water and condensate storage
- condensate
- plant drains
- liquid waste

Also the subject of staff's review in this section of the SER are the fire barrier materials found in the following five structures: IS, primary containment, barriers and barrier penetrations, auxiliary building, and turbine building. The results of the AMR for these structures are provided in Sections 3.3A, 3.3B, 3.3C, and 3.3E of Appendix A to the LRA. These five structures are not addressed in Section 5.10.

3.4.2.2 Effects of Aging

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the auxiliary system components subject to an AMR. The applicant determined that the aging effects on the auxiliary systems from the following "plausible" ARDMs should be managed for license renewal: crevice corrosion, general corrosion, pitting, stress corrosion cracking, wear, and thermal fatigue.

The LRA also contains information on the operating experience of the auxiliary systems regarding aging degradation. For CVCS components, the applicant indicated that charging pump blocks had cracked as a result of high-cycle mechanical fatigue caused by normal operation of these positive displacement pumps. The frequency of such cracking at CCNPP and at other plants has been recognized as an industry-wide problem, and has prompted CCNPP to improve the design of the CVCS and to modify charging pump operating practices, which will help to extend pump life. For the CAS, the applicant indicated that as a result of the CCNPP response to GL 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment," regarding failures of plant IA systems, the CAS has been significantly improved in areas of design, maintenance, operations, and testing. Since then, the CAS has been well maintained and good air quality is ensured by periodic testing, so that the air is low in moisture, temperature, and particulate content. No traces of oil or hydrocarbons have been detected, so oil content is no longer routinely monitored.

For FP systems and components, the applicant indicated that operating experience pertinent to aging includes corrosion in some piping and in uncoated carbon steel components. Corrective actions, including replacement and coating, were implemented.

The following sections describe the effects of aging on the subject fire protection systems.

Effects of Aging According to System Performing FP Functions

The sections that follow describe the effects of aging on fluid systems.

Well and Pretreated Water System: The applicant discussed well water header leaks that developed from corrosion. The applicant stated that the carbon steel pipe was exposed to groundwater without a protective wrap or strong cathodic protection. The applicant stated that other parts of the system had been uncovered and inspected and were in excellent condition primarily because of adequate coating and wrapping. The applicant is currently replacing the corroded portion of piping. Heavy corrosion has also been found on selected penetrations on the pretreated water storage tanks because of failed coatings. The applicant replaced those penetrations for which replacement was appropriate, performed additional inspections, cleaned other penetrations, and then coated all penetrations.

Service Water System: For the historical operating experience, see Section 3.5 of this SER and Section 5.17 of Appendix A to the LRA.

Fire Protection System: The FP system is made up of several subsystems: deluge water spray, sprinklers, hose stations, and extinguishers. The part of the system in scope for the FP AMR is the pressure retaining fire fighting equipment.

The applicant stated that operating experience has been favorable as a result of the use of well water stored in a closed tank. The use of such water results in low levels of organic materials in the piping, thus minimizing microbiologically induced corrosion (MIC). A recent inspection of interior and exterior surfaces of the main water loop, which was installed in the 1970s, showed no evidence of corrosion. The applicant found leakage in a part of the system that supplies water to the warehouses. Plant personnel promptly isolated the leaks and repaired them. The applicant attributed some of the leaks to corrosion of the piping lacking cathodic protection, and some to damage from heavy loads (vehicles) passing over the buried pipes.

Component Cooling System: For the historical operating experience, see Section 3.5 of this SER and Section 5.3 of Appendix A to the LRA.

Diesel Fuel Oil System: For the historical operating experience, see Section 3.7 of this SER and Section 5.7 of Appendix A to the LRA.

Plant Heating System: The applicant identified corrosion-induced leakage in buried portions of the plant heating piping. The applicant replaced the piping with wrapped piping and installed new anodes for the cathodic protection system.

Auxiliary Feedwater System: For the historical operating experience, see Section 3.8 of this SER and Section 5.1 of Appendix A to the LRA.

Demineralized Water and Condensate Storage System: Operating experience consisted of leaks on penetrations on condensate storage tanks (CSTs) due to galvanic corrosion. The applicant will replace the penetrations and coat and or wrap them.

Reactor Coolant System: For the historical operating experience, see Section 3.2 of this SER and Section 4.1 of Appendix A to the LRA.

Main Steam System: For the historical operating experience, see Section 3.8 of this SER and Section 5.12 of Appendix A to the LRA.

Structures With Fire Barrier Materials

Primary Containment Structure: Partitions and ceilings, the concrete base mat, the concrete dome, and the concrete containment wall are classed as fire barriers. The applicant identified no aging mechanisms for the fire barriers in this structure.

Turbine Building Structure, Intake Structure, Auxiliary Building, and Safety-Related Diesel Generator Building Structures: For the turbine building structure, the applicant stated that the components that, contribute as fire barriers are walls, ground-floor slabs, elevated floor slabs, cast-in-place anchors/ embedments, grout, fluid-retaining walls and slabs, beams, baseplates, floor framing, decking, fire doors, jambs, hardware, access doors, jambs, and hardware, caulking and sealants, and watertight doors.

For the IS, the components that, according to the applicant, contribute as fire barriers are columns, walls, cast-in-place anchors/embedments, fire doors, jambs, hardware, caulking and sealants, and expansion joints.

For the auxiliary building and the safety-related diesel generator building the components that, according to the applicant, contribute as fire barriers are walls, elevated floor slabs, masonry block walls, fire doors, jambs and hardware, caulking and sealant, expansion joints, watertight doors, and gypsum board.

The applicant identified weathering of caulking and sealants located outdoors, and expansion joints, as plausible ARDMs. Weathering is caused by temperature and humidity changes, rain, snow, and exposure to ultraviolet light, among other things. The effects of weathering are loss of elasticity, increase in hardness, and shrinkage.

The applicant also identified general corrosion of steel components as a plausible ARDM. The applicant shop-painted or field-painted all structural steel components during plant construction, except for the galvanized grating and metal decking. Uncoated steel corrodes in the presence of oxygen and humidity, and the corrosion may perforate the steel with passage of time.

3.4.2.3 Aging Management Programs

In Tables 5.2-4, 5.4-3, and 5.10-4 of Appendix A to the LRA, the applicant identified the following programs and plant maintenance procedures for license renewal, which will provide adequate aging management for the auxiliary systems:

- Existing CCNPP Administrative Procedure EN-1-300, "Implementation of Fatigue Monitoring," for monitoring and management of the effects of thermal fatigue on CVCS components;

- Existing CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," for mitigation, detection, and management of the effects of crevice corrosion, general corrosion, and pitting on CVCS and RCS components;

- Existing CCNPP PM Checklists IPM 10000 (10001), "Check Unit 1 (2) Instrument Air Quality," for mitigation of the effects of general corrosion for CVCS components;

- Existing CCNPP Technical Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," for mitigation of crevice corrosion and pitting of CVCS components;

- Existing CCNPP Technical Procedure CP-204, "Specifications and Surveillance for Primary Systems," for mitigation of crevice corrosion and pitting of CVCS components;

- Existing Local Leak Rate Test Program, "CCNPP Surveillance Test Procedures M-571A-1(2) and M-571C-1(2)," for detection and management of local leakage that could be the result from wear on CVCS components;

- Existing Local Leak Rate Test Program, "CCNPP Surveillance Test Procedures M-571F-1(2)," for discovery and management of leakage as the result of wear or general corrosion of seating surface of check valves and MOVs in the CAS;

- Existing plant modification to replace the original heat tracing in the CVCS components for mitigation of stress corrosion cracking;

- Existing CCNPP Surveillance Test Procedures M-583-1 and M-583-2, "Pump and Valve IST Program," for discovery and management of the effects of seating surface wear of check valves in the CAS;

- Existing CCNPP Maintenance Program Procedure MN-1-102, "Preventive Maintenance Program," for mitigation of the effects of general corrosion of the CAS carbon steel components;

- Existing CCNPP Program Directive SA-1, "Fire Protection Program," for managing the aging effects of the following systems: FP, diesel fuel oil, partial auxiliary feedwater, partial plant drains, and nitrogen and hydrogen gas;

- Existing CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdown Program," and existing CCNPP Administrative Procedure NO-1-100, "Conduct of Operations," for managing aging effects of certain NSR portions of the following systems with FP functions: well and pretreated water, service water, component cooling, compressed air, plant heating, auxiliary feedwater, demineralized water and condensate storage, partial condensate, partial plant drains, liquid waste, and main steam; and

- New ARDI program for detection of the effects of (1) crevice corrosion and pitting and wear on CVCS components, (2) general corrosion at the containment penetration of the PA subsystem carbon steel components in the CAS, and (3) crevice corrosion, general corrosion, and pitting on the FP-related piping in the NSR portion of the condensate system.

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the auxiliary systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

Because of the number of systems that perform fire protection functions and the complexity of the programs, a more detailed description of programs used for these systems follows below.

The applicant has four different methods to manage aging of SSCs used for FP. The applicant systematically evaluated the following methods in the sequence below to apply them to the subject components:

- Fire protection program activities

- Performance and condition monitoring activities

- AMPs credited for safety-related pressure boundary (safety-related PB) components that apply to the non-safety-related pressure boundary (non-safety-related PB) components

- Normal IPA AMR process

The first method the applicant applies is fire protection program activities.

Fire Protection Program Activities

The first method of the aging management program described by the applicant demonstrates that the aging effects on a system's non-safety-related pressure-retaining components are adequately managed by specific performance and/or condition monitoring activities required by the plant's FP program. The FP program contains maintenance, testing, and inspection criteria to provide reasonable assurance that various non-safety-related systems are capable of performing their intended FP functions. The applicant would implement its corrective action program (see Section 3.1.5 of this SER) if plant personnel detected any abnormal conditions. The applicant stated that such conditions would be detected and repaired before they could impact the passive FP intended function. The applicant's FP program is part of the plant's CLB. The applicant described the FP program in Section 9.9 of its UFSAR. Among the relevant attributes of the program are FP aspects of structures, systems, and component design; inspection and testing of FP systems and equipment; and procurement of FP equipment and material. The applicant stated that plant personnel inspect and test FP equipment and systems upon initial installation and periodically thereafter. Inspections ensure that the installation, maintenance, and modification of the FP equipment conform to design requirements. The applicant conducts the inspection and testing following the guidance of applicable National Fire Protection Association codes and standards, as well as recommendations and requirements of the insurance carrier and the NRC. Plant procedures mandate test frequencies and the testing process. The applicant's Technical Requirements Manual contains applicability, contingency measures, verification requirements, and verification frequencies for those FP systems that protect safe shutdown and safety-related equipment. Plant procedures also identify compensatory actions when equipment required for 10 CFR Part 50, Appendix R, safe shutdown actions become inoperable. The applicant credited this program for fully managing aging effects for the following two systems: diesel fuel oil and nitrogen and hydrogen gas. The applicant credited this program for partially managing aging effects for the following three systems: fire protection, auxiliary feedwater, and plant drains.

If the applicant finds that the FP program activities are not sufficient to manage aging for a system, it considers performance and condition monitoring activities.

Performance and Condition Monitoring Activities

The second aging management method relies on satisfactory performance of functional tests of non-safety-related systems and components. The applicant characterized systems that are in continuous operation during normal operation as undergoing a continuous FP functional test if the system parameters (pressure, temperature, flow, etc.) during normal operations bound those encountered during performance of FP intended functions. The applicant conducted the performance and condition monitoring activities in accordance with procedures MN-1-319, "Structure and System Walkdown," and NO-1-100, "Conduct of Operations." The applicant stated that these activities ensure timely detection of abnormal conditions.

Aging Management Review

The applicant established procedure MN-1-319 to standardize the general intent and method of conducting walkdowns and reporting walkdown results. The procedure meets the requirements for evaluating structure and system material condition in accordance with the maintenance rule. Plant personnel perform visual inspections during the walkdowns, which are performed when plant conditions would provide a good indication of system functionality. Plant personnel perform periodic walkdowns as required for reasons such as material condition assessments and for system reviews before, during, and after outages and as required for plant modifications. Inspection items typically related to aging management include identifying unusual noises, leaks, corrosion, or degraded paint, and identifying system and equipment stress or abuse, such as excessive vibrations, bent or broken component supports, and loosened fasteners. The applicant stated that one of the objectives of the program is to assess the condition of the SSCs so that degraded conditions are identified and documented, and corrective actions are taken before the degradation causes any structure, system, or component to fail to perform its intended function. Plant personnel document and resolve conditions adverse to quality using the applicant's corrective action program.

The applicant established procedure NO-1-100 to address, among other things, the controls and basic standards for conduct of daily shift operations. The procedure requires that operators assess degraded equipment conditions to ensure personnel and affected equipment safety while completing corrective actions. Some of the performance and condition monitoring activities controlled by this procedure are visual inspections of operating spaces each shift during plant operator rounds; collection and analysis of selected data for various operating equipment to detect abnormal or degraded equipment performance; periodic checks to determine equipment performance as determined by manufacturers' recommendations, system engineers' recommendations, and operating needs; surveillance as specified in the plant Technical Specifications to verify that safety-related SSCs continue to function or are in a state of readiness to perform their functions; and diagnosing plant/equipment symptoms for the purpose of identifying/quantifying a degraded parameter/component or verifying the operability of a component. The applicant stated that operator rounds have historically been effective in identifying plant deficiencies.

The applicant credited performance and condition monitoring activities for fully managing aging effects for the following eight systems: well and pretreated water, service water, component cooling, compressed air, plant heating, demineralized water and condensate storage, liquid waste, and main steam. The applicant credited this program for partially managing aging effects for the following three systems: auxiliary feedwater, condensate, and plant drains.

If the applicant finds that the FP program and normal operating condition monitoring activities are not sufficient to manage aging for a system, it applies AMPs credited for safety-related PB components that apply to the non-safety-related PB components.

The applicant's reasoning is that similar materials subjected to environmental conditions can be expected to have the same plausible aging effects and can be managed in the same way regardless of whether the components are safety-related or non-safety-related.

Aging Management Programs Credited for Safety-Related PB Components That Apply to the Non-safety-related PB Components

The applicant applied this third aging management method only to the non-safety-related portions of safety-related systems for which there is an AMR that determined plausible ARDMs and addressed management of aging effects. The applicant stated that similar materials subjected to similar process fluids and environmental service conditions can reasonably be expected to have the same plausible aging effects and can be managed in the same manner regardless of a component's classification as safety-related rather than non-safety-related. The applicant thus relied on the AMPs credited for the safety-related pressure boundary components if the programs are equally applicable to the non-safety related pressure boundary components. The applicant applied the safety-related pressure boundary AMR results to the following two systems: chemical and volume control and reactor coolant.

The applicant applied these first three methods in sequential order to demonstrate that aging effects for an entire system or parts of it, could be adequately managed without a specific determination of ARDMs. In this manner, the applicant reduced the scope of the system requiring further review with the application of each succeeding method. The applicant determined that device types not addressed by any of these first three methods required an AMR that identified the plausible ARDMs and the proper AMPs.

The applicant determined that one system, the Condensate System had components not addressed by the three methods discussed above. For this system the applicant used the normal IPA AMR process.

Normal IPA AMR Process

The applicant credited the ARDI program to manage the plausible ARDMs for the condensate system. The staff's evaluation of the ARDI program is in Section 3.1.6 of this SER.

The following section describes the applicant's AMPs for fire barrier materials.

Turbine Building, Intake Structure, Auxiliary Building, and Safety-Related Diesel Generator Building Structures

To manage weathering effects on caulking and sealants, the applicant relied on its FP program (described in part above) to detect degraded caulking and sealants before there is a loss of intended function. The inspection program provides the requirements and guidance for identification, inspection, and maintenance of caulking and sealants. The applicant tailored the inspection program to the degree of harshness of the environment. The applicant developed the inspection program based on Technical Requirements Manual Section 15.7.10.1; 10 CFR Part 50, Appendix R; and NRC GL- 86-10, "Implementation of Fire Protection Requirements." Plant personnel typically perform these inspections every 18 months in accordance with Technical Requirements Manual Section 15.7.10.1.

To manage corrosion of steel structures exposed to the elements, the applicant stated that all such steel structures are painted or coated, which provides the primary protection against corrosion. To detect coating failures, the applicant credited procedure MN-1-319, "Structure and System Walkdowns," with detecting coating degradation through visual inspections. Plant personnel implement the site's corrective action program upon discovery of significant coating degradation. The staff's evaluation of this program is in Section 3.1.3 of this SER.

3.4.2.4 Time-Limited Aging Analyses

Section 2.1.3.3 of Appendix A to the LRA indicated that the fatigue analysis of NSSS components is included in the TLAAs. Since portions of the CVCS are connected to the RCS, fatigue is also a TLAA for those CVCS components.

3.4.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.2, 5.4, and 5.10 of Appendix A to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation for the auxiliary systems. The staff also obtained the technical assistance of Argonne National Laboratory to review the national codes and standards and industry guidelines cited by the applicant. After completing the initial review the staff issued requests for additional information (RAI) (NRC letters dated September 2 and 4, 1998), and by letters dated November 12 and December 10, 1998, the applicant responded to the RAIs. Also, the staff met with the applicant at the CCNPP plant site between February 10 and February 18, 1999.

The staff's evaluation of the applicant's identification of structures and components subject to AMR appears in Section 2.2 of this SER.

3.4.3.1 Effects of Aging

3.4.3.1.1 Wear and Corrosion-Related Aging Effects

For the CVCS, the applicant determined that aging effects from the following corrosion- related degradation mechanisms should be managed for license renewal: general corrosion, crevice corrosion, pitting, and stress corrosion cracking (SCC). If not actively managed, these degradation mechanisms can cause aging effects and can lead to a loss of intended function from cracking or loss of material. General corrosion of internal surfaces of CVCS components fabricated from ductile iron, zinc-plated steel or carbon steel can occur upon exposure to instrument air because of the potential for moisture carryover in the air. General corrosion of the external surfaces of alloy or carbon steel CVCS components can occur if the surfaces are exposed to borated water or boric acid leaking through mechanical joints in the CVCS piping system. Crevice corrosion and pitting of the internal surfaces of stainless steel CVCS components can occur, particularly for those portions of the system that do not have hydrogen overpressure and low-flow or stagnant conditions where impurities in the process fluid may concentrate. Crevice corrosion and pitting of the carbon steel shell and welds of the letdown heat exchanger can occur because stagnant conditions may be present in idled sections of the system. SCC of the external surfaces of stainless steel CVCS components that have heat tracing can occur because the heat tracing adhesives contain halogens and subject the CVCS components to relatively high temperatures. On this basis, the staff concurs that the applicant has identified all plausible ARDMs for aging management of CVCS.

For the CAS, the applicant determined that aging effects from the degradation mechanisms of wear and general corrosion should be managed for license renewal. These degradation mechanisms can cause wear at the disk/seat of check valves and MOVs from relative motion at tight fitting surfaces, and can cause general corrosion at internal and external surfaces of CAS components constructed of carbon steel from potential exposure to slightly moist air. If not actively managed, these degradation mechanisms can lead to a loss of intended function from valve leakage, component cracking, or loss of material. The staff agrees that uncoated surfaces of carbon steel components corrode upon exposure to humidity. However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configurations, therefore they are not subject to an AMR. The staff agrees that other ARDMs appear unlikely, based on observation of plausible interactions between component materials and their environment.

For FP-related systems and structures, the condensate system is the only system for which the applicant identified specific ARDMs. The identified ARDMs are crevice corrosion, general corrosion, and pitting from exposure of carbon steel piping to stagnant flow conditions. The applicant also identified general corrosion of various carbon steel nuts and bolts from exposure to system fluid through leaking mechanical joints. The staff agrees that carbon steel corrodes upon exposure to oxygen and moisture, and that the uncontrolled chemistry of this isolated portion of the condensate system will only exacerbate the conditions. For various structures with caulking and sealants, the applicant identified weathering as a plausible ARDM. The staff agrees because exposure of caulking and sealants to weathering may result in loss of elasticity, increase in hardness, and shrinkage. If unmitigated, weathering may result in a loss of intended function. For various structures with steel exposed to the atmosphere, the applicant identified corrosion as a plausible ARDM. The staff agrees because unprotected steel corrodes in the presence of humidity and oxygen. In addition, the staff notes that the proximity of CCNPP to the bay indicates that the atmosphere at the plant can be classified as semi-marine. Corrosion in a semi-marine atmosphere can occur many times faster than in a dry, rural atmosphere. Hence, it is important to manage corrosion of steel structures from atmospheric corrosion to maintain functionality. If unmitigated, corrosion may result in a loss of intended function.

On the basis of the description of auxiliary systems' internal and external environments and materials, the staff concludes that the applicant has identified all plausible ARDMs related to corrosion and wear.

3.4.3.1.2 Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity because of metal fatigue, which results in the initiation and propagation of cracks in the material. The fatigue life of a component is a function of its material, the environment, and the number and magnitude of the applied cyclic loads. The applicant addressed both low-cycle and high-cycle fatigue for components of the CVCS. According to the applicant, low-cycle fatigue is plausible in portions of the CVCS subjected to thermal transients during the system operation. In addition, the applicant considered high-cycle fatigue plausible in portions of the CVCS subjected to mechanical vibrations from normal operation of the charging pumps.

3.4.3.2 Aging Management Programs

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about the AMPs discussed in Sections 3.3A, 3.3B, 3.3C, 3.3E, 5.2, 5.4, and 5.10 of Appendix A to the LRA regarding the applicant's demonstration that effects of aging from various ARDMs will be adequately managed so that the intended function of the CVCS, CAS, and FP systems will be maintained consistent with the CLB for the period of extended operation. By letter dated April 8, 1998, the applicant submitted its LRA. By letter dated September 3, 1998, the staff issued RAIs and by letter dated November 4, 1998, the applicant responded to portions of the staff's RAI. The staff also met with the applicant at the CCNPP plant site on February 10, 1999, and again on February 16 through 18, 1999 (NRC meeting summary dated March 19, 1999), to resolve open items.

The staff's evaluation of the applicant's AMPs focused on the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The LRA indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with site-controlled corrective action programs pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is discussed in Section 3.1.5 of this SER. In Section 3.1.5, the staff concluded that the applicant adequately demonstrated that its corrective action program satisfies the elements of corrective actions, confirmation process, and administrative controls.

3.4.3.2.1 Wear and Corrosion-Related Aging Management Programs

For the CVCS, the applicant cited the following AMPs: CP-204, CP-206, MN-3-301, ARDI, IPM 10000 (10001), and plant modification (see Section 3.4.2.3 of this SER).

To manage, in part, the effects of crevice corrosion and pitting of the internal surfaces of the stainless steel CVCS components, the applicant cited its chemistry programs CP-204, "Specification and Surveillance Primary Systems," and CP-206, "Specification and Surveillance Component Cooling/Service Water System." The staff's review of the applicant's chemistry programs is discussed in detail in Section 3.1.2 of this SER.

To manage the effects of general corrosion of the external surfaces of carbon and alloy steel CVCS components exposed to borated water or boric acid, the applicant cited its boric acid corrosion inspection (BACI) program. The staff's review of the applicant's BACI program is discussed in detail in Section 3.1.4 of this SER.

To manage, in part, the effects of crevice corrosion and pitting of the internal surfaces of the stainless steel CVCS components as well as the carbon steel shell and welds of the letdown heat exchanger, the applicant cited its ARDI program. The staff's review of the ARDI program is discussed separately in Section 3.1.6 of this SER.

To manage the effects of general corrosion of the internal surfaces of CAS components fabricated from carbon steel and CVCS components fabricated from ductile iron, zinc-plated steel, or carbon steel from exposure to moisture carryover from IA, the applicant cited PM Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality." The scope of the PM encompasses the entire instrument air system and thus also encompasses the affected CVCS components. The mitigative action associated with this PM activity is periodic measurement of moisture (dew point temperature). The staff finds the parameter monitored acceptable because dew point temperature is an indicator of air moisture content. The applicant measures dew point temperature regularly on a periodic basis (approximately every 12 weeks). On the basis of operating experience to date that includes visual inspections of various internal components of the systems, the staff considers the schedule adequate to detect a problem in the air quality well before there is a loss of intended function. The applicant performs trending of the dew point temperature that the staff finds appropriate to detect any negative trend in moisture carryover that may indicate a problem. The staff finds that the operating experience reported in the LRA demonstrates the effectiveness of the PM activity to preclude excessive moisture in the IA and carryover from IA to the CVCS so that general corrosion at the internal surfaces of IA and CVCS components is effectively prevented and will not result in a loss of intended function. The staff concludes that the applicant has shown that PM Checklists IPM 10000 (10001) is an effective aging management program to mitigate general corrosion of the internal surfaces of CAS and CVCS components from exposure to moisture carryover from IA.

Since the PA subsystem is not maintained to any specific air quality standards, and its carbon steel containment penetration components are occasionally exposed to moist air, general corrosion is a potential degradation mechanism and should be managed. The applicant indicated that the containment penetration portion of the PA subsystem will be included in the new ARDI program, which is discussed separately in Section 3.1.6 of this SER. Regarding general corrosion of the valves' seating surfaces, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration, as discussed in Section 3.3.3.1 of this SER, and therefore, are not subject to an AMR.

To manage SCC of the external surfaces of certain stainless steel CVCS components, the applicant cited a plant modification. The external surfaces of some stainless steel CVCS components are in contact with halogens that are found in the adhesive used to attach the heat tracing to the components' exterior surfaces. The heat tracing keeps the boric acid above the saturation temperature by maintaining a temperature of approximately 160 °F. The applicant plans to replace the original heat tracing and adhesive with heat tracing and adhesive that does not contain halogens. The applicant initiated this plant modification in 1991 in response to the identification of SCC in a section of heat traced CVCS stainless steel piping in 1990. Portions of the original heat tracing have already been replaced. The modification will be completely implemented before the end of the 40th year of operation. The staff finds the scope of the plant modification to be effective in that it encompasses that portion of the CVCS equipped with heat tracing. The applicant has committed to remove and replace all of the original heat tracing. The staff finds that the preventive action, removing the source of halogens, will effectively eliminate SCC as a plausible ARDM. There are no parameters monitored or inspected as part of this plant modification. The staff requested in Open Item 3.4.3.2.1-1 that the applicant include an inspection element to this plant modification to ensure that SCC caused by the original heat tracing adhesive, if it has already started, will be detected and evaluated. The acceptance criterion and its associated basis should also be reported to the staff. In its response to Open Item 3.4.3.2.1-1 dated July 2, 1999, the applicant sent additional information to the staff related to SCC of stainless steel CVCS components. The 1990 failure was attributed to the simultaneous presence of aqueous chloride, temperatures above 150°F, and tensile stress. Although the temperature remains above 150°F for the heat-traced portions of the CVCS, the applicant corrected the damaged hangar that induced the necessary tensile stresses and eliminated the source of the system leakage that wetted the insulation covering the affected pipe. The applicant believes that the recurrence of SCC is unlikely to occur again given the corrective actions taken. In the 9 years since this failure, no additional SCC has been observed based on plant walkdowns for the CVCS. In addition, the applicant noted that the CVCS is a low energy piping system and any SCC failure is unlikely to challenge system functionality. The staff agrees that further occurrence of SCC in the CVCS system appears unlikely given the improvements made since the 1990 failure. The 1990 failure appears to be an isolated incident caused by a combination of circumstances that are unlikely to reoccur. This is supported by the acceptable operation of the system to date. In addition, the staff agrees that SCC failure is unlikely to challenge the system functionality. On this basis, the staff concludes additional inspection of the CVCS piping during the plant modification to replace the heat tracing is not warranted. The staff considers Open Item 3.4.3.2.1-1 closed.

The applicant did not provide justification for the implementation schedule for the plant modification to ensure intended functions are maintained, only stating that it will be completely implemented before the expiration of the current license. Operating experience at CCNPP includes at least one case of externally initiated SCC in CVCS heat-traced piping. Nuclear industry operating experience (NRC Information Notice 85-34, "Heat Tracing Contributes to Corrosion Failure of Stainless Steel Piping," April 30, 1985) has also identified heat tracing as contributing to cracking of stainless steel piping in the presence of chlorides. The justification for the schedule for the plant modification was identified as Open Item 3.4.3.2.1-2 in the previous SER.

In response to Open Item 3.4.3.2.1-2, the applicant provided justification for its schedule for replacing the original CVCS heat tracing, discussed above in response to Open Item 3.4.3.2.1-1. The staff finds that the applicant's corrective actions taken at the time of the original failure and the successful operation of the CVCS since that time supports the applicant's proposed schedule for this plant modification. The staff concludes that the schedule to complete this plant modification is acceptable and considers Open Item 3.4.3.2.1-2 closed.

For the CAS, the applicant cited the following AMPs: Surveillance Test Procedures (STP) STP-M-583-1/2, "Pump and Valve Inservice Testing (IST)"; STP-M-571F-1/2, "Local Leak Rate Test, Penetrations 19A, 19B"; Maintenance (MN) Procedure MN-1-102, "Preventive Maintenance Program," and the new ARDI.

The pump and valve IST program is a part of the overall IST program for the whole plant. Consistent with provisions in 10 CFR 50.55a, the program implements IST in accordance with rules of ASME Code, Section XI, including the types of tests required, frequency of testing, test methods, test pressures, acceptance criteria, and reporting requirements. The staff agrees that the leakage from wear of check valve disk/seats and MOV internal components will be detected in a timely fashion, and the subsequent corrective actions taken as part of the IST program will ensure pressure boundary integrity for the containment air portion of the CAS from plausible wearing of check valve disc and seats. However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration.

As for the FP program, the staff finds the scope of the program acceptable because the specific activities in the program cover the system components performing FP functions. The staff finds the preventive actions taken (periodic maintenance, testing, and inspections) acceptable because they will prevent or identify degraded conditions (through cleaning, replacement, inspection, etc.). Parameters monitored are flow checks, visual inspections, verification of valve positions, battery checks, operability tests, and so forth. The parameters monitored are specific to the component. The staff finds the parameters monitored acceptable because such parameters would indicate degraded conditions. The staff concludes that the applicant will be able to detect aging effects before there is a loss of intended function because of the comprehensive maintenance, testing and inspection performed at established frequencies. Frequencies vary from every 7 days (for pump battery checks) to every 1095 days (for inspection and hydrostatic tests of fire hoses). The staff finds monitoring and trending activities acceptable because periodic maintenance, testing, and inspections will provide adequate information to detect a change in performance that may be associated with aging effects. The staff finds the applicant's acceptance criteria acceptable because any abnormal condition would be addressed before it could affect the FP function. The applicant reported operating experience that demonstrates the applicant's activities have been effective in preventing loss of intended function. The applicant submitted information related to an audit of the FP program conducted in 1996 using an outside consultant that demonstrated the program is consistent with good FP practices and NRC regulatory criteria.

The staff finds the use of performance and condition monitoring activities acceptable for FP-related aging management for specific systems. The staff agrees with the applicant that since the demands on some systems during normal operation are the same as, or greater than, the demands placed on them during mitigation of fires, monitoring of performance during normal operation provides adequate aging management of the system's FP intended function. The applicant conducted the performance and condition monitoring activities in accordance with procedures MN-1-319, "Structure and System Walkdown," and NO-1-100, "Conduct of Operations." For the staff's evaluation of these programs, see Sections 3.1.3 and 3.4.2.3 of this SER.

The staff finds that aging of the passive non-safety-related structures and components in the CVCS and the RCS are adequately managed because they are subject to the same aging management activities as similar safety-related components.

For the turbine building, IS, auxiliary building, and safety-related diesel generator building structures, the staff agrees that the FP program is an acceptable program to manage weathering effects of fire barrier caulking and sealants as discussed in Section 3.4.2.3, above. The staff is conducting a separate review of the applicant's system and structure walkdowns as discussed in Section 3.1.3 of this SER. In light of the satisfactory closure of the confirmatory item in Section 3.1.3.3 of this SER, the staff finds the procedure adequate to manage corrosion of fire barrier steel components.

The staff agrees that the effect of corrosion on steel components is most effectively controlled by coating the steel and visually inspecting the coatings to detect degradation before the steel corrodes significantly. Once degradation is identified, the corrective action program is entered and the degraded coatings are replaced as needed. Thus, the staff concludes that the visual inspection program is effective and acceptable.

3.4.3.2.2 Fatigue

The applicant referred to the FMP for managing low-cycle (thermal) fatigue for the CVCS. The FMP is discussed in Sections 3.1.1 and 3.2.3 of this SER. Page 5.2-14 of Appendix A to the LRA identifies the CVCS subcomponent parts for which low-cycle fatigue is a plausible age related degradation mechanism. The staff asked the applicant to describe the process used to evaluate these CVCS subcomponent parts for low-cycle fatigue, including the selection of the bounding component (NRC Question No. 7.1). The applicant indicated that its FMP review determined that all components in the CVCS from the regenerative heat exchanger to the RCS loop piping, and from the RCS loop piping to the letdown heat exchanger are subjected to fatigue loadings. The applicant also indicated that the design criteria for the piping and valves required fatigue analyses. The applicant further indicated that, as part of the FMP, the design analysis documents were reviewed to determine the area of highest fatigue usage. However, the applicant did not describe the process used to evaluate all the Group 1 components listed on page 5.2-14. Specifically, the applicant's response did not appear to address the HX and TE components. In its July 2, 1999, response to Open Item 3.4.3.2.2-1, the applicant indicated that the TE was included as part of the piping analysis. In addition, the applicant indicated that the result of the review of the HXs is contained in Combustion Engineering Report CE-NPSD-634-P, "Fatigue Monitoring Program for Calvert Cliffs Nuclear Power Plant Units 1 and 2." On the basis of its review of that report, the applicant determined that the expected fatigue usage of the HXs is enveloped by the locations monitored by the FMP. On the basis of the additional information sent by the applicant, Open Item 3.4.3.2.2-1 is closed.

In Appendix A to the LRA, the applicant indicated that the charging inlet nozzle on the RCS loop was the most bounding location for thermal fatigue and that this location is monitored by the FMP. The staff asked the applicant to describe the parameters monitored that are applicable to the charging inlet nozzle and to describe how the monitored parameters are compared to the fatigue analysis of record (NRC Question No. 7.2). The applicant indicated that the monitored transients are loss and recovery of charging flow, and loss and recovery of letdown flow. The applicant also identified the specific parameters monitored for each transient. According to the applicant, the predicted number of loss of letdown cycles will exceed the number of cycles assumed in the fatigue analysis of record for the CVCS. The applicant further indicated that a reanalysis is being performed to justify increasing the number of allowable design cycles. An analysis of the CCNPP CVCS piping is contained in EPRI Report TR-107515. The staff asked several questions about this analysis (NRC Question Nos. 7.3, 7.4, 7.5, and 7.6). In response, the applicant indicated that the EPRI evaluation does not represent the CCNPP fatigue analysis of record.

In response to the staff questions regarding the fatigue evaluation of the CVCS piping contained in EPRI Report TR-107515, the applicant indicated that the CVCS and auxiliary spray piping was reanalyzed after the submittal of the LRA. This reanalysis was performed to account for auxiliary spray transients that were not considered in the original fatigue analysis of the piping. According to the applicant, the original plant design contained a spring-loaded check valve in the charging bypass line at each unit. The purpose of the spring-loaded check valves was to prevent charging flow from entering the piping connected to the RCS loop piping during auxiliary spray operations. However, the valves were installed with their shipping springs and, consequently, the valves did not function properly during the auxiliary spray operations. As a corrective action, the applicant removed the valve's internal components at each unit and replaced them with orifices. The applicant indicated it had completed the revision to the analysis of record to account for the modification. The reanalysis identified additional locations in the CVCS piping with higher calculated fatigue usage than the charging inlet nozzles. The applicant indicated that these locations were added to the FMP. During a site visit to the CCNPP between February 16 and 18, 1999 (NRC meeting summary dated March 19, 1999), the applicant indicated that it had just completed an additional reanalysis of the CVCS system. The results of the reanalysis indicated that the number of allowed loss-of-letdown cycles can be increased without exceeding the fatigue limits for the CVCS components.

The staff questioned whether the modification to the bypass line affected the computation of previous fatigue usage and its projection to 40 and 60 years. According to the applicant, the baseline fatigue usage was adjusted to include earlier usage resulting from the bypass check valve not functioning properly. In addition, the applicant indicated that the FMP now includes the effects of the orifice flow.

Similar to the RPV and RCS discussed in Section 3.2 of this SER, the FMP relies on monitoring of critical plant transients for selected CVCS components to manage thermal fatigue. The staff agrees that monitoring of plant transients causing significant fatigue usage for critical components can adequately represent the remaining CVCS components.

The applicant indicated that the charging pumps, and piping, hand valves, and relief valves between the charging pumps' suction stabilizer and the charging pumps' discharge desurger are subjected to significant vibrational transients from normal operation of the charging pumps. The applicant also indicated that both units of the CCNPP experienced cases of fatigue failures in CVCS piping that were attributed to vibrational loads imposed by operation of the charging pumps. The applicant modified the CVCS to reduce the vibration in the area of the charging pumps. The staff asked the applicant to describe the modifications and indicate whether vibration monitoring was performed subsequent to the modifications (NRC Question No. 7.7). The applicant indicated that the modifications included increasing the size of the discharge desurgers, increasing the thickness of the suction piping, and adding suction stabilizers. The applicant also referred to the staff's evaluation of the modifications contained in a safety evaluation dated October 18, 1979, which contains additional information about the CVCS modifications. According to the applicant, vibration monitoring was performed on the charging pumps to verify the success of the modifications.

To verify that no significant vibration fatigue is occurring for CVCS components, the applicant indicated that a new program will be developed to provide for inspections of representative components. The staff asked the applicant to describe the specific elements of the program that are relevant in monitoring vibration fatigue (NRC Question No. 7.8). The applicant indicated that the CCNPP ARDI program will contain inspections of representative components to detect the effects of vibrational fatigue. The applicant revised the LRA, in the first annual amendment, to indicate that vibrational fatigue is not plausible for the CVCS. The applicant stated that the basis for its finding is that no vibration fatigue failures have been identified since the CVCS modifications, described above, were implemented. The staff agrees with the applicant's evaluation. On the basis of the information provided in the applicant's first annual amendment, submitted to the NRC by letter dated April 2, 1999, Confirmatory Item 3.4.3.2.2-1 is closed.

3.4.3.3 Time-Limited Aging Analyses

Section 2.1.3.3 of Appendix A to the LRA noted that the fatigue analyses of the NSSS components are TLAAs in accordance with the CLB. Portions of the CVCS system connected to the RCS were designed in accordance with a draft American Society of Mechanical Engineers (ASME) Code for Pumps and Valves for Nuclear Power and the American National Standards Institute (ANSI) Standard USAS B31.7, "Nuclear Power Piping Code." According to the applicant, a specific fatigue analysis was required for the piping and valves designed to these criteria. Consequently, fatigue is a TLAA for those components of the CVCS.

The CCNPP FMP monitors and tracks the fatigue usage for critical components of the CVCS. The staff's evaluation of the FMP TLAA is contained in Section 3.2.3.3 of this SER.

3.4.4 Conclusions

The staff has reviewed the information in Section 5.2, "Chemical and Volume Control System"; Section 5.4, "Compressed Air System (CAS)"; and Section 5.10, "Fire Protection," of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review as stated above, the staff concludes that the applicant has provided an acceptable demonstration that the aging effects associated with the auxiliary systems will be adequately managed so that there is reasonable assurance the auxiliary systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5 Cooling Systems

3.5.1 Introduction

The applicant described its AMR of the cooling systems for license renewal in four separate sections of Appendix A to the LRA. These four sections are Section 5.3, "Component Cooling System"; Section 5.16, "Saltwater System"; Section 5.17, "Service Water System"; and Section 5.18, "Spent Fuel Pool Cooling System." The staff reviewed these sections of the application to determine whether the aging effects associated with the cooling systems will be adequately managed so that there is reasonable assurance that the cooling systems will perform their intended functions in accordance with the CLB during the period of extended operation. In the course of its review the staff sent to the applicant requests for additional information (RAI) concerning cooling systems and the applicant responded. Additional information was obtained from the applicant during a meeting held to discuss and resolve issues pertaining to cooling systems.

3.5.2 Summary of Technical Information in the Application

3.5.2.1 Structures and Components Subject to an Aging Management Review

Section 5.3 of Appendix A to the LRA describes the component cooling (CC) system. The CC system is designed to remove heat from various plant auxiliary systems. The system's components are rated for maximum-duty requirements during normal and shutdown-cooling operation and are also capable of removing heat during a loss-of-cooling accident. 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, and associated valves, piping, instrumentation, and controls. The components are constructed of carbon steel, stainless steel, cast iron, bronze, cast brass, aluminum bronze, and butyl rubber. The internal environment is water at a design pressure of 150 psig and a maximum design temperature of 180 ^{o}F, chemically treated to control corrosion. The CC system includes a number of components (e.g., valves, instruments) that are flange-bolted, welded in place, or gasketed. Within the CC system there are regions of low or stagnant coolant flow.

Section 5.16 of Appendix A to the LRA described the saltwater system (SWS). The SWS is designed as a safety-related system. Each unit has three SWS pumps that provide the driving head to move saltwater from the IS through the system and back to the circulating-water discharge conduits. The system is designed so that each pump has sufficient head and capacity to provide cooling water for the service water (SRW) system, component cooling water (CC), and emergency core cooling system (ECCS) pump room coolers, as required by 10 CFR Part 50, Appendix A. The SWS in each unit consists of two subsystems. Each subsystem provides saltwater to a service water heat exchanger, a component-cooling heat exchanger, and an ECCS pump room cooler in order to transfer heat from these heat exchangers and coolers to the Chesapeake Bay. Seal water for the circulating water pumps, which supply water to the main condensers, is supplied by both subsystems. Each safety-related subsystem has the following major components: piping and valves, pumps/motors, heat exchangers, coolers, basket strainers, air accumulators, and various instruments. The components are constructed of carbon steel, cast iron, 70-30 copper-nickel, ductile iron, cast steel, bronze, stainless steel, monel, and titanium. Carbon steel or cast iron piping are lined with cement mortar, Neoprene, Saran Kynar, Belzona (brand name), Tuboscope (brand name), Buna-N, natural rubber, hard rubbers, polypropylene, and coal tar epoxies. The internal environment is saltwater.

Section 5.17 of Appendix A to the LRA describes the service water system (SRW). The SRW in each unit is a closed-loop cooling-water system that, in normal operation, supplies chemically treated water to two safety-related, seismic Category I trains and a common non-safety-related, non-seismic train. The safety-related trains supply cooling water to the spent fuel pool heat exchanger, the containment cooling units, the blowdown recovery heat exchangers, and the emergency diesel generators. The non-safety-related train supplies cooling water to various turbine building loads. The system for each unit has been divided into two trains in the auxiliary building to meet the single-failure criterion. Each-safety-related train has the following major components: piping and valves, head tank, pumps/motors, heat exchangers, coolers, and instruments. The components are constructed of carbon steel, cast iron, and stainless steel. The internal environment of the SRW is water at a normal service pressure of 102 psig and normal operating temperature of 130 ^{0}F, chemically treated to control corrosion. The SRW includes a number of components that are flange-bolted, welded in place, or gasketed. Within the SRW there are regions of low or stagnant coolant flow.

Section 5.18 of Appendix A to the LRA describes the spent fuel pool cooling system (SFPCS). The SFPCS consists of two half-capacity pumps and two half-capacity heat exchangers in parallel, a bypass filter (which removes insoluble particulates), a bypass demineralizer (which removes soluble ions), and various piping, valves, and instrumentation. The spent fuel pool is located in the auxiliary building. The spent fuel pool is divided into identical halves, each serving one reactor unit. Both new fuel and spent fuel may be stored in the fuel pool. The SFPCS has the following major components: piping and valves, pumps and motors, heat exchangers, a filter/strainer, a demineralizer, and instruments. The components are constructed of carbon steel, low allow steel, alloy stainless steel, elastomer lining, and some of the components are zinc-plated or painted on the external surfaces. The internal environment for all major components, with the exception of the shell-side of the heat exchangers, is borated water, with approximately 2500 ppm boron. The shell-side of the heat exchangers is exposed to treated demineralized water containing additives for corrosion control.

The applicant classified the components in the cooling systems subject to an AMR into the following groups: piping, valves, tanks, filters/strainers, heat exchangers, coolers, demineralizers, pumps/motors, instruments, and air accumulators. The components in all these groups are required to maintain the integrity of the cooling systems.

3.5.2.2 Effects of Aging

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the components subject to an AMR. The applicant determined that the aging effects from the following "plausible" ARDMs should be managed for license renewal: crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion (MIC), cavitation erosion, pitting, erosion/corrosion, particulate wear erosion, selective leaching, elastomer degradation, radiation damage, and wear. The applicant's evaluation is summarized in Tables 5.3-3, 5.16-3, 5.17-3, and 5.18-3 of Appendix A to the LRA.

3.5.2.3 Aging Management Programs

The applicant identified the following AMPs for the cooling systems for license renewal in the LRA:

- CCNPP "Specifications and Surveillance for CC/SRW Systems," CP-206 (existing program)

- CCNPP "Component Cooling Pump Overhaul and Inspection," PUMP-14 (existing program)

- Local Leak Rate Tests (LLRTs) STP M-571E-1 and M-571E-2 (existing program)

- CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program" (existing program)

- Repetitive Tasks 10122063 through 10122068, 10122096 through 10122102, 20122067 through 20122072, 20122100 through 20122106, 10122107 through 10122110, 10122086 through 10122088, and 20122092 through 201220094 (existing programs)
- Checklists MPM04194, MPM01180, and MPM01181 (modified program)

- CCNPP Procedure Saltwater Pump Overhaul PUMP-03 (modified program)

- Checklists IPM10000 and IPM10001 (existing program)

- Repetitive Tasks 10152023, 10152024, 20112006, 20112027, 20152020, and 20152021 (existing programs)

- Checklists MPM00005 and MPM00006 (existing program)

- Checklists MPM05000 and MPM05101 (modified program)

- Repetitive Tasks 10122095 and 20122099 (modified program)

- Checklists for SRW Relief Valves: MPM01013, MPM01147, MPM01153, and MPM01155 (existing program)

- SRW Pump Overhaul, CCNPP PUMP-15 (modified program)

- Boric Acid Corrosion Inspection (BACI) Program (MN-3-301) (existing program)

- SFPCS pump housing inspection (repetitive Tasks 00672007, 00672008, modified to explicitly present inspection requirements) (modified program)

- Age Related Degradation Inspection (ARDI) Program (new program)
- CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns" (existing program)

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the cooling systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.5.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-Limited Aging Analyses," of Appendix A to the LRA states that no time-limited aging analyses (TLAAs) apply to the cooling systems.

3.5.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.3, 5.16, 5.17, and 5.18 of Appendix A to the LRA. The review was performed to ascertain that the effects of aging on the cooling systems will be adequately managed so that there is reasonable assurance that the cooling systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1 Effects of Aging

As described above, the components in the cooling systems are constructed of the following materials: carbon steel, stainless steel, internally lined carbon steel, 70-30 copper-nickel, bronze, brass, cast iron, cast steel, low alloy steel, red brass, copper nickel, aluminum bronze, and various lining materials. The internal environments of the various subsystems consist of water treated with hydrazine for corrosion control, borated water, and saltwater. The external environment is air, with the exception of below-ground saltwater piping, that is, external environment is soil. The external surfaces of buried piping are protected from the soil with a multiple layer wrap and enamel coating, in accordance with industry standard practice. The applicant identified the applicable ARDMs as crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion (MIC), pitting, erosion/corrosion, cavitation erosion, particulate wear erosion, selective leaching, elastomer degradation, radiation damage, and wear. Although, in requiring management of aging effects the license renewal rule does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds the applicant's approach of identifying and evaluating ARDMs acceptable because aging effects are results of ARDMs.

The operating experience information in Appendix A to the LRA indicates that the CC system has, in general, performed well and no major problems have been identified that impaired the system function. However, the CC system cross-connect valves have experienced minor leakage because of poor design. The applicant has removed and replaced these valves with an upgraded valve design and the problem has been resolved. Also, the CC system has experienced water hammer while switching the CC system pumps. The water hammer has been determined to originate in the CC system outlet check valves. The applicant plans to replace these check valves to eliminate further water hammer.

Operating experience with the SWS system revealed problems caused by graphitic corrosion on the SWS side of the CC system heat exchanger channel heads. As a result of this finding all CC system and SWS heat exchanger channel heads were coated with coal tar epoxy to prevent future corrosion. The current design for these heat exchangers uses neoprene rubber lining in the channel heads rather than the coal tar epoxy coating used previously. The SWS has also experienced through-wall leakage in the carbon steel above-ground piping lined with concrete. The cause of leakage was determined to be damage to the concrete lining and subsequent corrosion of the bare metal exposed to saltwater. Leaks were also observed in the discharge piping of one of the SWS pumps. The cause was determined to be corrosion. The corrosion occurred because the grout lining failed. The applicant has replaced the grout lining with epoxy-type lining. The SWS side of the SRW heat exchangers has experienced erosion/corrosion in the past. The existing SRW system heat exchangers have experienced degraded thermal performance because of fouling. Because of the erosion/corrosion and the reduced thermal performance, the applicant has committed to replace the heat exchangers. The new heat exchangers will use titanium plates and ethylene propylene diene monomer (EPDM) for the gaskets to protect against the problems experienced with the current heat exchangers.

Operating experience with the SRW indicated recurring SRW heat exchanger tube leakage for the past several years. The leakage was primarily due to erosion and corrosion. In 1985, the applicant installed 8-inch-long sleeves in the inlet section of each tube (both plugged and unplugged) in the No. 11 SRW heat exchanger. Total SRW leakage was subsequently measured to be 0.43 gpm. The applicant evaluated this low leakage as not safety significant. Routine monitoring of SRW head tank levels and weekly surveillance to quantify SRW leakage were determined to be adequate to alert operators to increasing leakage.

Operating experience with the SFPCS piping revealed several instances of cracking due to high-cycle fatigue. The cracking was caused by cavitation-induced vibration inherent to the original design of the system. Subsequently certain orifices and valves were modified to eliminate cavitation. These improvements have kept the SPFCS piping from cracking.

Given below are the results of the staff's evaluation of the degradation mechanisms and AMPs applicable to each of the cooling systems.

3.5.3.1.1 Component Cooling System

The applicant determined that numerous potential and plausible ARDMs are applicable to the CC system. The applicant grouped these ARDMs as follows: (1) crevice corrosion and pitting, (2) erosion/corrosion, (3) general corrosion, (4) rubber degradation, (5) selective leaching, and (6) wear. The applicant described and evaluated the effects of each of these ARDM groups on the component materials, outlined the methods to manage aging, identified AMPs, and demonstrated the adequacy of the proposed aging management for each of the identified ARDMs.

The applicant has determined that fatigue is not a plausible aging mechanism for the CC system. In NRC Question No. 5.3.4, the NRC staff requested that the applicant justify and describe the criteria from the determination that low-cycle fatigue and corrosion fatigue are not plausible mechanisms for the piping, check valves, and pump drive assemblies of the CC system. In response to NRC Question No. 5.3.4, the applicant stated that the service loading amplitudes and frequencies in the CC system were well below magnitudes that would result in fatigue failures of CC system piping, check valves, control valves, and pump casings. The CC system maintains a relatively steady service temperature of approximately 95 °F – 110 °F and a pressure of 80 psig, thus lacking the temperature and pressure cycles that would make these fatigue mechanisms plausible. Because of the absence of conditions that would result in fatigue, the NRC staff finds this explanation satisfactory and concurs with the applicant's assessment that fatigue is not a plausible ARDM for the CC system.

On the basis of industry data and experience, the staff concludes there are no other applicable ARDMs for the CC system. Given below are the results of the NRC staff evaluation of the ARDMs that were evaluated by the applicant in six groups

3.5.3.1.1.1 Crevice Corrosion and Pitting

The piping material in the CC system is carbon steel, and various parts of automatic vents and various valves are made of carbon steel, stainless steel, cast iron, brass, and aluminum-bronze. The pumps and tank are made of carbon steel, and radiation elements are made of stainless steel. Temperature elements and temperature indicators are made of carbon steel and temperature-indicating controllers are made of stainless steel. The internal environment of the CC system is water treated chemically to control corrosion. Its design pressure is 150 psig and its maximum design temperature is 180 °F.

To protect the CC system components from corrosion damage, the applicant is monitoring its chemistry parameters using CCNPP Chemistry Procedure CP-206, "Specification and Surveillance for Component Cooling/Service Water Systems." The staff's review and evaluation of the applicant's water chemistry program is discussed in detail in Section 3.1.2 of this SER. The procedure provides for monitoring the CC system chemistry to control the oxygen, chlorides, other chemicals, and contaminants. The chemistry parameters are monitored at various frequencies from three times a week to once a month. Operational experience with the CP-206 procedure has not shown any problems related to its use with respect to the CC system. In 1996 the applicant revised the procedure to include dissolved iron as a chemistry parameter. Dissolved iron is measured to discover any unusual corrosion of the CC system carbon steel components.

As an additional assurance for components other than CC pumps, the applicant will establish the ARDI program to verify that CC components are not degrading. The CC system pumps are inspected using CCNPP PUMP-14, "Component Cooling Pump Overhaul." The procedure instructs the user to inspect the pump impeller and shaft for erosion, corrosion, and pitting, and to inspect all pump parts for wear, corrosion, and mechanical damage.

As an additional assurance, the applicant will establish the ARDI program to verify that these components are not degrading. The staff's evaluation of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

On the basis of the mitigative effects of the water chemistry program and the assurance provided by the inspections noted above, the staff concludes that those programs will provide adequate protection for the components in the CC system against aging effects caused by crevice corrosion and pitting and will provide reasonable assurance that the CC system will perform its intended function in accordance with the CLB during the period of extended operation..

3.5.3.1.1.2 Erosion/Corrosion

CCNPP does not have any specific program for controlling erosion/corrosion in the CC system. However, the staff expects no significant damage to the CC system components due to erosion/corrosion because the normal operating temperature and velocities in the system are below the levels at which significant erosion/corrosion occurs.

In NRC Question No. 5.3.5 the staff expressed its concerns related to the carbon steel piping bends, elbows, and nozzles that may be vulnerable to wall thinning because of erosion/corrosion—an identified age related degradation mechanism for the CC system piping. The staff also asked the applicant to describe the specific evaluations that have been performed (or will be performed) to ensure structural integrity of the piping in spite of the effects of cyclic fatigue at locations where wall thinning may occur during the extended period of operation. In its response, the applicant stated that erosion/corrosion is expected to be minimal but plausible for the CC system. The normal CC system operating temperature of approximately 95 °F–110 °F is below the levels at which significant erosion/corrosion is expected to occur. Cyclic fatigue by itself is not considered a plausible aging mechanism; however, cyclic fatigue in the presence of significant wall thinning from severe erosion/corrosion would be a concern. Such conditions are not expected to occur in the CC system since erosion/corrosion is expected to be minimal at low operating temperature. Fatigue was, therefore, not considered a plausible aging mechanism for the CC system. The staff finds the applicant's response acceptable.

The applicant stated that an ARDI program will be utilized to examine representative piping for identification of any potential erosion/corrosion that may occur. Corrective actions will be performed that would prevent thinning of the component below the limit at which fatigue might be plausible. The staff's review and evaluation of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

On the basis of the low likelihood of significant erosion/corrosion in this system, the staff concludes that there is adequate protection for the components in the CC system against aging effects caused by erosion/corrosion and reasonable assurance that the CC system will perform its intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.1.3 General Corrosion

The components in the CC system that may be affected by general corrosion are made of carbon steel and cast iron materials. The following types of components were determined to be susceptible to general corrosion: piping; check, control, hand, and relief valves; pumps; temperature elements; temperature indicators; and tanks.

The effects of general corrosion are mitigated by chemistry control, monitoring pertinent chemistry parameters through the CCNPP CP-206 procedure. The CC system pumps are inspected for general corrosion using CCNPP Procedure PUMP-14, "Component Cooling Pump Overhaul." Also, the CCNPP ARDI program will require that components be inspected for general corrosion. These inspections will provide additional assurance that the plausible general corrosion effects are effectively managed. The staff's reviews and evaluations of the water chemistry and ARDI programs are discussed in detail in Sections 3.1.2 and 3.1.6, respectively, in this SER.

On the basis of the mitigative effects of the water chemistry program and the additional assurance provided by ARDI, the staff concludes that these programs will provide adequate protection for the components in the CC system against aging effects of general corrosion and provide reasonable assurance that the CC system will perform its intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.1.4 Rubber Degradation

Degradation of rubber is a plausible ARDM for the CC system containment isolation valves, which have butyl liners that can degrade with aging when exposed to treated CC system water. Rubber degradation could result in the valves leaking. There are no reasonable methods of mitigating rubber degradation of the control valves' surfaces. Therefore, no programs are credited with mitigating rubber degradation in the control valves.

Aging Management Review

The applicant has indicated that several procedures in the existing CCNPP Containment Leak Rate Program will be used to detect the leakage, so that corrective actions may be taken. The Containment Leak Rate 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." Appendix J specifies containment leakage testing requirements, including the types of tests required, testing frequency, test methods, acceptance criteria, and reporting requirements. The applicant stated that Appendix J should provide sufficient information for estimating the degree of damage to a valve's liner caused by aging. The staff agrees that the implementation of Appendix J requirements will provide reasonable assurance that the damage to the valve liner will be adequately managed.

This ARDM is applicable to valve internals. As discussed in Sections 3.3.3.1 and 3.5.3.1.1.6 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and, therefore, are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.5.3.1.1.5 Selective Leaching

The applicant determined that selective leaching is a plausible ARDM for the automatic vents, control valves, hand valves, relief valves, and solenoid valves. These components are made of brass, cast brass, cast iron, and aluminum-bronze. They may, therefore, undergo selective leaching, which is the removal of one element from a solid alloy by corrosion. Cast iron is susceptible to selective leaching and the process is called graphitization.

The applicant mitigates the effects of selective leaching by maintaining proper water chemistry through CCNPP Procedure CP-206. To provide additional assurance that the plausible selective leaching does not cause significant damage, the components subjected to this ARDM will also undergo inspections under the ARDI program. The staff's reviews and evaluations of the water chemistry and ARDI programs are discussed in detail in Sections 3.1.2 and 3.1.6, respectively, of this SER. The staff's review of the chemistry program concluded that the applicant has an acceptable water chemistry program.

On the basis of the mitigative effects of the water chemistry program and the additional assurance provided by the ARDI, the staff concludes that these programs will provide adequate protection for the components in the CC system against aging effects of selective leaching and provide reasonable assurance that the CC system will continue to perform its intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.1.6 Wear

The applicant determined that check and control valves are susceptible to wear. Wear results from relative motion between two surfaces (adhesive wear), from the influence of hard abrasive particles (abrasive wear), or from sliding under the influence of a corrosive environment (fretting). The applicant concluded that there were no reasonable methods of mitigating wear of the valve surfaces. The only effective ARDM managing procedure for wear is to inspect and test the valves that are susceptible to wear. CCNPP procedures STP M-571E1 and M571E-2, which are a part of the CCNPP Containment Leakage Rate Program, will be used by the applicant in monitoring the CC system containment isolation control valves for leak tightness. Although the system check valves are subject to ISI and IST, in accordance with the provisions of 10 CFR 50.55(a), inspection of the check valves in the CC system will be included in the applicant's ARDI program to verify the effectiveness of the applicant's aging management program. The staff's review and evaluation of the ARDI program are discussed in Section 3.1.6 of this SER.

This ARDM is applicable to valve internals. As discussed in Sections 3.3.3.1 and 3.5.3.1.1.6 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and, therefore, are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.5.3.1.2 Saltwater System

The applicant determined that the numerous potential and plausible ARDMs are applicable to the saltwater system (SWS). The applicant put these ARDMs in six groups: (1) general corrosion, crevice corrosion, MIC and pitting in the components without internal lining; (2) crevice corrosion, galvanic corrosion, general corrosion, MIC, particulate wear erosion, pitting, and elastomer degradation in the components with internal lining; (3) general corrosion in the components exposed to air internal environments; (4) crevice corrosion, erosion/corrosion, general corrosion, MIC, pitting, and elastomer degradation in the CC system and SWS heat exchanger; (5) crevice corrosion, general corrosion, MIC, and pitting in the ECCS pump room air coolers; and (6) crevice corrosion, erosion/corrosion, MIC, particulate wear erosion, and pitting in the flow orifices. For each of these groups of ARDMs, the applicant described and evaluated the effects of the ARDMs on the material, outlined the methods to manage aging, identified the AMPs, and demonstrated the adequacy of the proposed aging management for each of the identified ARDMs.

On the basis of industry data and experience, the staff concludes there are no other applicable ARDMs for the saltwater system. The following is the staff's evaluation of the AMPs for these ARDMs.

3.5.3.1.2.1 Crevice Corrosion, General Corrosion, MIC, and Pitting in the Components Without an Internal Lining

This group consists of piping, valves, temperature indicators, and temperature test points without any lining on their internal surfaces. The applicant determined that general corrosion, crevice corrosion, MIC, and pitting were plausible ARDMs for the components in this group. One or more of these ARDMs could affect the components exposed to saltwater. The materials that are subject to crevice corrosion, MIC, and pitting are: red brass, 70-30 copper-nickel, bronze, cast bronze, cast brass, stainless steel, and Monel. Materials subject to general corrosion are low alloy and carbon steel bolting.

The applicant described the ARDMs affecting this group. The applicant concluded that no mitigation measures were practical for these ARDMs and consequently proposed no program for mitigating component aging in this group. However, the applicant indicated that the ARDMs listed above are mitigated by proper selection of materials of construction. Proper selection of construction materials effectively controls corrosion to levels that are not likely to affect the intended function of SWS components constructed of corrosion-resistant materials, such as brass, bronze, copper-nickel alloys, and stainless steel, that have been developed for saltwater service. To verify that no significant damage to the affected components is occurring, the applicant credited its ARDI program to provide for inspections of these components. The staff's review of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

On the basis of the materials of construction and the additional assurance provided by the ARDI, the staff concludes that this program will provide adequate protection for these components in the SWS against aging effects of these ARDMs and will provide reasonable assurance that they will continue to perform their intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.2.2 Crevice Corrosion, Galvanic Corrosion, General Corrosion, MIC, Particulate Wear Erosion, Pitting, and Elastomer Degradation in the Components With an Internal Lining

This group consists of piping, basket strainers, valves, and pumps made of cast iron, ductile iron, cast steel, and carbon steel. These components are exposed to saltwater environment and are protected by different types of internal coatings. In addition, the pipes buried underground and externally exposed to the soil have their external surfaces protected by multiple-layer wrap and enamel coatings. The coatings provide adequate protection if their integrity is maintained; if they fail, the components may be damaged by crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting. The applicant, therefore, included these ARDMs in the aging management program. In addition, the program addresses ARDMs caused by particulate wear erosion, which is only plausible for piping with cement mortar lining, and elastomer degradation, which is plausible for components with lining constructed of Neoprene, Buna-N, natural rubber, and hard rubber. The following materials were used for coating internal surfaces: cement mortar, Neoprene, Saran, Kynar, Buna-N, natural rubber, polypropylene, coal tar epoxy, and Belzona and Tuboscope (last two being brand names).

The component linings when not damaged provide in most cases a sufficient degree of protection. To ensure their integrity and assess any potential damage from the ARDMs that are not eliminated by the presence of linings, the applicant subjects the components in the SWS to inspections through the existing PM program. However, not all the components are included in these inspections. Therefore, the applicant will extend these inspections to include all the affected components in its new ARDI program. The staff's review and evaluation of the ARDI program is discussed in Section 3.1.6 of this SER.

On the basis of the existing periodic inspections supplemented by ARDI, the staff concludes that these programs will provide adequate protection for the components in these SWS components against aging effects of this ARDM and provide reasonable assurance that they will continue to perform their intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.2.3 General Corrosion in the Components With Air Internal Environment

This group consists of accumulators and valves that have air as internal environment and have carbon steel and iron subcomponents. The expected effect of general corrosion on the internal surfaces would be surface rust. The PM program mitigates the effects of corrosion by minimizing moisture inside the components.

The applicant has inspected the piping immediately downstream of the saltwater compressors, where the worst case of corrosion was expected. The inspection revealed only very light surface rust on the inside of each piece. After 20 years of operation, approximately 60 percent of the pipe interior is free of rust and looked new. Measurement showed negligible loss of wall thickness. On the basis of the mitigative effects of the PM program performed on this group of components, the staff concludes that continued maintenance of the air system to industry standards will provide adequate protection against the aging effects of general corrosion in components with an air internal environment and provide reasonable assurance that these components will continue to perform their intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.2.4 Crevice Corrosion, Erosion/corrosion, General Corrosion, MIC, Pitting and Elastomer Degradation in the CC and SRW Heat Exchangers

The applicant identified the materials for the CC and SRW heat exchanger systems as carbon steel shells and channel heads, aluminum-bronze tubesheets, copper-nickel tubes, channel and channel head rubber/neoprene linings, and carbon and low-alloy steel bolting. The applicant identified the following ARDMs to be applicable to the CC system and SRW heat exchangers: crevice corrosion, erosion/corrosion, general corrosion, MIC, pitting, and elastomer degradation. The effects of crevice corrosion, general corrosion, MIC, and pitting are the same as in the components without internal linings, and degradation of elastomer is the same as in the components with internal lining.

Erosion/corrosion is an increased rate of corrosive attack on a metal because of relative movement between a corrosive fluid and the metal surface. Erosion/corrosion occurs at the inlet side of the tubes in the heat exchangers and is caused by a turbulence in the fluid flowing between the heat exchanger head and the tubes.

The applicant concluded that for the shell side of the heat exchangers, the effects of crevice corrosion, general corrosion, and pitting can be mitigated by minimizing the exposure of the shell to an aggressive environment caused by improper CC system and SRW water chemistry. Minimizing the impurities in the water will prevent the corrosive mechanisms from occurring. The staff evaluation of the water chemistry program is discussed in detail in Section 3.1.2 of this SER. For the tube side, with the components subjected to a saltwater environment, corrosion of the channel heads is mitigated by a rubber/neoprene lining.

The applicant is using visual inspections to ascertain that no significant degradation is occurring in the heat exchangers. Technical procedure CP-206 is credited with managing the effects of crevice corrosion, general corrosion, and pitting for the shell side of the heat exchangers. For the tube side of the heat exchangers, the CCNPP PM program is credited for ensuring that degradation of the heat exchangers will be controlled. Specifically PM checklists MPM00005 and MPM 00006 will be used to perform eddy current testing of the heat exchanger tubes. Periodic cleaning and inspection of the tube side will be carried through Repetitive Tasks 10152023, 10152024, 20112006, 20112027, 20152020, and 20152021. These tasks will require inspecting the channel heads, bolts, and sacrificial anodes, and cleaning the tubes every quarter.

The staff concludes that guidance provided by CP-206 procedure for maintaining shell side water chemistry and periodic inspections and cleaning of the heat exchanger tubes under the PM program will provide adequate protection for these heat exchangers against the aging effects of these ARDMs and provide reasonable assurance that these heat exchangers will continue to perform their intended function in accordance with the CLB during the extended period of operation.

3.5.3.1.2.5 Crevice Corrosion, General Corrosion, MIC, and Pitting of the ECCS Pump Room Air Coolers

The internal environment for the ECCS pump room air coolers is saltwater on the tube side and air on the shell side. Crevice corrosion, MIC, and pitting are plausible ARDMs for the channel heads and tubes. The channel heads are constructed of cast iron and the tubes are copper-nickel. Crevice corrosion, general corrosion, and pitting are plausible ARDMs for the cooler bolting, which is constructed of carbon and alloy steel. Although the channel heads are lined with epoxy to protect the cast iron wall from the saltwater environment, they are still prone to crevice corrosion, pitting, and MIC when the protective coating fails.

The applicant conducts periodic visual inspections and testing for the tube side of the coolers through the existing CCNPP PM program to determine if any degradation is occurring. Specifically, PM specified in Checklist MPM 05101 for the ECCS pump room air coolers is performed every 24 weeks. The checklist requires inspections of the channel heads and tubes. These routine activities will identify any degradation of the pressure boundary, and corrective action will be taken to repair any deficiencies discovered. This ensures that the effects of crevice corrosion, general corrosion, MIC, and pitting will be managed for the ECCS pump room air coolers. The staff concludes that performing the specified PM on the ECCS pump room coolers will provide adequate protection of these air coolers against the aging effects of these ARDMs and will provide reasonable assurance that the coolers will perform their intended function in accordance with the CLB during the period of extended operation.

3.5.3.1.2.6 Crevice Corrosion, Erosion/Corrosion, MIC, Particulate Wear Erosion, and Pitting in the Flow Orifices

The material of construction for the flow orifices is stainless steel, which is resistant to most forms of corrosion. However, because the orifices are subject to the saltwater environment, under certain circumstances, they could be subjected to the following ARDMs: crevice corrosion, erosion/corrosion, MIC, particulate wear erosion, and pitting.

The applicant has determined that performing visual inspections will reveal any degradation, so that appropriate corrective actions may be taken to ensure that the flow orifices continue to perform as designed. All except one flow orifice are subject to periodic inspections by the procedures in the CCNPP PM program. These inspections are accomplished through Repetitive Tasks 10122095 and 20122099, which are performed every 6 years. The remaining flow orifice, which is not subject to periodic inspections, is the Unit 1 SRW heat exchanger SW emergency outlet orifice. This was installed as part of a piping modification in the 1993-1994 timeframe. Routine inspection of this orifice is not performed due to infrequent use of the flow path in which the orifice is installed. To verify that no significant age-related degradation is occurring for this orifice, the applicant committed to include it in the ARDI program.

The staff concludes that these inspections will provide adequate protection for these flow orifices against the aging effects of this ARDM and will provide reasonable assurance that all the flow orifices within the saltwater system will continue to perform their intended function in accordance with the CLB for the period of extended operation.

3.5.3.1.3 Service Water System

The applicant identified the following materials of construction in the service water (SRW) system: for piping—carbon steel; for valves—carbon steel, cast iron, stainless steel, cast brass casings, stainless steel disks and shafts; for pumps—carbon steel or cast iron casings, cast iron or bronze impeller shafts; for tanks—carbon steel; for flow elements and flow orifices—stainless steel; for radiation and temperature elements—stainless steel; for temperature indicators—carbon or stainless steel. The applicant has determined that these materials are exposed to several potential and plausible ARDMs in the SRW system. It put these ARDMs in five groups: (1) crevice corrosion/pitting, (2) erosion/corrosion, (3) general corrosion, (4) selective leaching, and (5) wear. The applicant described and evaluated the effects of each group on the materials, outlined the methods to manage aging, identified the AMPs, and demonstrated the adequacy of the proposed aging management for each of the identified ARDMs.

Section 5.17 in Appendix A to the LRA indicates that the SRW system was designed to the American National Standards Institute (ANSI) Standard B31.1 Code requirements. Although ANSI Standard B31.1 does not require an explicit fatigue analysis, it does specify allowable stress levels, based on the number of anticipated thermal cycles. Table 5.17-3 indicates that fatigue is not a plausible age related degradation mechanism for the SRW system. Although fatigue is not considered to be a plausible age related degradation mechanism as indicated in Table 5.17-3, the staff requested additional information in this area. In NRC Question No. 5.17.6, the staff requested additional information regarding the basis for concluding that fatigue is not a plausible ARDM for SRW components. In its response, the applicant indicated that the SRW system is a low-temperature system. The highest normal service condition temperature for the piping system is 130 °F. Thermal fatigue is not a plausible ARDM for the SRW piping system because the system maintains a relatively steady temperature. On the basis of the applicant's assessment, the staff agrees that thermal fatigue is not a plausible ARDM for the SRW piping system.

On the basis of industry data and experience, the staff concludes there are no other applicable ARDMs for the SRW. The following is the staff's evaluation of the AMPs for these five groups of ARDMs.

3.5.3.1.3.1 Crevice Corrosion/Pitting

The applicant has determined that long-term exposure of SRW components to the operating environment inside the system may result in crevice corrosion/pitting because sometimes these components are subjected to stagnant flow conditions, or their geometry may contain crevices. Maintaining an environment of purified water with controls on pH, oxygen, suspended solids, and chlorides during plant operation will mitigate this ARDM. Also, inspections of the SRW components in the corrosion-susceptible areas will identify whether the ARDM is actually occurring.

The CCNPP procedure CP-206 provides for monitoring and maintaining the SRW water chemistry. The PUMP-15 procedure is currently used for inspecting the SRW pumps for erosion, wear, and mechanical damage. The applicant has committed to modify PUMP-15 to include inspections of crevice corrosion/pitting of pump casings and bushings. The procedure directs the system engineer to replace damaged parts as necessary. The remaining SRW components susceptible to crevice corrosion/pitting will be included in the ARDI program aiming at verifying that the components are not degrading. The staff's reviews and evaluations of the water chemistry and ARDI programs are discussed in detail in Sections 3.1.2 and 3.1.6, respectively, of this SER.

On the basis of the mitigative effects of the water chemistry program and the additional assurance provided by the PUMP-15 procedure and ARDI, the staff concludes that these programs will provide adequate protection for the components in the SRW system against the aging effects of crevice corrosion/pitting and will provide reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.3.2 Erosion/Corrosion

Erosion/corrosion occurs in the systems containing components made of carbon steel and exposed to moving, turbulent water. In the SRW system the piping is carbon steel fabricated into straight sections, bends, and tees, a geometry that tends to create turbulent flow. Therefore, erosion/corrosion is possible. However, the internal environment of the SRW system consists of a demineralized water treated to control its oxygen level and maintain a pH above 9.0. This water remains subcooled to a temperature of 130 °F and a pressure 102 psig. On the basis of industry experience, the staff has concluded that at these operating conditions significant erosion/corrosion is unlikely.

The applicant does not credit any specific programs with mitigating the effects of erosion/corrosion in the SRW system. Therefore, the applicant will institute an ARDI program (see Section 3.1.6 of this SER) to examine representative piping which may be susceptible to erosion/corrosion. The program will include safety-related and non-safety-related portions of the system and will determine whether the piping is degraded to the point of not being capable of performing its intended function under all CLB design conditions during the period of extended operation. The applicability evaluation will also consider, at a minimum, flow rate and configuration differences between safety-related and non-safety-related SRW piping. In NRC Question No. 5.17.2, the staff requested additional information on how the flow rate and configuration differences between safety-related and non-safety-related SRW piping will be considered in the applicability evaluation and the basis upon which the applicant concluded that the results of the inspection of the safety-related piping are adequately representative of the aging degradation of the non-safety-related piping. The applicant responded on November 16, 1998, to the staff's RAI and supplemented its response on February 18, 1999, (NRC meeting summary dated March 19, 1999). The applicant stated that it will include the non-safety-related portion of piping in the same ARDI program for safety-related SRW piping that is subjected to erosion/corrosion. The applicant also agreed to document this change to the scope of the ARDI program. The staff concluded that this is an acceptable approach to resolve the RAI issue.

On the basis of multiple inspections performed under the ARDI program, the staff concludes that there is adequate protection for the components in the SRW system against the aging effects caused by erosion/corrosion and there is reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.3.3 General Corrosion

General corrosion is a plausible ARDM for certain SRW components. The corrosion can occur in the carbon steel components exposed to the service water environment and to moist compressed air in the air-operated valves. The applicant is monitoring the service water chemistry using the CCNPP procedure CP-206 for the components exposed to service water. For air-operated valves, CCNPP PM checklists IPM 10000 and IPM 10001 verify air drier effectiveness in the compressed air system to ensure that the air is dry enough to mitigate corrosion of carbon steel components in the valves. The applicant also credited its ARDI program to provide assurance that the effects of plausible ARDMs in the wetted portions of the SRW system are being effectively managed for the period of extended operation. The staff's review of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

On the basis of the mitigative effects of the water chemistry and PM programs and the additional assurance provided by the ARDI, the staff concludes that these programs will provide adequate protection for the components in the SRW system against aging effects caused by general corrosion and provide reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.3.4 Selective Leaching

The applicant has determined that control valves with cast iron bodies, pumps with cast iron casings, and hand valves with cast iron bonnets and disks, with brass bodies, or with cast brass bases and shells are susceptible to selective leaching. During selective leaching a corrosive process removes iron from the cast iron components and zinc from the brass components. If not properly managed, selective leaching may cause components to lose pressure-retaining capability under CLB design conditions.

Selective leaching can be mitigated by proper water chemistry control. The applicant's aging management program consists of controlling service water chemistry in accordance with the specifications in the CCNPP procedure CP-206 (see Section 3.1.2 of this SER). Controlling impurities and chemical additives keeps selective leaching at an acceptable level. The applicant is also committed to performing inspections of the affected components under the ARDI program (see Section 3.1.6 of this SER). The program will be able to discover any selective leaching so that proper corrective actions can be taken.

On the basis of the mitigative effects of the water chemistry program and the additional assurance provided by ARDI, the staff concludes that these programs will provide adequate protection for the components in the SRW against aging effects caused by selective leaching and provide reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.3.5 Wear

The applicant has determined that wear is a plausible ARDM for the relief valves in the SRW system. The valve bodies are made from stainless or carbon steel and have stainless steel seats and disks. Wear results from relative motion between two surfaces, from the presence of hard, abrasive particles, or from sliding motions under the influence of a corrosive environment. In addition to material loss from the wear mechanisms discussed above, impeded relative motion between two surfaces held in close contact for extended periods may result in galling or self-welding. The wear can cause damage to one or both surfaces involved in the contact, resulting in a leaking valve. The applicant will periodically conduct bench testing for relief valves that are infrequently operated or are susceptible to this ARDM to verify that the valve is not leaking or sticking. The applicant will be using the CCNPP Mechanical Maintenance Checklists MPM01013, MPM01147, MPM01153, and MPM01155 for performing these tests at 4 to 5 year intervals.

This ARDM is applicable to valve internals. As discussed in Sections 3.3.3.1 and 3.5.3.1.1.6 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and, therefore, are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.5.3.1.4 Spent Fuel Pool Cooling System

The applicant found that several plausible ARDMs applied to the spent fuel pool cooling system (SFPCS). The applicant put them in four groups: (1) general corrosion of various carbon steel components in the SFPCS; (2) rubber degradation and radiation damage of hand valve diaphragms and linings; (3) wear of hand valve seats and disks; and (4) cavitation erosion and erosion/corrosion of pump casings. The applicant evaluated the effects of each of these groups on the material of construction, identified the AMPs, and demonstrated their adequacy.

Section 5.18.1 of Appendix A to the LRA indicates that there were several instances of cracking of SFPCS piping. A detailed study was performed in early 1990 to determine the root cause and appropriate remedy. The applicant's study found that the cracking was due to high-cycle fatigue caused by cavitation-induced vibration. The sources of vibration were the SFPCS pump's recirculation line flow orifices and manual throttle valves downstream of the SFPCS heat exchangers. Subsequently, certain orifices and valves were modified to eliminate system cavitation. The applicant also indicated that since implementation of these improvements has prevented recurrence of cracking in SFPCS piping, this cracking is not considered to be a plausible ARDM. On the basis of these improvements, the staff concurs with the applicant's assessment. In NRC Question No. 5.18.5, the staff requested additional information on whether the piping is susceptible to cracking, and if the modified valves and orifices are subject to an AMR. In its response, the applicant stated that these piping components are in the scope of license renewal and are subject to an AMR. The applicant was also asked to discuss its fatigue evaluation for the SFPCS piping system. Specifically, the staff's concern is that the CCNPP UFSAR Section 9.4.3.2 states that the SFPCS piping was designed to ANSI B31.7 Code requirements. ANSI B31.7 Code specifies that requirements for Class II and III pipe design be in accordance with the ANSI B31.1 Code. Although ANSI B31.1 Code does not require an explicit fatigue analysis for Class II and III piping systems, it does specify allowable stress levels based on the number of anticipated thermal cycles. In its response, the applicant stated that the operating temperature of the SFPCS water will remain almost constant after initial refueling. Under all normal conditions, the operating temperature is less than 150 °F. This operating condition will result in many fewer equivalent full-temperature cycles than the 7000 thermal cycles assumed during the period of extended operation. Therefore, it was determined that thermal fatigue is not a plausible ARDM for the SFPCS piping system. The staff agrees with this assessment and the conclusion that thermal fatigue is not a plausible ARDM for the SFPCS piping system.

On the basis of industry data and experience, the staff concludes there are no other applicable ARDMs for the SFPCS. The following is the staff's evaluation of the AMPs for these ARDMS.

3.5.3.1.4.1 General Corrosion

All of the subcomponents included in this group are made of different varieties of carbon steel. The following subcomponents were included in this group: bolts, nuts, spent fuel pool (SFP) filter clamp assembly, SFP filter support, check and hand valve bolting, heat exchanger shell and nozzles, demineralizer support, and pump casing stud nuts. The external environment for all items in this group is climate-controlled air in the auxiliary building and in the containment. The internal environment may be either borated water with approximately 2500 ppm of boron or service water. The external surfaces of these components in this group may be exposed to a borated-water environment when boric-acid-carrying components develop a leak. Therefore, the applicant has included the components listed above in its AMR. The aging management program for these ARDMs consists of mitigating leakage of borated water. The effects of borated water on the subcomponents will be managed by the Boric Acid Corrosion Inspection (BACI) Program, which is evaluated in "Common AMPs," Section 3.1.4 of this SER. The program includes a description of the examination procedures, and actions needed to minimize loss of structural and pressure-retaining integrity of components from boric acid corrosion. Components that are installed in the areas that are normally inaccessible because of radiation levels, will be included in an ARDI program, ensuring their inspection.

The shell side of the heat exchangers of the SFPCS carry service water whose chemistry is controlled by CCNPP procedure CP-206 (see Section 3.1.2 of this SER). This ensures that the cooling water supplied to the SFPCS heat exchangers has the appropriate chemistry for minimizing corrosion. On the basis of the mitigative effects of the water chemistry program, the additional assurance provided by the BACI program, and the inspection activities performed under the ARDI program, the staff concludes that these programs will provide adequate protection for the components in the SFPCS against aging effects caused by this ARDM and provide reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.4.2 Rubber Degradation

The components in this group comprise the rubber linings and diaphragms of hand valves. These valves are exposed to borated water containing approximately 2500 ppm of boron. In addition, the diaphragms are exposed to the radiation coming from the radioactive material accumulated in the SFPCS demineralizer vessel. Rubber in lining in prolonged contact with borated water tends to blister beneath the lining and initiate corrosion of the lined surface.

No programs are credited with mitigating the effects of these ARDMs for the subcomponents in this group. The applicant credited its ARDI program (see Section 3.1.6 of this SER) to address rubber degradation in valve linings and diaphragms. The program will specify appropriate inspection techniques and methods for resolving of adverse examination findings.

This ARDM is applicable to valve internals. As discussed in Sections 3.3.3.1 and 3.5.3.1.1.6 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and, therefore, are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.5.3.1.4.3 Wear

This group includes cast or forged stainless steel (Type 304/316 or CF-3/CF-8) hand valve seats and disks for the SFPCS containment isolation valves. The internal environment is borated water containing approximately 2500 ppm of boron. Wear occurs both in components that experience considerable relative motion and in components that are held under high loads with no motion for long periods. Additionally, impeded relative motion between two surfaces held in close contact for an extended period may result in galling or self-welding. This type of wear can be discovered by inspecting and testing the valves that are susceptible to this ARDM. In addition, local leak rate testing (LLRT) of the containment isolation valves can be a useful method for detecting leakage that could be the result of wear of valve internals. CCNPP procedures STP M-571E-1 and M-571E-2, which are part of the CCNPP Containment Leakage Rate Program, address this issue. The applicant concluded that these inspections and tests will provide a basis for an aging management program that will ensure no degradation of valve design function will occur and that the valves will remain operative during the extended period of operation.

Aging Management Review

This ARDM is applicable to valve internals. As discussed in Sections 3.3.3.1 and 3.5.3.1.1.6 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and, therefore, are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

3.5.3.1.4.4 Cavitation Erosion and Erosion/Corrosion

This group includes the SFPCS pump casings and stuffing box extensions. These components are constructed of ASTM A-296, GR CA-15 steel containing 12 percent of chromium and exposed to a turbulent flow of borated water containing approximately 2500 ppm of boron. Although the applicant specified two plausible ARDMs, only cavitation erosion should be considered because materials containing 12 percent of chromium are immune to erosion/corrosion even when exposed to acidic environments.

The applicant committed to manage this ARDM using its current PM program. This program follows directives given in CCNPP PM Tasks 00672007 and 00672008, which implement Mechanical PM Checklist MPM67102, "Inspect Spent Fuel Pool Pump." This checklist contains procedures for disassembly and inspection of the pumps, which are currently performed on each pump approximately every 4 years. In the aging management program, the applicant will modify the existing procedure to explicitly reflect present inspection requirements for the SFPCS pumps. The procedure will specify inspection requirements and acceptance criteria for discovery of material loss from the SFPCS pump casing that may be caused by cavitation erosion. Using this procedure the applicant will be able to maintain SFPCS in operating conditions for the extended operation. The NRC staff agrees with the applicant's conclusion.

The staff concludes that performing the specified PM on the SFPCS pump casings and stuffing box extensions will provide adequate protection for these components against the aging effects caused by this ARDM and reasonable assurance that these components will perform their intended functions in accordance with the CLB for the period of extended operation.

3.5.3.2 Aging Management Programs

For the discussion of AMPs, refer to Section 3.5.3.1 of this SER.

3.5.3.3 Time-Limited Aging Analyses

Appendix A to the LRA states that no TLAAs apply to the cooling systems. The staff concurs with this assessment. The staff's evaluation of the applicant's identification of TLAAs is provided separately in Chapter 4.0 of this SER.

3.5.4 Conclusions

The staff has reviewed the information in Section 5.3, "Component Cooling System"; Section 5.16, "Saltwater System"; Section 5.17, "Service Water System"; and Section 5.18, "Spent Fuel Cooling System" of Appendix A to the LRA. The staff also reviewed the additional information presented by the applicant in response to the staff's RAI and the meeting on February 17, 1999, as documented by the meeting summary dated March 19, 1999. On the basis of this review as stated above, the staff concludes that the applicant has demonstrated that the aging effects associated with the cooling systems will be adequately managed so that there is reasonable assurance these systems will perform their intended function in accordance with the CLB during the period of extended operation.

3.6 Heating, Ventilation, and Air Conditioning Systems

3.6.1 Introduction

The applicant described its AMR of the heating and ventilation (H&V) systems (in the auxiliary building and primary containment) and the heating, ventilation, and air conditioning (HVAC) systems (in the control room and the diesel generator buildings) for license renewal in three separate sections of its license renewal application (LRA). These three sections are Section 5.11A, "Auxiliary Building H&V System"; Section 5.11B, "Primary Containment H&V System"; and Section 5.11C, "Control Room and Diesel Generator Buildings' HVAC System," of Appendix A to the LRA. The staff reviewed these sections of the LRA to determine whether they provided adequate information to meet the requirements stated in 10 CFR 54.21(a)(3) for managing aging effects applicable to the H&V, and HVAC systems for license renewal.

3.6.2 Summary of Technical Information in the Application

3.6.2.1 Components Subject to an Aging Management Review

3.6.2.1.1 Auxiliary Building Heating and Ventilation System

The auxiliary building H&V system consists of fans, air handling units, dampers, filters, coolers, controls, and ductwork, which provide air, in some cases filtered and tempered, to various rooms in the auxiliary and radwaste buildings. A negative pressure with respect to ambient and surrounding areas of the building is normally maintained in the auxiliary building to ensure that clean areas do not become contaminated through the ventilation system. The areas serviced by the system are the switchgear rooms (each unit), the diesel generator rooms (three total), the auxiliary feedwater (AFW) pump rooms (each unit), the service water (SRW) heat exchanger rooms (each unit), the main steam line penetration areas (each unit), the waste processing areas (each unit), the emergency core cooling system (ECCS) pump rooms (each unit), the fuel handling areas (shared between units), and general areas of the auxiliary building. Exhaust air from the waste processing areas, the ECCS pump rooms, and the fuel handling areas is passed through a roughing filter and a high-efficiency particulate (HEPA) filter to remove potentially radioactive particulate contamination before discharge through the plant vent. Exhaust air from the ECCS pump room and the fuel handling area can also be routed through separate charcoal filters to remove radioactive iodine in the event of a loss-of-coolant accident or fuel handling incident.

3.6.2.1.2 Primary Containment Heating and Ventilation System

The primary containment H&V system consists of the following subsystems:

- Containment air recirculation and cooling subsystem;
- Containment penetration room ventilation subsystem;
- Containment iodine removal subsystem;
- Hydrogen purge subsystem;
- Containment purge subsystem; and
- Control element drive mechanism cooling subsystem.

Also within the system boundary is pressure monitoring equipment for the containment and penetration room atmospheres. The pressure of the containment atmosphere is measured for post-accident monitoring and to provide signals upon high pressure for engineered safety features actuation system (ESFAS) protective actuation. Penetration room pressure is monitored to provide signals upon high pressure to isolate letdown during a loss-of-coolant accident or a letdown line rupture (high-energy line break). Containment dome temperature, containment cooler fan status, and containment hydrogen purge inside and outside containment isolation valve positions are measured for post-accident monitoring. Other monitoring equipment supports operations and testing.

3.6.2.1.3 Control Room Heating, Ventilation, and Air Conditioning Systems

Named for the control room, the control room HVAC system provides ventilation to the control room, the Unit 1 and 2 cable spreading rooms, and the Unit 1 and 2 battery rooms. The control room and cable spreading rooms are supplied by a single, year-round air conditioning system serving both units. Air handling equipment and refrigeration units are redundant, but the ductwork is not. The control room and cable spreading room areas have a third source of cooling, which is not safety-related, consisting of a water chiller supplying a second set of coils in the safety-related air handling systems. If airborne contamination occurs at the fresh air intake, a self-contained recirculation system is automatically initiated through a post-loss-of-coolant accident filter system. The control room air is then processed through HEPA and charcoal filters.

3.6.2.1.4 Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems

The applicant stated that the two new diesel generators were placed into operation at CCNPP in 1995. These diesel generators are located in two separate buildings that are dedicated for housing these diesels. The diesel generator buildings' HVAC system provides ventilation, heating, and cooling for the building spaces. Because of the unique circumstances pertaining to these HVAC systems (i.e., they were placed into service approximately 20 years after other similar HVAC systems at CCNPP, and they have a design life of 45 years), an AMR process separate and unique from that used for other plant systems and structures was used. Since aging of the existing control room HVAC system equipment is some 20 years ahead of the aging of the diesel generator buildings HVAC system equipment, and since this equipment is just at the beginning of its design life, aging management of the new equipment can be based on the future results of aging management from similar equipment groups associated with the control room HVAC system.

In Section 5.11C.1.4 of Appendix A to the LRA, the applicant explains that the newly installed HVAC system in the diesel generator building is similar to the system for the control room, and it does not need an additional AMR. However, to justify such a conclusion, the staff requested that the applicant confirm that the environmental conditions in the diesel generator building (temperature, moisture content of the air, etc.) are similar to the conditions in the control room and that the hardware configuration of the HVAC system for the diesel generator building is similar to the configuration of the control room system. This was identified as Confirmatory Item 3.6.2.1.4-1 in the previous SER.

In Attachment 2 of the submittal dated July 2, 1999, the applicant presented a comparison of the environmental conditions (inside and outside temperatures during summer and winter, and relative humidity conditions) of System 030 (Control Room HVAC) and System 103 (Emergency Diesel Generator Building HVAC). The applicant also described components and equipment types (ducting, indicators, cooling coils, fans, filters, refrigeration units, heaters, etc.) as well as construction materials and intended functions of these two systems. The staff's review of this submittal finds that the applicant has demonstrated that the newly installed HVAC system (System 103) in the diesel generator building is similar to the HVAC system (System 030) of the control room. On this basis, the staff concludes that Confirmatory Item 3.6.2.1.4-1 is closed.

3.6.2.2 Effects of Aging

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the H&V and HVAC components subject to an AMR and determined (as listed in Tables 5.11A-2, 5.11B-2, and 5.11C-2 of Appendix A to the LRA) that 21 potential ARDMs need to be considered for the auxiliary building, 26 for the primary containment, and 26 for the control room. Among these potential ARDMs, the aging effects from the following ARDMs are treated as "plausible" and should be managed for the HVAC systems associated with the auxiliary building, the primary containment, the control room, and the diesel generator buildings: crevice corrosion, dynamic loading for fans, general corrosion, pitting, wear, and elastomer degradation. In addition, the applicant identified microbiologically induced corrosion (MIC) as plausible for the primary containment and control room and radiation damage as plausible for the primary containment.

3.6.2.2.1 ARDM/Device Type Combination for an Aging Management Review

To efficiently present the results, the applicant (based on the characteristics of device types and ARDMs of the H&V and HVAC components) combined them into three ARDM/device type combination groups for the auxiliary building, five groups for the primary containment, and three groups for the control room.

The three groups for the auxiliary building are:

- Crevice corrosion, general corrosion, and pitting for duct and heat exchangers;
- Elastomer degradation and wear for non-metallic duct and damper parts; and
- Aging due to dynamic loading for fans.

The five groups for the primary containment are:

- Wear for check valves, control valves, hand valves, and motor-operated valves;
- Crevice corrosion, general corrosion, MIC, and pitting for all components exposed to moisture;
- Aging due to dynamic loading for fans;
- Radiation damage, wear, and elastomer degradation for non-metallic subcomponents; and
- Crevice corrosion and pitting for heat exchanger cooling coils.

The three groups for the control room are:

- Crevice corrosion, pitting, general corrosion, and MIC for components potentially exposed to moisture;
- Elastomer degradation and wear for non-metallic duct and damper parts; and
- Aging due to dynamic loading for fans.

3.6.2.2.2 Component Materials and Environment

Auxiliary Building

As described in Section 5.11A of Appendix A to the LRA, the duct, fittings, doors, and door hinges and latches are constructed of galvanized carbon steel. The joint angles are constructed of carbon steel and the bolts and rivets are plated carbon steel. The supply and exhaust registers are constructed of either enameled carbon steel or aluminum. At connections between fans and ducts (or casing), flexible collars (constructed of elastomer) are installed using galvanized steel bars with bolts to prevent excessive movements of ducts. All housings and fasteners for the fans are constructed of carbon steel, except for the housings for fans in the SRW heat exchanger room, which are constructed of aluminum.

With regard to the environmental condition of the auxiliary building, the applicant stated that the maximum normal relative humidities inside and outside the auxiliary building are 70 percent and 100 percent, respectively, and the temperature inside this building is in the range of 90 °F to 120 °F, except in the main steam penetration area where the temperature is around 160°F. According to the LRA, all H&V components are located in ventilated areas indoors and are not exposed to the outside weather or sunlight.

Primary Containment

As described in Section 5.11B of the LRA, the following components are constructed of carbon steel: piping, fittings, flanges, weld, the body/bonnet of hand valves and MOVs, disks of control valves, fan casings, and fasteners. The stems, disks, and seats of hand valves, check valves, and MOVs are constructed of alloy steel, stellited carbon steel or stainless steel. The stems of MOVs are stainless steel. The wedges and disks of MOVs are made of either stellited carbon steel or stainless steel. The seats of some MOVs and control valves are constructed of stellited stainless steel or ethylene propylene. At connections between fans and ducts (or casing), flexible collars (constructed of elastomer) are installed using galvanized steel bars with bolts to prevent excessive movements of ducts. The cooling coils of the heat exchangers are made of 90-10 copper-nickel.

The components mentioned above are potentially exposed to moisture or radiation or both. Some components are also exposed to the effects of dynamic loading during their operation.

Control Room

In Section 5.11C of Appendix A to the LRA, the applicant describes the materials used for constructing the HVAC system devices as carbon steel, galvanized steel, painted carbon steel, bronze, and aluminum. The seals are constructed of neoprene sponge material and the flexible collars are elastomer materials. Most of the control room HVAC system devices are constructed of carbon steel and galvanized steel. Most of the control room HVAC equipment is located in the ventilated indoor areas of the auxiliary building and, therefore, the external surfaces are not exposed to the weather or sunlight. The auxiliary building's maximum area temperature for normal operating conditions is 110 °F with a maximum relative humidity of 70 percent. Only the battery room exhaust fan and the exhaust register for the duct are exposed to the weather.

3.6.2.3 Aging Management Programs

In Tables 5.11A-3, 5.11B-3, and 5.11C-3 of Appendix A to the LRA, the applicant identified the following AMPs for the H&V and HVAC systems.

In addition to the routine maintenance programs, the applicant has established an age related degradation inspection (ARDI) program as an AMP as defined in the CCNPP IPA methodology presented in Section 2.0 of Appendix A to the LRA. According to the applicant, the ARDI program will do the following:

- Determine the examination sample size based on plausible aging effects;

- Identify inspection locations in the system/component based on plausible aging effects and consequences of loss of component intended function;

- Determine effective examination techniques (including acceptance criteria) to identify aging effects on components;

- Specify methods for interpreting examination results;

- Specify methods for resolving unacceptable examination findings, including corrective actions and consideration of design loadings required by the CLB; and

- Evaluate the need for followup examinations to monitor the progression of any age related degradation.

Corrective actions will be taken, as necessary, 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.

3.6.2.3.1 Auxiliary Building Heating and Ventilation System

Existing Programs

PM Program (PM Checklist MPM01159 with Repetitive Tasks 00322003) is to be used for the discovery and management of the effects of elastomer degradation and wear of damper seals.

Modified Existing Programs

- CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns"

  The application of this program will be credited for (a) discovery and management of the effects of crevice corrosion, general corrosion, and pitting of the external surfaces of duct and heat exchangers, (b) discovery and management of the effects of elastomer degradation and wear for the duct flexible collars, and (c) mitigation of vibration and discovery and management of the effects of dynamic loading due to fan vibration.

New Programs

- ARDI Program is to be used for (a) discovery and management of the effects of crevice corrosion, general corrosion, and pitting for the internal surfaces of duct and heat exchangers, and (b) discovery and management of the effects of elastomer degradation and wear for the surfaces of damper seals.

3.6.2.3.2 Primary Containment Heating and Ventilation Systems

Existing Programs

- CCNPP Containment Leakage Rate Testing Program
- Surveillance Test Procedures (STPs M-571I-1, M-571I-2, and M-671-1)

The combined application of these two existing programs will be credited for the discovery and management of leakage that could be the effect of (a) seating surface wear of the check valves, control valves, and motor-operated valves in the containment pressure boundary and (b) crevice corrosion, MIC, and pitting on the seat surfaces of containment isolation valves.

Existing CCNPP PM Programs

- PM Checklists MPM09150 and MPM09151 are to be used for (a) the discovery and management of the effects of crevice corrosion, general corrosion, MIC, and pitting for the containment air cooler housings, (b) the mitigation, discovery, and management of the effects of dynamic loading of the containment air cooler fans, and (c) the discovery and management of the effects of radiation damage, elastomer degradation, and wear of rubber boots for the containment air coolers.
- PM Checklists MPM04112 and MPM04197 are to be used for the mitigation, discovery, and management of the effects of dynamic loading of the containment iodine removal fans.
- PM Checklists MPM04111 (for Unit 1) and MPM09005 (for Unit 2) are to be used for the discovery and management of the effects of radiation damage, elastomer degradation, and wear of damper seals.

- PM Checklist MPM09007 is to be used for the mitigation, discovery, and management of the effects of crevice corrosion and pitting for the external surface of the containment air cooler coils.

- CCNPP Administrative Procedure MN-319, "Structure and System Walkdowns," is an existing walkdown procedure and is to be used for (a) the mitigation, discovery, and management of the effects of dynamic loading of fans outside the containment and (b) discovery and management of the effects of elastomer degradation and wear of duct flexible collars and damper seals outside the containment.

- CCNPP Chemistry Program procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems," an existing program, is to be used for the mitigation of crevice corrosion and pitting for the internal surface of the containment air cooler coils.

<u>New Programs</u>

- CCNPP ARDI program, a new program, is to be used for the discovery and management of the effects of (a) seating surface wear of hand valves, (b) crevice corrosion, general corrosion, MIC, and pitting of piping, hand valves, and MOVs, and (c) crevice corrosion and pitting of the internal surfaces of the containment air cooler cooling coils.

3.6.2.3.3 Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air Conditioning Systems

<u>Existing CCNPP Maintenance Programs</u>

- PM Checklists MPM09109, MPM09000, MPM04169, MPM09021, MPM09115, MPM09132, MPM07111, MPM09222, and EPM30700 are to be used for the discovery, and management of the effects of crevice corrosion, general corrosion, MIC, and pitting of internal surfaces of components.

- PM Checklist MPM09021 is to be used for the discovery, and management of the effects of elastomer degradation and wear of damper seals.

- CCNPP Administrative Procedure MN-319, "Structure and System Walkdowns," is a modified program and is to be used for the discovery and management of the effects of (a) crevice corrosion, general corrosion, MIC, and pitting of external surfaces of components, (b) elastomer degradation and wear of duct flexible collars, and (c) dynamic loading of fans.

New Programs

- CCNPP's ARDI program is to be used for the discovery, and management of the effects of (a) crevice corrosion, general corrosion, MIC, and pitting of internal surfaces of components and (b) elastomer degradation and wear of the seals of dampers that are not subject to routine maintenance.

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the HVAC systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.6.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-Limited Aging Analyses," of Appendix A to the LRA indicates that no time-limited aging analyses (TLAAs) apply to the H&V and HVAC systems.

3.6.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.11A, 5.11B, and 5.11C of Appendix A to the LRA regarding the applicant's programs and considered whether the effects of aging will be adequately managed during the extended period of operation of the two units of the plant. Adequate management of the effects of aging on the device types used in the H&V and HVAC systems of these buildings will ensure that the intended function of the systems will be maintained consistent with the CLB. The staff's evaluation of the licensee's LRA relative to the H&V and HVAC systems associated with the auxiliary building, primary containment, the control room, and the diesel generator buildings is discussed in the following sections.

3.6.3.1 Effects of Aging

As described in Section 3.6.2.2.2, most components (such as ducts, fittings, door hinges and latches, joint angles, bolts and rivets, piping, flanges, body/bonnet of valves, fan casings, frames, and cooling coil housings) in the H&V and HVAC systems are constructed of carbon steel and galvanized steel. As for the environmental conditions applicable to these components, the LRA stated that the maximum normal relative humidity inside and outside the buildings is 70 percent and 100 percent, respectively, and the temperature inside the buildings is in the range of 90 °F to 120 °F, except in the main steam penetration area where the temperature is around 160 °F.

The applicant listed all potential ARDMs for the H&V and HVAC systems in Table 5.11A-2 (for the auxiliary building), Table 5.11B-2 (for the primary containment), and Table 5.11C-2 (for the control room) of Appendix A to the LRA. From the ARDMs listed in these three tables, the applicant identified the following plausible ARDMs for components of H&V and HVAC systems in these three buildings: crevice corrosion, general corrosion, pitting, elastomer degradation, the effects of dynamic loading, and wear. In addition, the applicant identified MIC as a plausible ARDM for the heat exchangers in the primary containment and the control room and radiation damage as a plausible ARDM for heat exchangers in the containment. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds this approach acceptable because aging effects result from one or more ARDMs.

The LRA cited more than 20 years of operating experience as showing that the H&V and HVAC systems at CCNPP are highly reliable in maintaining their passive functions. However, the applicant identified the following aging effects: (a) some cracking in HVAC ducts because of vibration-induced fatigue, (b) loosening of some fasteners because of dynamic loading, (c) some broken damper linkages in a control room air conditioning unit, (d) some elastomer degradation of seals, and (e) corrosion in the housing below the cooling coils in some HVAC units. The LRA also stated that, other than these cases of degradation due to vibration, wear, and corrosion, no other significant aging concerns have been identified that could affect the ability of the H&V and HVAC systems and components in these three buildings to perform their passive functions. After the investigation of the cause of these aging effects, the applicant implemented corrective actions, such as installing additional duct supports and balancing fans to minimize vibration. As stated in its letter dated July 16, 1999, the applicant also took credit for the flexible collars or rubber boots which are part of the original design for minimizing vibration. In addition, the applicant modified the existing PM procedure to include lubrication of the damper linkages with the periodic visual inspection, replaced the degraded seals, and performed inspections to assess corrosion rates and the adequacy of the system pressure boundary.

On the basis of the application of the AMR methodology to the components under review, the applicant determined that the effects of corrosion (crevice corrosion, general corrosion, and pitting) for ducts and other components should be managed for license renewal. The staff agrees because the carbon steel (including galvanized steel and painted carbon steel) materials are exposed to high humidity and moisture. The applicant determined that radiation damage to and degradation of elastomer material (duct seals, flexible collars, rubber boots, etc.) and wear of non-metallic component parts (such as duct and damper parts) should be managed under license renewal. The staff agrees that the elastomer will degrade at the joints in the HVAC equipment because of relative motion between vibrating equipment, pressure variations and turbulence, and exposure to temperature changes, oxygen, moderate heat, and ozone. Also, the neoprene for the damper seals will degrade because of relative motion between the blade and sleeve during damper operation and exposure to temperature changes, oxygen, and ozone. In addition, the rubber boots on the containment air cooler (inside the containment) are exposed to radiation. All these environmental conditions will cause degradation of the material (such as reduced tensile strength, tearing, brittleness, breakdown of elastomer, etc.). The applicant determined that the effects of dynamic loading on fans from their operation, and effects of wear on the disk or ball and seat of check valves, control valves, hand valves, and MOVs should be managed under license renewal. The staff agrees because the vibration will loosen the fasteners of fans, and wear of the valve seats could impair the functioning of the valves.

3.6.3.2 Aging Management Programs

The staff focused its evaluation of the applicant's AMPs on program elements rather than on the details of plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of the program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

Scope of the Program

The staff reviewed the AMP for the H&V and HVAC system device types and concluded that it is acceptable because an appropriate scope of system structures and components of those listed in Tables 5.112A-1, 5.11B-1, and 5.11C-1 of Appendix A to the LRA is covered by the existing and modified inspection and maintenance activities.

Preventive Actions

The applicant's PM program was established to maintain plant equipment, SSCs in a reliable condition for normal operation and emergency use; to minimize equipment failure; and to extend equipment and plant life. The program covers all PM activities for nuclear power plant structures and equipment within the plant, including the H&V and HVAC system components of the auxiliary building, the primary containment, and the control room, that are within the scope of license renewal. The applicant states that guidelines drawn from industry experience and utility best practices were used in developing and enhancing this program (CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program"). However, a review of the LRA indicates that, where applicable, each of the groups identified for aging effect consideration of H&V and HVAC system device types (e.g., Group 2 in primary containment H&V system covers crevice corrosion, general corrosion, MIC, and pitting corrosion), there is a specific PM program included in MN-1-102. The staff finds the program attributes sufficient to prevent and manage aging degradation of the H&V and HVAC components.

Parameters Monitored

As described in Section 3.6.2.3 of this SER, the applicant has programs in place for inspection and identification of aging effects on the H&V and HVAC system components. The applicant has also developed an ARDI program to provide additional assurance of the availability and reliability of the system components during the license renewal period. The staff's review and evaluation of the ARDI program is discussed in Section 3.1.6 of this SER. The applicant also relies on the walkdown procedure. The staff's review of the walkdown procedure, MN-1-319, is evaluated in Section 3.1.3 of this SER. On the basis of the review of the applicant's existing program and the supplemental ARDI program, the staff concludes the applicant has developed acceptable means for inspecting and detecting aging effects on the H&V and HVAC components.

Detection of Aging, Monitoring and Trending, and Acceptance Criteria

The applicant's ARDI program includes the determination of the examination sample size based on plausible aging effects, identification of inspection locations, determination of effective examination techniques, specifications for resolving unacceptable examination findings, and evaluation of the need for followup examinations to monitor the progression of any age related degradation. The staff concludes the elements of the ARDI program related to the detection of aging effects, monitoring and trending, and procedures for resolving unacceptable results are adequate for managing the aging effects of the H&V and HVAC systems.

Corrective Actions, Confirmation Process, and Administrative Controls

The applicant indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with site-controlled corrective action programs pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program appears separately in Section 3.1.5 of this SER. On the basis of this evaluation, the staff concludes that the applicant has presented sufficient information in its LRA to show that its AMPs for license renewal satisfy the elements "corrective actions," "confirmation process," and "administrative controls."

Operating Experience

The applicant stated that from more than 20 years of operating experience of HVAC duct systems, degradations (such as cracking) of ducts from vibration, fan imbalance, loosening of fasteners, and minor corrosion of cooling coils have been experienced. The corrective actions taken were addition of supports, balancing of fans, and monitoring of corrosion rates. On the basis the operating experience described in Sections 5.11A, 5.11B, and 5.11C of Appendix A to the SER, the staff concludes that the applicant is adequately implementing corrective actions and maintenance programs of the H&V and HVAC system components.

3.6.3.3 Time-Limited Aging Analyses

On the basis of a review of the devices, their AMPs, and operating experience, the applicant has determined that no TLAAs apply to the auxiliary building and primary containment H&V systems, and control room and diesel generator building's HVAC systems. The staff agrees with this determination.

3.6.4 Conclusions

The staff has reviewed the information in Section 5.11A, "Auxiliary Building Heating and Ventilation System"; Section 5.11B, "Primary Containment Heating and Ventilation System"; and Section 5.11C, "Control Room and Diesel Generator Buildings' Heating, Ventilation, and Air-Conditioning Systems," of Appendix A to the LRA and additional information sent by the applicant in response to the staff's RAIs. On the basis of the staff's review as stated above, the staff concludes that the applicant has demonstrated that the aging effects associated with the H&V and HVAC systems will be adequately managed so that there is reasonable assurance the systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.7 Emergency Diesel Generator Systems

3.7.1 Introduction

The applicant described its AMR of the emergency diesel generator (EDG) systems for license renewal in two separate sections of its license renewal application (LRA): Section 5.7, "Diesel Fuel Oil System," and Section 5.8, "Emergency Diesel Generator System," of Appendix A to the LRA. The staff reviewed these sections of the application to determine whether they presented adequate information to meet the requirements for license renewal stated in 10 CFR 54.21(a)(3) for managing the aging effects of the EDG systems. In the course of its review, the staff sent the applicant requests for additional information concerning EDG systems and the applicant responded. In addition, several discussions were held with the applicant to discuss and resolve issues pertaining to EDG systems.

3.7.2 Summary of Technical Information in the Application

3.7.2.1 Structures and Components Subject to an Aging Management Review

Section 5.7 of Appendix A to the LRA describes the diesel fuel oil (DFO) system. The DFO system provides a reliable supply of DFO to the EDGs, the auxiliary heating boiler, the station blackout diesel generator, and the diesel-driven fire pump. The DFO system consists of two seismic Category I above-ground fuel oil storage tanks (FOSTs) and associated piping and valves. A portion of the DFO piping is buried underground. The components are constructed of carbon steel and the internal environment is DFO.

Section 5.8 of Appendix A to the LRA describes the EDG system. The EDGs are 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. The EDGs and their auxiliary supporting systems are designed to seismic Category I criteria. Because the EDGs perform their intended function with moving parts and changes in configuration, they are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i). Section

5.8 of Appendix A to the LRA addresses the EDG auxiliary supporting system components (that is, EDG fuel oil day tanks, fuel oil transfer pumps, drip tanks, drip tank pumps, starting air receivers, intake/exhaust mufflers, and intake filters). The components are primarily constructed of carbon steel and the internal environment is DFO, air, diesel engine exhaust gas, or service water.

The applicant grouped the components in the EDG systems subject to an AMR into the following device types: piping, check valves, hand valves, tanks, filters, mufflers, drain traps, wye strainers, relief valves, pumps, and accumulators. The applicant stated that these device types are required to maintain the integrity of the EDG systems.

3.7.2.2 Effects of Aging

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the components subject to an AMR. The applicant determined that the aging effects due to the following plausible ARDMs should be managed for license renewal: corrosion (crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion [MIC], and pitting), weathering, fatigue, erosion (erosion/corrosion and particulate wear erosion), and wear. Electronic searches of industry and Government indexes by the applicant indicate that cavitation corrosion, intergranular attack, stress-corrosion cracking, and thermal damage are not prevalent aging mechanisms for EDG components within the scope of license renewal. These ARDMs are not considered plausible on the basis of material used, the operating environment, and infrequent exposure to EDG high-temperature exhaust gases. The applicant's evaluation is summarized in Tables 5.7-2 and 5.8-3 of Appendix A to the LRA. Appendix A to the LRA also contains information on the operating experience of the EDG systems regarding aging degradation.

3.7.2.3 Aging Management Programs

In Appendix A to the LRA, the applicant identified the following AMPs for the EDG systems:

- CCNPP Plant Evaluation Guideline, "System Walkdowns," MN-1-319 (existing program)
- CCNPP Chemistry Program Procedure, "Oil Receipt Inspection and Fuel Oil Storage Tank Surveillance," CP-226 (existing program)
- CCNPP Plant Evaluation Program Procedure, "Operations Performance Evaluation Requirements—Drain Water from #11 and #21 FOST per OI-21," PEO-0-023-02-O-M (existing program)
- CCNPP Chemistry Program Procedure, "Determination of Particulate Contamination in Diesel Fuel Oil," CP-973 (existing program)

- Diesel Fuel Oil Buried Pipe Inspection Program (new program)
- Tank Internal Inspection Program (new program)
- Caulking and Sealant Inspection Program (new program)
- CCNPP Specification and Surveillance—Diesel Generators' Jacket Cooling System, CP-222 (existing program)
- CCNPP Surveillance Test Procedures (STP 0-8A-2, STP 0-8B-2, STP 0-8B-1) for Testing EDGs and the 4-kV LOCA Sequencers (existing program)
- CCNPP Task MPM01125, "Remove Relief Valve, Test and Reinstall" (modified program)
- CCNPP Task MPM07006, "Disassemble, Inspect and Overhaul EDG Check Valve" (modified program)
- CCNPP Task MPM13000, "Clean and Inspect EDG Air Start Distributor and Check Valves" (modified program)
- CCNPP Task MPM13002, "Inspect EDG Air Start Valves and Filters" (modified program)
- CCNPP Task MPM07117, "Inspect EDG Air Intake Filters" (modified program)
- CCNPP Tasks MPM13003, MPM13004, and MPM13005, Clean/Inspect 2B, 1B, and 2A EDG Lube Oil "Y" Strainers and Baskets (modified programs)
- CCNPP Task MPM13110, "Perform Visual Examination for EDG Exhaust Components" (modified program)
- CCNPP Age Related Degradation Inspection (ARDI) Program (new program)

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the EDG systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.7.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-Limited Aging Analyses," of Appendix A to the LRA indicated there is no time-limited aging analyses (TLAAs) applicable to the EDG systems.

3.7.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.7 and 5.8 of Appendix A to the LRA. The review was performed to ascertain that the effects of aging on the EDG systems will be adequately managed for the period of extended operation.

3.7.3.1 Effects of Aging

The operating experience information provided in Appendix A to the LRA indicates that the DFO system has, in general, performed well and has exhibited no age related degradation that impaired the system function. The applicant reported that some of the EDG components have occasionally leaked or failed to operate properly. Examples of the failure mechanisms are as follows: EDG relief valves, solenoid valves, and other components have leaked as a result of instances of wear; and general corrosion has also caused some of the EDG relief valves to stick open and check valves to stick shut as a result of buildup of corrosion products (rust) around the valve seats and disks. Although these components are active parts and are not within the scope of license a renewal AMR, it is reasonable to expect similar degradation as a result of corrosion in the components within the scope of license renewal. Cyclic fatigue has caused the failure and cracking of fuel oil injectors, check valves, tubing, and other EDG components. Corrosion and wear in the EDG air start distributors have caused the EDGs to fail some surveillances. In each case, the applicant replaced or cleaned the affected parts, and the components were successfully retested.

Several plants with Fairbanks Morse EDGs have experienced problems with degradation of welds in the skid-mounted lube oil and jacket water piping of EDGs during normal operation. Subsequent evaluation showed a significant lack of penetration and a general lack of quality in the welds, which was believed to have occurred during manufacturing. Because of this experience and because portions of the piping are subject to vibration-induced loads, the staff raised a concern regarding the potential for the failure of welds in the piping during the period of extended operation. The applicant, in its response to NRC Question No. 5.8.4 on November 4, 1998, indicated that the welds in the jacket cooling water and lube oil piping beyond the skids are included in the AMR and that these welds were evaluated as a part of the piping system. In addition, the applicant indicated that expansion joints have been provided to minimize vibration in the piping connecting to the skids. This is an acceptable explanation.

Another issue raised by the staff in NRC Question No. 5.8.5 (NRC letter to the applicant dated August 27, 1998) related to potential damage to the structures at the exit of the exhaust gases of the diesel exhaust system. Debris from these structures has the potential of blocking the diesel exhaust ducts and rendering the diesels inoperable. In its response, the applicant indicated that at CCNPP the diesel exhaust pipes are all horizontally mounted after they exit their respective diesel generator building. The diesel exhaust systems are also routed to avoid directly exposing surrounding structures to diesel exhaust gases. Therefore, because of the diesel exhaust system configuration, failures of nearby structural components affecting diesel generator exhaust gas flow are improbable. Further, during the last Unit 1 refueling outage, the original exhaust components were inspected on one of the two Unit 1 diesels. In response to NRC Question No. 5.8.6 (BGE letter to NRC dated November 4, 1998), the applicant stated that the inspections included ultrasonic measurements of the piping wall thickness and visual inspection of the muffler internals. The ultrasonic inspections indicated the piping wall thickness was greater than the minimum specification requirement of 0.25 inch. The muffler's internal surfaces were in good condition, and there was no evidence of any age related degradation. This is an acceptable explanation.

As previously described, the components in the EDG systems are constructed of carbon steel and the internal environment is DFO, air, diesel engine exhaust gas, or service water. The external environment is air, except for a portion of the DFO piping, which is buried. The applicant identified the applicable ARDMs as corrosion (crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting), weathering, fatigue (corrosion fatigue and fatigue), erosion (erosion/corrosion and particulate wear erosion), and wear. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The applicant has identified the ARDMs applicable to the EDG systems, and the applicant's evaluation of the ARDMs indicated that the ARDMs will be properly controlled and managed and, thus, should result in proper management of aging effects. The staff reviewed the applicant's evaluation of the ARDMs. The staff finds that the applicant considered a comprehensive list of ARDMs for the EDG system sufficient to identify all applicable aging effects. Listed below are the results of the staff's evaluation of the degradation mechanisms that were determined to be applicable to the EDG systems, and the staff is not aware of any additional aging effects resulting from other ARDMs that need to be considered.

3.7.3.1.1 Effects of Corrosion

The applicant determined that the effects of corrosion (crevice corrosion, galvanic corrosion, general corrosion, MIC, and pitting) should be managed for license renewal. Appendix A to the LRA addressed corrosion on external and internal surfaces of components.

3.7.3.1.1.1 Corrosion of External Surfaces

The piping material above ground in the DFO system is seamless carbon steel with forged fittings and flanges. The body and bonnet material for check valves and hand valves is cast or forged carbon steel. Alloy steel is used for valve stems and bolts. The material for the FOSTs and other EDG system components is carbon steel. The external surfaces are exposed to humid, moist, or wet environments. The effects of corrosion on the external surfaces will be mitigated by minimizing the exposure of carbon steel to the environment and protecting the surface with paint or other protective coatings. The applicant proposed structure and system walkdown inspections and PM programs to inspect for coating degradation as aging management of corrosion of the external surfaces of EDG system components for license renewal. The staff finds that there is reasonable assurance that the effects of aging will be managed because system walkdowns should be sufficient to identify any ongoing aging and to initiate corrective actions in a timely manner.

The material used for the underground piping in the DFO system is seamless carbon steel. The external surfaces of the piping are protected, in accordance with standard industry practice, with external coating and wrapping and an impressed current cathodic protection system. The applicant proposed a new program to inspect for corrosion of the buried piping in EDG systems for license renewal.

In NRC Question No. 5.7.17 (NRC letter to the applicant dated September 3, 1998), the staff requested additional information concerning the statement on page 5.7-12 of Appendix A to the LRA in which cathodic protection of external surfaces of underground piping is mentioned. A statement is made that no credit is taken for the cathodic protection program. The National Association of Corrosion Engineers (NACE) International has published Recommended Practice (RP) 01-69 (92), "Control of External Corrosion of Underground or Submerged Metallic Piping Systems," that gives guidance on the protection of underground pipelines. RP 01-69 (92) indicates that coatings and cathodic protection are to be used together. The applicant was asked to explain why the plant is not following the NACE guidance concerning cathodic protection of underground piping systems.

The applicant responded that the external surfaces of the DFO system are protected, in accordance with industry practice, with external coating and wrapping and an impressed current cathodic protection system. According to the applicant, the cathodic protection system is not within the scope of the license renewal because it does not perform any of the system intended functions defined in 10 CFR 54.4(a)(1), (2), and (3). In the previous SER, the staff disagreed with this position because cathodic protection plays a role in the protection of the piping. If the coatings are not used, the cathodic protection becomes inefficient. If the cathodic protection is not used, "holidays" in the coating may cause localized corrosion, and the pipeline may fail more rapidly than if the pipeline were not coated. The staff concluded that the applicant needs to identify both coatings and cathodic protection for buried pipelines to be within the scope of license renewal and identified this disagreement as Open Item 3.7.3.1.1.1-1.

The applicant responded to this open item in its July 2, 1999, submittal to the NRC. In its response, the applicant stated that the cathodic protection of the buried piping is provided by the non-safety-related cathodic protection system. The coatings and cathodic protection system are not within the scope of license renewal because they do not perform any of the system intended functions defined by 10 CFR 54.4(a)(1), (2), or (3). Further, evidence of coating perforation, holidays, or other damage, and evidence of pipe damage will be evaluated in accordance with the CCNPP corrective action program. The program implements the requirements of 10 CFR Part 50 (Appendix B), and contains provisions for repair or replacement, determining the root cause assessing generic implications, and establishing action to prevent recurrence.

The staff finds this response acceptable because the CCNPP corrective action program meets the requirements of 10 CFR Part 50 (Appendix B). Compliance with the requirements of 10 CFR Part 50 (Appendix B) will ensure that coating perforation, holidays, or other damage to buried piping will be minimized. On that basis, Open Item 3.7.3.1.1.1-1 is closed.

The staff reviewed the summary of the Buried Piping Inspection Program and found that the applicant's approach of identifying corrosion-related aging effects is acceptable because (1) the applicant is establishing a new program to cover the EDG system components subject to an AMR and the scope of this program includes all the buried diesel fuel oil piping; (2) although not part of the inspection program, coating, wrapping, and cathodic protection mitigate corrosion by inhibiting environmental effects; (3) the parameters monitored are the cathodic protection system parameters and coating damage observed during inspection of buried pipe sections; [The cathodic protection system parameters are (a) cleanliness of circuit breakers (annually); (b) cathodic protection tap settings and take voltage and amperage readings (monthly); and (c) cathodic protection potential profile (quarterly). Buried pipe is inspected when pipe is excavated during other maintenance, in areas with the highest likelihood of corrosion problems, and in areas with a history of corrosion problems. The locations of such inspections are based on previous inspections and such inspections are not done on a regular schedule. Selected areas of buried pipe will be inspected during the last 5 years of the current operating license term.] (4) degradation of the exterior carbon steel surfaces cannot occur without degradation of coating and wrapping and, thus, inspecting and confirming that the coating and wrapping are intact is an effective method of ensuring that corrosion on external surfaces has not occurred and the intended function is maintained; (5) effects of corrosion are detectable by visual techniques; (6) acceptance criteria ensure that any coating and wrapping degradations would be reported and evaluated according to site corrective action procedures; and (7) operating experience shows that these programs are effective. Specifically, in September 1994, the applicant excavated buried DFO system piping three times during installation of underground utilities. The applicant visually examined the coating of 2-inch and 3-inch pipe and found no degradation of the pipe. In November 1996, the applicant inspected portions of four buried DFO system pipes and found them in pristine condition after approximately 20 years of service.

The NRC staff concludes that the applicant has effective programs in place to control and manage the effects of corrosion on the external surfaces of EDG systems.

3.7.3.1.1.2 Corrosion of Internal Surfaces

The material for the fuel oil storage tanks (FOSTs) and internal components is carbon steel. The internal surfaces of the FOSTs are covered with a protective coating of a self-curing, inorganic zinc primer (trade name is Carbo Zinc 11). The tanks are normally full of oil.

Above the oil level, the surfaces of the tanks are exposed to air and fuel vapor. Corrosion occurs only when metal surfaces come into contact with fluid that may be corrosive. DFO is not corrosive to carbon steel unless water is present with the oil. Although the presence of water cannot be totally prevented, the applicant's procedures require periodic draining of water from the tanks to minimize the amount of water. Also, the applicant's chemistry program requires periodic sampling of DFO in the tanks, adding a stabilizer and a corrosion inhibitor to new fuel oil to maintain a non-corrosive environment, and adding a biocide to control microbiological activity in the FOST. The staff evaluated the aging management activities implemented by the applicant to address corrosion of the internal surface of the FOST and concluded that they were sufficient to limit the amount of corrosion of the internal surface of the FOST such that there is reasonable assurance that the effects of aging will be managed during the period of extended operation.

The applicant proposed a new program for inspecting the internal surfaces of the FOST to manage the effects of corrosion and fouling for license renewal. The application indicated that the new program will be effective because (1) the new program covers the FOST, which is subject to an AMR; (2) the FOST internal coating and controls on fuel oil quality prevent or mitigate corrosion by minimizing environmental exposure; (3) the parameter monitored is coating degradation, which is a condition directly related to potential loss of materials; (4) degradation of the interior carbon steel surfaces cannot occur without degradation of coating, and thus, inspecting and confirming that the coating is intact is an effective method of ensuring that corrosion has not occurred and the intended function is maintained; these inspections are conducted on an as-needed basis and water is drained from the bottom of the tank periodically. If more than one gallon of water is drained at a time, the situation is investigated for appropriate action; (5) effects of corrosion and coating degradation are detectable by visual and other techniques, such as those based on national codes and standards; (6) acceptance criteria ensure that significant coating degradations would be reported and evaluated according to site corrective action procedures; and (7) operating experience shows that these procedures are effective. Specifically, on November 1, 1995, the applicant inspected No. 11 FOST. The inspection revealed that the tank is in good condition and exhibits negligible coating deterioration after approximately 20 years of service. The inspection also included a series of ultrasonic tests to measure the thickness of the bottom plates. Since the coating on the tank's internal surfaces was found to be intact, there is no contact between the system fluid and the internal surfaces of the tank. The inspection found no observed deficiencies during visual (interior and exterior) inspections of the tanks, and the minimum floor thickness measurement was 0.251 inch, consistent with the original nominal thickness specification for 1/4-inch-thick plate. No corrosion was found on tank surfaces. On April 13, 1997, the applicant inspected No. 21 FOST and found it to be in similarly a good condition.

The staff finds the applicant's use of these programs acceptable because (1) this program scope includes the internal FOST shell and bottom; (2) the steel shell is painted and the tank bottom is coated with bitumastic superblack, weld seams are covered with asbestos strips, and any voids between tank bottoms and the anchor ring are filled with grout and sealed with fibrated cold plastic coal tar pitch flashing; (3) the accessible painted surfaces, caulking, and sealant are visually inspected and ultrasonic thickness measurements are taken on the tank bottom; (4) the parameters monitored are the condition of coatings, caulking, and sealants and the thickness of the tank bottom as described in CCNPP site procedures MN-1-317 and MN-3-100.

The material of the day tanks and the drip tanks is carbon steel. As previously discussed, the applicant's DFO chemistry program controls fuel oil quality; thus, corrosion of internal surfaces of these components is prevented or mitigated.

The applicant proposed inspection during the course of PM to manage the effects of corrosion of the internal surfaces of EDG system components, such as starting air and combustion air piping. The applicant also identified where existing PM programs will be modified to include the components subject to an AMR and inspection for the effects of corrosion. The staff finds this approach acceptable because (1) the applicant has programs to cover the EDG system components that are subject to an AMR; (2) an inspection program does not rely on preventive actions to preclude or slow aging effects; (3) the parameter monitored is evidence of corrosion of internal surfaces; (4) inspecting for evidence of corrosion is an effective method of ensuring that corrosion on internal surfaces has not occurred and that the intended function is maintained; (5) effects of corrosion are detectable by visual techniques and inspections are periodic (every 2 to 4 years) and should provide for timely detection of aging effects on the basis of operating experience; (6) acceptance criteria ensure that any evidence of corrosion would be reported and evaluated according to site corrective action procedures; and (7) operating experience shows that these programs are effective on the basis of the degradation found and the corrective action taken.

The applicant also indicated that it has a program for controlling the corrosive effects of jacket cooling water in the EDG. The program is controlled by CCNPP Chemistry Procedure CP-222, "Specifications and Surveillance for Diesel Generators' Jacket Cooling Water Systems." This procedure has two sets of chemistry parameters: one for treated water containing hydrazine, which is used as a cooling medium for the Fairbanks Morse EDGs, and the other for demineralized water containing ethylene glycol, which constitutes a cooling medium for the SACM EDGs. The procedure describes the surveillance and specifications for monitoring jacket water. It also lists parameters to be monitored and the target and action levels for the EDG jacket cooling water parameters. These parameters are currently monitored on a frequency ranging from once a week to once a year. The staff concurs that with these actions the applicant will ensure that the effects of general corrosion, crevice corrosion, and pitting, to which the components in the EDG jacket cooling water systems are exposed, will be minimized. Also, the jacket water expansion tank will be included in an ARDI program that will be responsible for inspection of other EDG components, such as cooling water piping, starting air system hand valves, and cooling water hand valves. The staff's review of the ARDI program is discussed in Section 3.1.6 of this SER in which the staff concluded that the applicant presented enough information in Appendix A to the LRA to show that the ARDI program is an effective AMP for detecting corrosion damage in the systems mentioned above.

The NRC staff concludes that the applicant has an effective program for controlling and managing the effects of corrosion on the internal surfaces of EDG systems.

3.7.3.1.1.3 External Exposed Surfaces of the FOST Shells and Bottoms

Appendix A to the LRA indicated that the FOST bottoms are not subject to any applicable aging effects. The applicant's basis for this conclusion is that the tank bottoms are coated, set on oil-soaked soil, sealed with grout, and protected by cathodic protection. In NRC Question No. 5.7.19 (NRC letter to the applicant dated September 3, 1998), the staff asked the applicant to provide information concerning the applicable aging effects on the FOST bottoms that may be in contact with soil and to describe the AMP for license renewal. Specifically, the staff referred to National Associate of Conosion Engineers (NACE) Standard RP 0193 (93), "External Cathodic Protection of On-Grade Metallic Storage Tank Bottoms," for managing aging effects on FOST bottoms. The applicant responded that Procedure MN-1-319, "Structure and System Walkdowns," which is used to discover age related degradation of the external surfaces of the FOST shell. Furthermore, operating experience, combined with the results of ultrasonic examinations, indicates that the FOST bottoms are not corroding. On this basis, the staff agrees that the FOST shell requires no additional aging management.

3.7.3.1.2 Effects of Weathering

The applicant determined that the effects of weathering should be managed for the sealants and caulking of the FOST perimeter seal. Caulking and sealants do not contribute to the intended function of the tank. However, they play a role in mitigating corrosion of the tank bottom by preventing moisture intrusion. Because the caulking and sealants are susceptible to degradation, the applicant proposed a new caulking and sealant inspection program, which will be covered by the structure and system walkdown inspections, to visually inspect and probe caulking and sealants for degradation at periodic intervals (monthly as specified in MN-1-319 or as determined by the results of previous inspections) as aging management of the caulking and sealants for license renewal. The staff finds this practice acceptable because (1) the applicant has a program to cover the caulking and sealing of the FOST perimeter seal; (2) caulking and sealants have a role in preventing or mitigating moisture intrusion into the tank bottom to minimize environmental exposure; (3) the parameters monitored are attachment of the caulking and sealants to the bonding surfaces and flexibility of the caulking and sealants, which relate to their ability to keep moisture out of the tank bottom; (4) observing and confirming the condition of the caulking and sealants is an effective method of minimizing environmental exposure of the tank bottom; (5) weathering degradation of caulking and sealants is detectible by visual techniques and physical probing; (6) acceptance criteria ensure that loss of attachment to bonding surfaces and flexibility are reported and evaluated according to site corrective action procedures; and (7) operating experience shows that such caulking and sealant inspection programs are effective in monitoring and managing weathering degradation of these materials. Therefore, the caulking and sealant inspection program is adequate to control the effects of weathering.

The NRC staff concludes that the applicant has an effective program for controlling and managing the effects of weathering on the EDG systems.

3.7.3.1.3 Effects of Fatigue

The applicant determined that the effects of fatigue (corrosion fatigue and fatigue) should be managed for the EDG exhaust piping and muffler components. The applicant proposed inspection during the course of PM and a new inspection program to manage fatigue for these components for the period of extended operation. Appendix A to the LRA indicated that PM programs and the new inspection program would detect the effects of fatigue on the external and internal surfaces, respectively, of the components. The NRC staff agrees with the applicant that an inspection program to manage the fatigue of EDG exhaust piping and exhaust muffler components would ensure that the effects of fatigue are minimized and managed.

The NRC staff concludes that the applicant has an effective program for controlling and managing the effects of fatigue on the EDG systems.

3.7.3.1.4 Effects of Erosion

The applicant determined that EDG cooling water piping and exhaust muffler components are subjected to erosion mechanisms as a result of erosion/corrosion and particulate wear mechanisms. Erosion/corrosion affects carbon steel components in contact with high-velocity single- or two-phase water that has regions of disturbed flow, low oxygen content, and a pH less than 9.3. Since these conditions may occur in the pipes carrying service water used for cooling EDG jacket cooling water, erosion/corrosion is a plausible ARDM. Because the internal environment in the EDG exhaust mufflers experiences periodic exposure to hot diesel gases that contain moisture and entrained particles, the carbon steel components in this system are subjected to both erosion/corrosion and particulate wear mechanisms. Particulate wear is caused by mechanical abrasion from the presence of particles in the high-temperature fluid (liquid or gas) moving with high velocities relative to the affected components. Because hot exhaust gases may erode certain portions of the muffler during EDG operation, an ARDM could possibly occur. The applicant has no specific AMPs that could be credited with mitigation of erosion/corrosion or particulate wear erosion. However, inspection under the proposed ARDI program will provide for the discovery of loss of materials as a result of these effects so that appropriate corrective action could be taken. The staff's review of the ARDI program is discussed in detail in Section 3.1.6 of this SER in which the staff concluded that the applicant presented enough information in Appendix A to the LRA to show that the ARDI program is an effective AMP for detecting these damage mechanisms in the above-mentioned EDG systems mentioned above.

In view of the preceding discussion the NRC staff concludes that the applicant has an effective program for controlling and managing the effects of erosion on the EDG systems.

3.7.3.2 Aging Management Programs

The staff evaluated the applicant's AMPs as discussed above to determine whether the following programs will provide adequate aging management for the EDG components:

(1) Diesel Fuel Oil Buried Pipe Inspection Program (new program)

(2) Tank Internal Inspection Program (new program)

(3) Caulking and Sealant Inspection Program (new program)

(4) CCNPP Age Related Degradation Inspection (ARDI) Program (new program)

The staff finds these AMPs acceptable for managing the aging associated with the EDG components.

3.7.3.3 Time-Limited Aging Analyses

Appendix A to the LRA indicated that there are no TLAAs applicable to the EDG systems. The staff's evaluation of the applicant's identification of TLAAs appears in Chapter 4 of this SER.

3.7.4 Conclusions

The staff has reviewed the information in Section 5.7, "Diesel Fuel Oil System," and Section 5.8, "Emergency Diesel Generator System," of Appendix A to the LRA, and the additional information sent by the applicant in response to the staff's RAIs. On the basis of this review, as previously stated, the staff concludes that the applicant has demonstrated that the aging effects associated with the EDG systems will be adequately managed so that there is reasonable assurance the EDG systems will perform their intended function in accordance with the CLB during the period of extended operation.

3.8 Steam and Power Conversion Systems (SPCSs)

3.8.1 Introduction

The applicant described its AMR of the SPCSs for license renewal in the following three sections of Appendix A to the LRA: Section 5.1, "Auxiliary Feedwater (AFW) System "; Section 5.9, "Feedwater (FWS) System"; and Section 5.12, "Main Steam, Steam Generator Blowdown, Extraction Steam, Nitrogen and Hydrogen System." The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the steam and power conversion systems will be adequately managed during this period of extended operation as required by 10 CFR 54.21(a)(3). In the course of its review, the staff sent the applicant RAIs concerning these systems and the applicant responded. Additional information was obtained from the applicant during meetings held to discuss and resolve issues pertaining to these systems.

3.8.2 Summary of Technical Information in the Application

3.8.2.1 Structures and Components Subject to an Aging Management Review

Section 5.1 of Appendix A to the LRA described the AFW system, which is designed to provide emergency water from the No. 12 condensate storage tank (CST) to the steam generators (SGs), to remove sensible and decay heat, and to cool the primary system to 300 °F if the main condensate pumps or the main feedwater pumps are inoperative. Three AFW pumps are installed in each unit, consisting of one motor-driven and two non-condensing steam turbine-driven pumps. Other major components of the AFW system are blocking valves, flow control valves, check valves, turbine steam isolation and governor valves, flow elements, and associated piping, instrumentation, and controls.

The applicant determined that the following device types require an AMR: piping, check valves, governor valves, hand valves, pressure control valves, solenoid valves, flow elements and orifice, current/pneumatic device, pump, tank, and turbine.

Section 5.9 of Appendix A to the LRA described the feedwater system. The FWS which transfers condensate received from the condensate system to the SGs, raises the temperature of the feedwater to increase plant efficiency, and controls the rate of flow to the SGs to match the steam flow demand by the plant turbine generators. The major components of the FWS are piping, steam-driven pumps, high-pressure feedwater heaters, regulating valves, isolation valves, header check valves, and SG secondary-side pressure and level instrumentation loops.

The applicant determined that the following device types require an AMR: piping, valves (check valves, hand valves, MOVs), and temperature elements.

Section 5.12 of Appendix A to the LRA, described the main steam, SG blowdown, extraction steam, and nitrogen and hydrogen systems in detail. Specifically, the main steam system provides steam to the plant turbines. The steam is generated in the SGs and the steam flows through a main steam header from each SG to the main turbine high-pressure stop valves. The extraction system provides extraction steam, which is used to increase the temperature of the feedwater before it enters the SGs. Wet steam is directed from three highest stage pressure feedwater heaters in the condensate and feedwater systems en route to the heater drain tanks. Wet steam from the three lowest stage pressure feedwater heaters is cascaded to the previous stage feedwater heater and eventually recovered in the condenser. The hydrogen and nitrogen systems consist of two independent systems supplying gases for normal plant operations. The applicant determined that the following device types require an AMR: piping, accumulators, valves (check valves, hand valves, and MOVs), encapsulation, flow elements and orifices, heat exchangers, current/pneumatic devices, temperature elements, and tanks.

3.8.2.2 Effects of Aging

The applicant evaluated the applicability of ARDMs for the components subject to an AMR. The applicant determined that the aging effects from the following "plausible" ARDMs should be managed for license renewal: cavitation erosion, general corrosion, crevice corrosion, pitting, erosion/corrosion, wear, selective leaching, elastomer degradation, and fatigue. A description of these ARDMs by system follows.

Auxiliary Feedwater System

For this system, the applicant grouped the components into the following nine device types with their respective ARDMs:

- Group 1—cavitation erosion of AFW piping;
- Group 2—internal surface corrosion of piping, motor-driven AFW pumps, and valves in a water environment;
- Group 3—external surface corrosion of piping, valves, and tanks in an atmospheric environment;
- Group 4—external surface corrosion of buried pipe;
- Group 5—internal surface corrosion of the governor valve, turbine, and control valve (turbine throttle/stop valves 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.

A more detailed description of the component materials, environments, and ARDMs follows:

- Group 1—Cavitation Erosion of AFW Piping

  Cavitation erosion is a flow-sensitive degradation mechanism that occurs in piping where severe discontinuities in flow path exist, such as proximity to pump, throttle valve, reducing valve, or flow orificies.

The pipe and fitting material for the AFW piping is carbon steel. The bolting materials are alloy steel and 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.

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 may result in cavitation at these locations.

- Group 2—Internal Surface Corrosion in a Water Environment

  Group 2 consists of components in an internal environment of treated water and whose internal surfaces are subject to crevice corrosion, general corrosion, and/or pitting. The device types are piping, motor-driven AFW pumps, and valves. The materials are carbon steel, alloy steel, and stainless steel.

- Group 3—External Surface Corrosion in an Atmospheric 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 are piping, valves, and tanks made of carbon steel, alloy steel, and stainless steel.

- Group 4—External Surface Corrosion of Buried Pipe

  Group 4 consists of piping that is buried in soil or embedded in concrete and whose external surfaces are subject to crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion (MIC), and pitting. The buried pipe and fittings are carbon steel.

- Group 5—Internal Surface Corrosion in a Steam Environment

  Group 5 components are exposed to an internal environment of chemistry-controlled steam below 600 °F, and are subject to crevice corrosion, general corrosion, pitting, and erosion/corrosion. The device types are the governor valve, turbine, and control valve (turbine throttle/stop valves). The subcomponents in these device types are made of the following materials: alloy steel, chromium-molybdenum steel, carbon steel, and stainless steel.

- Group 6—External Surface Corrosion of the Turbine-driven Pump

Group 6 consists of the external surfaces of the turbine-driven pump that are subject to crevice corrosion and pitting caused by stuffing box leakoff. The material is stainless steel.

- Group 7—Wear and Elastomer Degradation of Solenoid-operated Valves

  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 internal surfaces of the solenoid-operated valves are exposed to compressed air, which is normally clean of debris, oil-free, and dry.

- Group 8—General Corrosion of Control Valve Operators

  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 materials are carbon steel (some zinc-plated), cast iron, brass, and bronze.

- Group 9—Elastomer Degradation of No. 12 CST Perimeter Seal

  The No. 12 CST perimeter seal is a caulking material consisting of an elastomer. The elastomer is protected from the direct effects of the weather by the stainless steel tank's protective enclosure.

Operating Experience

The applicant stated that the AFW system has not had significant aging-related problems over its 20-year history. In 1991, the applicant discovered evidence of corrosion in Unit 2 AFW pumps. The applicant attributed the presence of corrosion to the extended plant outage, which began in 1989. The applicant has established a schedule to overhaul AFW pump turbines every 10 years. The applicant's inspections of AFW pump turbines during overhauls have revealed no defects such as cracks or corrosion. They showed that the AFW pump turbines are in good condition. The AFW turbine-driven pumps are overhauled every 4 years.

<u>Feedwater System</u>

For this system, the applicant grouped the components into the following three device types with their respective ARDMs:

- Group 1—crevice corrosion, general corrosion, and pitting for all components subject to an AMR.

- Group 2—low-cycle fatigue for the horizontal run of piping adjacent to the SG.

- Group 3—erosion/corrosion for piping, check valves, MOVs, and temperature elements.

A more detailed description of the component materials, environments, and ARDMs follows:

- Group 1—Crevice Corrosion, General Corrosion, and Pitting for All Components Subject to an AMR

  The internal environment for the Group 1 FWS components during power generation is chemically treated, demineralized, high-pressure water that increases in temperature with plant power level from 100 °F or less to approximately 435 °F at full power. System flow rates and fluid velocities are high at full-power conditions. During all normal modes of plant operation, the system bulk fluid is subcooled water. During plant shutdown conditions, the system may be drained or may be maintained completely filled with water.

  The materials of the components are carbon steel and chromium molybdenum steel.

- Group 2—Low Cycle Fatigue for the Horizontal Run of Piping Adjacent to the SG

  Group 2 consists of the large-bore FWS main line piping of carbon steel, and the small-bore drain and instrument tap piping of carbon steel with forged fittings.

  The internal environment for the FWS piping during power generation is chemically treated, demineralized, high-pressure water that increases in temperature with plant power level from 100 °F or less to approximately 435 °F at full power. Plant transients subject the FWS to thermal stress during plant heatups, plant cooldowns, and plant trips. The horizontal segment of FWS piping adjacent to the SG inlet nozzle is also subject to thermal stratification during hot standby and at power levels less than 10 percent. At low power levels, the feedwater flow rate can vary, resulting in rapid shifts in the stratified layers, thereby causing temperature changes in the piping. Thermal stratification has resulted in measured top-to-bottom temperature differences of up to approximately 420 °F.

- Group 3—Erosion/Corrosion for Piping, Check Valves, MOVs, and Temperature Elements

  The materials and environment discussion for Group 1 encompasses all materials and environments for this group.

Operating Experience

The applicant has found the FWS to be a reliable system since plant startup. It identified some aging concerns through operating experience at the plant as well as through monitoring of industry activities. For example, erosion/corrosion discovered in the main steam system has led to its discovery in the FWS. The applicant stated, however, that no age related degradation has occurred that has prevented the components from performing their intended functions.

Main Steam, Steam Generator Blowdown, Extraction Steam, Nitrogen, and Hydrogen Systems

The applicant grouped the device types and ARDMs for these systems as follows:

- Group 1—crevice corrosion, general corrosion, and pitting for all device types;
- Group 2—erosion/corrosion and cavitation erosion of piping and erosion/corrosion of flow orifices, valves (check valves, control valves, hand valves, MOVs), and heat exchangers;
- Group 3—the selective leaching of the SG blowdown radiation monitor cooler; and
- Group 4—the wear within control valves.

A more detailed description of the component materials, environments, and ARDMs follows.

- Group 1—Crevice Corrosion, General Corrosion, and Pitting for All Device Types

  For Group 1 components, the materials are carbon and alloy steels.

  The internal environment for the main steam system and its components during power generation is saturated steam at a design pressure/temperature of 1000 psig/580 °F and normal operating parameters of approximately 850 psig/520 °F. During normal operation, between test actuations of the AFW system, the main steam lines to the AFW pumps will experience significant condensation of residual steam and two-phase flow through the main steam drains.

  The portion of the extraction steam system that is within the scope of license renewal is the piping that penetrates the containment to provide a reactor head washdown function. This function is not used; therefore, this piping is usually empty except when subjected to the presence of testing air.

  The nitrogen system has design conditions of 300 psig/150 °F, although it can also contain testing air.

  The internal environment for the SG blowdown piping is one of a saturated mixture of steam and feedwater that is subcooled to water via the blowdown heat exchangers.

  The internal environment for the instrument air piping is air that has been dried to a dewpoint of -40 °F with design operating conditions of 125 psig/100 °F.

- Group 2—Erosion/Corrosion and Cavitation Erosion of Piping and Erosion/Corrosion of Flow Orifices, Valves, Heat Exchangers, and MOVs

  The components and materials affected by erosion/corrosion are the main steam piping; the main steam drains piping; the SG blowdown piping; the non-regenerative SG blowdown heat exchanger tubesheets and tubesheet nozzle necks, heads, and flanges; the inlet and safe ends of the SG flow venturis; main steam drain check valves; main steam to AFW pump check valves; main steam to AFW pump isolation control valves; hand valves for the main steam atmospheric dump valves and the steam supply to the AFW pumps; and the main steam drain MOVs. The SG blowdown piping, in addition to being affected by erosion/corrosion, is also affected by cavitation erosion. All of these components are fabricated of carbon steel.

  In addition to these components, the following components are also affected: the main steam system atmospheric dump valves, which are carbon steel with stainless steel stems, seats, and plugs; and the main steam isolation valves (MSIVs), which are carbon steel with stellited seating surfaces.

  The environment discussion for Group 1 also applies to the systems and components included for this group.

- Group 3—The Selective Leaching of the SG Blowdown Radiation Monitor Cooler

  The only component affected by this ARDM is the SG blowdown radiation monitor cooler, which has brass and cast iron components. The shell-side environment is SG blowdown, which could be a two-phase mixture of steam and water upon entry into the cooler. The tube-side environment is component cooling water (CCW) system.

- Group 4—The Wear Within Control Valves

  The only components affected by this ARDM are the stainless steel seats and plugs of the steam atmospheric dump valves and the stellited carbon steel bodies and disc assemblies of the MSIVs. The environment for these valves is the same as that in the main steam system, as described under Group 1 above.

Operating Experience

Operating experience pertinent to aging of the components in the systems included in the LRA indicated that several modifications were required. The applicant replaced several system valves, including MSIVs because of reliability concerns. The applicant initiated inspection of these valves every 4 years under the PM program. The applicant also improved condensed fluid draining in the auxiliary feedwater pumps to keep impinging water droplets from damaging the turbine governor. Failure of some extraction piping due to erosion/corrosion, although not in the systems within the scope of the LRA, prompted establishment of an erosion/corrosion program, which proved to be very useful in controlling erosion/corrosion in the components within the LRA. The applicant also replaced blowdown system piping inside the containment, within the scope of the LRA, with new carbon steel piping with bends instead of elbows. The bends provide a better design in an erosion/corrosion environment. In addition, the carbon steel elbows in the blowdown piping at the SGs were replaced with chromium-molybdenum elbows, which are more resistant to erosion/corrosion. As more piping is identified for replacement, the applicant plans to replace it with piping that is resistant to erosion/corrosion.

3.8.2.3 Aging Management Programs

The applicant identified the following AMPs for the systems mentioned above:

- 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")
- CCNPP Secondary Chemistry Specifications and Surveillance Program (Procedure CP-217, "Specifications and Surveillance: Secondary Chemistry")
- CCNPP System Walkdown Program (CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns")
- CCNPP PM Program (CCNPP Maintenance Program Procedure MN-1-102, "Preventive Maintenance Program")
- Repetitive Tasks 10191024 and 20191022, "Check Instrument Air Quality at System Low Points" (IPM10000 and IPM10001)
- Repetitive Tasks 10362000, 10362001, 20362018, 20362019 using procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul" and procedure VALVE-28, "Auxiliary Feedwater Pump Turbine Governor Valve Overhaul."
- ARDI Program
- AFW Buried Pipe Inspection Program
- CCNPP Erosion/Corrosion Program Procedure, "Erosion/Corrosion Monitoring of Secondary Piping," MN-3-202
- CCNPP Fatigue Monitoring Program Procedure, "Implementation of Fatigue Monitoring," EN-1-300

- CCNPP Evaluation of the Thermal Fatigue Effects on Systems Requiring AMR for License Renewal
- CCNPP Chemistry Program Procedure CP-206, "Specifications and Surveillance for Component Cooling/Service Water Systems"
- MSIV-4; PM Repetitive Tasks 10832098, 10832099, 20832089, and 20832090
- PM Repetitive Tasks 10832067, 10832068, 20832062, and 20832063

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the subject systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.8.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-limited Aging Analyses," of Appendix A to the LRA indicated that the fatigue analysis is a time-limited aging analysis (TLAA) for the main steam system supply lines to the auxiliary feedwater pump turbines. In addition, the staff considers the applicant's assessment of the number of thermal cycles expected for the AFW and FW piping to be TLAAs.

3.8.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.1, 5.9, and 5.12 of Appendix A to the LRA. The purpose of the review was to ascertain that the applicant has adequately demonstrated that effects of aging will be adequately managed so that the intended function of the systems will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER. In the course of its review, the staff transmitted to the applicant RAIs concerning the subject systems and the applicant responded to these RAIs. Additional information was obtained from the applicant during meetings held to discuss and resolve issues pertaining to subject systems.

3.8.3.1 Effects of Aging

3.8.3.1.1 Corrosion, Erosion/Corrosion, Cavitation Erosion, Wear, and Elastomer Degradation

The applicant identified erosion/corrosion and cavitation erosion as plausible ARDMs for components made of steel and exposed to steam, air, and water. The staff agrees because these ARDMs are known to occur under the environmental conditions present.

The applicant identified various types of internal and external surface corrosion of devices made of steels in water, air, steam, and buried underground. The staff agrees because these materials are susceptible to corrosion when exposed to moisture found in these four environments.

The applicant identified wear and elastomer degradation of solenoid-operated valve seats, general corrosion of control valve operators, and wear in control valves as plausible ARDMs. The staff did not evaluate the applicant's AMR of these internals components because they perform their intended function with moving parts and changes in configuration, and are not subject to an AMR pursuant to 10 CFR 54.21(a)(1)(i).

The applicant identified elastomer degradation of a perimeter seal as plausible ARDMs. The staff agrees because elastomers are subject to degradation over time in air.

3.8.3.1.2 Fatigue

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity because of metal fatigue, which results in the initiation and propagation of cracks in the material. The fatigue life of a component is a function of its material, the environment, and the number and magnitude of the applied cyclic loads. The applicant addressed low-cycle fatigue for the FWS. According to the applicant, there have been no fatigue failures in the FWS at CCNPP. However, cracking has been reported in the feedwater piping at other facilities. Therefore, the applicant evaluated the FWS for low-cycle fatigue.

The staff reviewed the information regarding fatigue of the FWS components contained in Section 5.9 of Appendix A to the LRA for compliance with the provisions specified in 10 CFR 54.21(a)(3). By letter dated September 1, 1998, the staff requested additional information regarding the fatigue assessment of the FWS piping. The applicant responded to the staff's RAI by letter dated November 16, 1998.

The applicant discussed two methods to mitigate the effects of low-cycle fatigue for the FWS. One method is to reduce the number and severity of thermal transients. The other method is to replace the affected piping components. The most significant FWS thermal transients occur during plant heatup and cooldown, during hot standby, or at operation at less than 10 percent power. According to the applicant, plant operators minimize the length of transitory operations as part of general operating practice.

The applicant indicated that plant operational transients apply cyclic thermal loads to the FWS piping within the scope of license renewal. The typical transients of concern for the piping are FWS heatups, cooldowns, and secondary plant transients. The design code for the FWS piping is USAS (ANSI) B31.7, Class II, which references the design criteria in USAS (ANSI) B31.1. The criteria for USAS B31.7, Class I piping contain specific provisions for the detailed evaluation of fatigue usage resulting from local thermal transient stresses. USAS B31.1 does not require a detailed fatigue analysis evaluation of local thermal stresses. Instead, USAS B31.1 controls fatigue by limiting the allowable range of bending stresses resulting from the restraint of free-end expansion of the piping. The criteria also specify a reduction in the allowable stress range if the number of cycles exceeds 7000 full-range stress cycles. According to the applicant, the total number of expected thermal cycles resulting from expected plant transients through the extended period of operation for the FWS is well below the 7000 limit specified in the USAS B31.1. Therefore, the applicant concluded that, except for the horizontal section of piping leading to the SG FW nozzle, low-cycle fatigue is not a concern for the FWS piping. The staff agrees with the applicant's assessment.

The potential and plausible ARDMs for the AFW system are identified in Table 5.1-2 in Section 5.1 of Appendix A to the LRA. However, components such as the AFW piping, pumps, and valves are considered to have low susceptibility to fatigue. In NRC Question No. 5.1.4, the staff asked the applicant to describe the evaluation and any specific criteria that the applicant utilized in order to conclude that fatigue is not a plausible aging effect for the AFW components. Inasmuch as corrosion and pitting have been identified as plausible aging effects for the AFW components, the applicant was asked to include in its response a discussion related to the effects of the degradation caused by corrosion and pitting on the structural integrity of the components, and the basis for excluding fatigue as a plausible aging effect.

The applicant, in its response, stated that there are no steam piping segments within the scope of license renewal for the AFW system. Steam is delivered to the control valves via the main steam system. In Section 5.12 of Appendix A to the LRA, "Main Steam," the applicant addressed this steam supply piping. Exhaust steam piping from the AFW turbines to the roof exhausts is not within the scope of license renewal.

The applicant further indicated in its response that fatigue is not plausible for the control valves, steam turbine, and governor valves, which have an internal environment of steam. The subject components are in a piping system that is designed in accordance with ANSI B31.1. The piping system design analysis includes an implicit fatigue design basis. A detailed fatigue analysis is performed only for Class 1 components, unless special concerns exist. Special concerns may include the presence of thermal stratification or other conditions that the original design did not consider. The applicant has not identified any special concerns for these components. The manufacturer has indicated that 2204 individual thermal cycles are available before exceeding the theoretical thermal fatigue life. The number of thermal cycles for these components over a 60-year period is conservatively estimated to be 1480 cycles.

The applicant also indicated that fatigue is not considered plausible for AFW components in the liquid flowpath between the CST and the SGs. The majority of the system in the liquid flowpath between the CST and the SGs has an operating temperature of 100 °F or less. The portion of piping adjacent to the SG nozzles experiences higher temperatures and is normally stagnant. This results in a gradual temperature gradient between the SGs' nozzles and the upstream AFW piping. The pipe is 4 inches in diameter with a wall thickness of 0.337 inch and no significant thermal stresses during heatup or cooldown are anticipated. CST water at 40°F–100 °F is delivered through these lines infrequently, e.g., during tests. This is not expected to introduce thermal stresses.

Additionally, components in the AFW liquid flowpath between the CST and the SGs were evaluated in an AFW system fatigue analysis. On the basis of the evaluation, the applicant determined that the most fatigue-limiting components in this flowpath were the check valves immediately upstream of the SGs. The fatigue analysis calculated the cumulative usage factor (CUF) for these check valves as 0.041. The CUF is based on 400 cycles of AFW initiation for each SG. The temperature differential was conservatively assumed to be 532 °F on the SG side of the check valve, with 32 °F AFW water injection. The analysis demonstrates that the CUFs for these check valves, the piping between these check valves and the SGs, and all other upstream components will be far below the limiting CUF value of 1.0 for the 60-year projected period of operation. Therefore, the applicant concluded that fatigue is not plausible for this system. On the basis of the preceding discussion, the staff agrees with the applicant's conclusion.

The applicant described its AMR of the main steam generator blowdown system, extraction steam system, and the nitrogen and hydrogen systems in Section 5.12 of Appendix A to the LRA. The staff reviewed that section of the application to determine whether it meets the requirements stated in 10 CFR 54.21 (a)(3) for managing aging effects of these systems for license renewal.

Section 5.12.1.1 of Appendix A to the LRA describes the main steam system. All components of the main steam system evaluated in this section of the LRA are seismic Category 1 and are subject to applicable loading conditions identified in UFSAR Section 5A.3.2 for seismic Category 1 systems and equipment design. According to the applicant, the main steam system piping from the SG to the containment penetration is designed in accordance with the American National Standards Institute (ANSI) Standard B31.1 Code requirement (see Appendix B of this SER). From the penetration to the MSIVs, the piping meets the design requirements of ANSI B.31.7, Class II, Nuclear Power Piping Code. The steam supply piping to the AFW pumps is designed in accordance with the ANSI B.31.1 Code requirement. The SG blowdown piping is designed to ANSI B31.7 (for containment penetration piping) and ANSI B31.1 (for non-penetration piping) code requirements. The extraction steam piping within the scope of license renewal is the containment penetration piping for reactor vessel head washdown. The piping is designed in accordance with ANSI B31.7. The nitrogen and hydrogen system piping within the scope of license renewal, is the nitrogen penetration piping and the nitrogen piping to the SGs via the surface blowdown piping. The nitrogen penetration piping is designed in accordance with ANSI B31.7 and the nitrogen piping to the SG is designed in accordance with ANSI B31.1.

Table 5.12-4 in Appendix A to the LRA shows a list of potential and plausible ARDMs for the device types subject to an AMR. It indicates that fatigue is not a plausible ARDM for the main steam system. In NRC Question No. 5.12.10, the staff requested additional information regarding the basis for concluding that fatigue is not a plausible ARDM for the main steam system. In its response, the applicant indicated that the main steam piping fatigue is one of the time-limited aging analyses that were determined to be subject to license renewal review. In Section 2.1.3.4 of Appendix A to the LRA, the applicant discussed the basis for concluding that the main steam piping fatigue analyses meet the criteria of 10 CFR 54.21(c)(1)(i). The applicant stated that 7000 assumed thermal cycles will not be exceeded during the period of extended operation. Since the main steam system is designed to withstand a much larger number of thermal cycles than it will actually experience through the period of extended operation, the applicant determined that the thermal fatigue is not a plausible ARDM for the main steam system. The staff agrees with the applicant's assessment and the conclusion that thermal fatigue is not a plausible ARDM for the main steam system.

3.8.3.2 Aging Management Programs

The staff focused its evaluation of the applicant's aging management program on the following 10 elements constituting an adequate aging management program for license renewal: program scope, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The LRA indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with a site-controlled corrective action program pursuant to 10 CFR Part 50 (Appendix B), and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is discussed separately in Section 3.1.5 of this SER. The staff finds that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

3.8.3.2.1 Crevice Corrosion, General Corrosion, and Pitting Applicable to Components in SPCS

The applicant has indicated that it is not possible to completely prevent corrosion damage. However, its effects can be mitigated by proper control of the environments to which the components are exposed. These environments consist of saturated steam at high temperature and pressure in the main steam system, two-phase mixture of steam and water in the SG blowdown piping, service or component cooling water in the tube-side of the SG blowdown heat exchanger, and moisture in the nitrogen system. Proper control of secondary water chemistry, using the CCNPP procedure CP-217, "Specifications and Surveillance for Secondary Chemistry," will maintain acceptable purity levels and will control other secondary chemistry parameters. The applicant indicated that as long as SG chemistry is carefully monitored and controlled, the chemistries of the other secondary systems are also successfully controlled.

Corrosive action of service and component cooling water will be mitigated by controlling its water chemistry using the CCNPP procedure CP-206, "Specifications and Surveillance

Component Cooling/Service Water System," and corrosive action of demineralized water, affecting hand valves in the chemical addition system, will be mitigated by ensuring that its chemistry complies with specifications in the CCNPP procedure CP-202, "Specification and Surveillance—Demineralized Water, Safety Related Battery Water, Well Water Systems and Acceptance Criteria for On-Line Monitors."

Nitrogen gas or air in the nitrogen system is corrosive only when the humidity is high. The applicant minimizes humidity in the nitrogen system by using dry nitrogen or dry air from the instrument air system. The applicant minimizes humidity in the instrument air system by maintaining the dew point of the compressed air at – 40 °F at 100 psig.

In addition to controlling water chemistry, the applicant is using the following programs to manage these ARDMs:

- The applicant is managing the effects of corrosion on components in Groups 3 and 6 in the AFW system, listed in Section 3.8.2.2 of this SER, with the CCNPP system walkdown program MN-1-319, "Structure and System Walkdowns." The staff's evaluation of the walkdown program is in Section 3.1.3 of this SER.

- The applicant is managing the effects of corrosion on components in Group 5 (internal surfaces of pump turbines and governor valves) of the AFW system, listed in Section 3.8.2.2 of this SER, with the CCNPP PM program, Repetitive Tasks 10362000, 10362001, 20362018, 20362019, using procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul," and procedure VALVE-28, "Auxiliary Feedwater Pump Turbine Governor Valve Overhaul."

- The applicant is managing the effects of corrosion within the MSIVs and within the applicable portions of the instrument air system that interface with the main steam system with the MSIV-4 Repetitive Tasks 10832098, 10832099, 20832089, 20832090, IPM 10000, and IPM 10001.

The staff finds the scope of the PM program acceptable because it covers the affected components—the AFW pump turbines and governor valves. The staff finds the mitigative action of chemistry control acceptable because it will minimize the corrosiveness of the environment, and thus the rate of corrosion. It also finds the preventive actions taken through the PM program—periodic disassembly and inspections for damage—acceptable because they will prevent or identify degraded conditions. Parameters monitored—measurements to ensure that critical tolerances are within acceptance criteria, wear, erosion, pitting, and/or surface cracking—are acceptable because such parameters will indicate degraded conditions. The monitoring and trending activities are acceptable because they are conducted at established frequencies. The frequencies have been shown to be appropriate by the results of past inspections that showed no defects, such as cracks or corrosion. The monitoring and trending activities are acceptable in that periodic maintenance and inspections will provide adequate information to detect a change in performance that may be associated with aging effects. The staff finds the applicant's acceptance criteria acceptable in that unsatisfactory results are recorded and evaluated. The applicant presented operating experience showing that its activities have been effective in preventing loss of intended function.

To manage the effects of corrosion on the external surfaces of buried pipe of the AFW, (Group 4), the applicant is instituting a new program, the AFW Buried Pipe Inspection Program. This program is identical to the one used for the EDG systems. For the staff's evaluation of this program, see Section 3.7 of this SER.

3.8.3.2.2 Erosion and Cavitation Erosion of Piping and Erosion/Corrosion of Check, Control, and Hand Valves, and Flow Orifices, Heat Exchangers, and MOVs

The components constructed from carbon or low-alloy steel are affected by erosion/corrosion when exposed to turbulent flow of single- or two-phase water at high temperature and/or low pH. In the SPCS, the following types of carbon steel components are susceptible to erosion/corrosion: main steam, main steam drain and SG blowdown piping, different components in the SG heat exchanger tubesheets, and various valves—including main steam to AFW pump check valves and main steam atmospheric dump valves. The SG blowdown piping is also affected by cavitation erosion.

The applicant's mitigation program for the ARDMs caused by erosion/corrosion consists of controlling secondary chemistry using the CCNPP procedure CP-217. The procedure controls purity of water and specifies values of pH at which the effect of erosion/corrosion is minimized. In addition, the applicant has currently an extensive program for inspecting erosion/corrosion–susceptible components. The program is described in the CCNPP Administrative Procedure MN-3-202, "Erosion/Corrosion Monitoring of Secondary Piping." It is based on the predictive methodology developed by EPRI, which includes the CHECKWORKS computer program. All the piping within the scope of the program is evaluated and categorized to determine inspection points. Inspection points are determined based on previous inspections and erosion trends. Inspection results are then analyzed to determine the need to repair or replace components. The ARDI program will include components that are not part of other inspection programs. The program will also include the components affected by cavitation erosion. To specifically manage erosion/corrosion of the FW check valves, the applicant has a program described in the CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program."

The applicant concluded that the programs for minimizing the effect of corrosion and detecting any corrosion damage by inspections will ensure that the ARDMs affecting the components susceptible to erosion/corrosion or cavitation erosion will be properly managed, and all the components in the SPCS will perform their design function during the extended period of operation. After reviewing the applicant's programs, the staff agrees with the applicant's conclusions because similar programs, developed of several other plants, were successful in controlling erosion/corrosion. Also, an audit performed by the staff at five plants has indicated that the programs based on the EPRI-developed methodology can provide a good prediction of the onset of erosion/corrosion damage so that timely corrective actions can be undertaken.

3.8.3.2.3 Selective Leaching of SG Blowdown Radiation Monitor Cooler

This ARDM affects the components in the SG blowdown radiation monitor cooler that are constructed from yellow, red, and forged brass or gray cast iron and exposed to SG blowdown fluid and component cooling water. Since these components form a system pressure-retaining boundary for the safety-related component cooling system, their integrity has to be maintained under all CLB design conditions.

Selective leaching can be mitigated by chemistry controls, and the applicant's aging management program consists of controlling water chemistries in the SG blowdown fluid and in the component cooling water using the CP-217 and CP-206 procedures for secondary and component cooling water, respectively. In addition, the applicant verifies the effectiveness of its chemistry controls through inspections as defined in its ARDI program. The staff finds that these programs will provide sufficient assurance that the components in the SG blowdown radiation monitor cooler will satisfactorily perform their intended functions during the period of extended operation.

3.8.3.2.4 Elastomer Degradation

To manage the effects of elastomer degradation of the perimeter seal in the AFW (Group 9), the applicant is using CCNPP Administrative Procedure MN-1-319, "Structure and System Walkdowns." This program is identical to the one used for the EDG systems. For the staff's evaluation of this program, see Section 3.7.3.2.2 of this SER.

3.8.3.2.5 General Program Applicable to Multiple ARDMs

The applicant is establishing a new program (ARDI) for the following effects and components of the AFW:

- Cavitation erosion of the internal surfaces of AFW piping, downstream of flow orifices (Group 1);
- Crevice corrosion, general corrosion, and pitting of the internal surfaces of AFW system components exposed to the AFW fluid (Group 2); and
- Crevice corrosion, general corrosion, and pitting of 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).

And for the following ARDMs and components of the FW system:

- Corrosion of Group 1 components and erosion/corrosion of MOVs and temperature element thermowells (part of Group 3).

And for the following ARDMs and components of the main steam, SG blowdown, extraction steam, nitrogen and hydrogen systems:

- Corrosion of applicable components (Groups 1, 2, 3, and 4).

For the staff's evaluation of this program, see Section 3.1.6 of this SER.

3.8.3.2.6 Fatigue

The applicant identified a concern with cyclical thermal stratification in the horizontal section of piping adjacent to the SG nozzles. The applicant indicated that thermal stratification could potentially result in more than 7000 full-range stress cycles during the extended period of operation. The applicant concluded that, if left unmanaged, this section of piping could develop fatigue cracking that could affect the ability of the piping to maintain the integrity of the system pressure boundary. Since the applicant considers thermal stratification a significant contributor to low-cycle fatigue for the SG nozzle and adjacent piping, the applicant initiated an evaluation of the affected piping. According to the applicant, the piping adjacent to one SG was instrumented with thermocouples to obtain temperature data around the circumference of the pipe. The applicant sent a sketch of the thermocouple locations in response to NRC Question No. 5.9.40. The staff, in NRC Question No. 5.9.41, asked why the thermal stratification only affected the horizontal section of piping adjacent to the SG FW nozzles. The applicant's response indicates that buoyancy forces prevent hot water from penetrating back through the vertical section of piping which is full of cold water. According to the applicant, thermal stratification causes both local and global effects. Locally, the stratified fluid causes the pipe to ovalize, producing local stresses around the circumference. Globally, bending moments are induced in the pipe because of the restraint of the piping system. The applicant's evaluation of these loads indicated that the highest stress range and fatigue usage occur in the horizontal section of piping adjacent to the FW nozzles. The staff concludes the applicant's explanation is reasonable and, therefore, acceptable.

The applicant indicated that a finite element analysis of the affected piping was performed to determine the most critical location for fatigue. The applicant discussed the analysis model in response to NRC Question No. 5.9.42. According to the applicant, a two-dimensional finite element analysis (FEA) model of the FW nozzle was constructed. This model was used to determine the location at which the stress range due to thermal stratification is maximum. A detailed three-dimensional FEA was then used to evaluate the stresses at the location of maximum stress range. The analysis indicated that the critical location is the safe-end-to-reducer weld. The applicant added this location to the CCNPP FMP. The applicant indicated that the FMP monitors stresses to track the fatigue usage at the weld location. The plant parameter data, which are analyzed periodically, are used to update the fatigue usage. Section 3.1.1 of this SER contains an additional discussion of the FMP. The staff concludes that the applicant has adequately evaluated the safe-end-to-reducer weld.

The applicant also indicated that the normal inservice inspection interval was modified to include an inspection of the critical welds. In the LRA, the applicant indicated that during the last inspection of the Unit 1 welds no flaws were found above the critical flaw sizes as specified in the ASME Code. In addition, the applicant indicated that the Unit 2 welds were inspected during the 1997 refueling outage. In NRC Question No. 5.9.43 the staff asked that the applicant to provide the inspection results. In its response the applicant stated that all indications identified during the inspections of both units were attributed to inside surface geometry. The staff concludes that the applicant's inspections provide additional assurance that fatigue cracks have not initiated at the weld locations.

3.8.3.3 Time-limited Aging Analysis

As discussed previously, the applicant extrapolated the number of full-range thermal cycles expected from operational thermal transients and found that, except for the horizontal section of piping adjacent to the SG FW nozzles, the number of plant transients producing thermal cycles is less than the 7000 allowed by USAS B31.1. On that basis, the applicant concluded that, except for the horizontal section of piping leading to the SG FW nozzle, low-cycle fatigue is not a concern for the FWS piping. The staff considers the applicant's assessment, as discussed above, an acceptable TLAA evaluation for the applicable FW piping. The staff concludes that the applicant's evaluation of the applicable FW piping conforms to the requirements of 10 CFR 54.21(c)(1)(i).

A detailed evaluation of the piping adjacent to the FW nozzles was performed to assess the stresses caused by thermal stratification. EPRI report TR-107515 presents the results of the fatigue analyses of the FW nozzles. Table 3-16 of the EPRI report indicates that fatigue usage factors, without considering environmental effects, will exceed 1.0 in less than 40 years of operation for two Unit 2 steam generator nozzles . Section 3.1.4 of the EPRI report contains a flaw tolerance evaluation in accordance with criteria in ASME Section XI, non-mandatory Appendix L. The flaw tolerance evaluation, using the environmental crack growth data in a proposed ASME Code case, indicates that a postulated fatigue flaw in three of the SG FW nozzles could grow through the wall in less than one operating cycle. The LRA indicated that corrective actions will be initiated well in advance of reaching a fatigue usage factor of 1.0. In NRC Question No. 5.9.44, the staff asked the applicant to describe the corrective actions that will be initiated when the fatigue usage factor approaches 1.0 at the SG FW nozzles. The applicant responded that the EPRI study results do not represent CCNPP fatigue analysis of record (AOR) or the fatigue design basis for any component. Instead the applicant indicated that the study was intended to be representative of conditions for typical older vintage Combustion Engineering pressurized-water reactors, for the purpose of comparing the study results to the results reported in NUREG/CR-6260 for such plants. The applicant stated that the study was not intended to be a CCNPP licensing-basis calculation. The applicant also asserted that the proposed ASME Code case to address environmentally-assisted crack growth is much too conservative to be useful in its current form.

The applicant further indicated that, as discussed in the LRA, the FMP tracks fatigue usage for the critical weld that joins the safe-end to the reducer and that it will take appropriate corrective action before the CUF reaches unity. The applicant will determine such action and may use one or both of the following: (1) implement ultrasonic testing inspections and crack growth analyses under ASME Section XI, non-mandatory Appendix L requirements or (2) replace the reducer, safe-end, and horizontal piping. The staff notes that ASME Code editions containing non-mandatory Appendix L have not yet been endorsed in 10 CFR 50.55a. Therefore, until these ASME Code editions have been endorsed in 10 CFR 50.55a, the use of non-mandatory Appendix L requires staff review and approval.

The EPRI analysis of the piping adjacent to the FW nozzle indicates a potential problem with through-wall cracking that could occur before the end of 40 years of operation. Although the applicant suggests that the EPRI analysis does not represent the CCNPP FW piping, the applicant indicated that the calculated fatigue usage factors presented in the EPRI report are representative of the actual CCNPP values. In a February 18, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant indicated that corrective actions will be implemented before exceeding a fatigue usage factor of 1.0. The applicant's planned corrective action is to replace the affected components. However, the applicant also indicated that if, in the future, the NRC staff accepts the use of ASME Section XI, non-mandatory Appendix L, it may consider applying the Appendix L criteria. The staff concludes that the applicant's actions, as described above, are in accordance with the requirements of 10 CFR 54.21(c)(1)(iii).

As discussed in Chapter 4.0 of this SER, except for portions of the main steam piping, the applicant did not identify that analysis of USAS B31.7, Class II and III piping as a TLAA. However, the staff considers that the applicant's fatigue evaluations of the AFW, FW, and main steam systems as discussed in Section 3.8.3.1.2 of this SER constitute TLAAs. The staff finds that the applicant's assessment described in Section 3.8.3.1.2 of this SER adequate evaluates these TLAAs, and consequently satisfy the requirements of 10 CFR 54.21(c)(1).

3.8.4 Conclusions

The staff has reviewed the information in Section 5.1, "Auxiliary Feedwater System"; Section 5.9, "Feedwater System"; and Section 5.12, "Main Steam, Steam Generator Blowdown, Extraction Steam, Nitrogen and Hydrogen System," of Appendix A to the LRA and additional information sent by the applicant in response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the subject systems will be adequately managed so there is reasonable assurance that the subject systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.9 Sampling and Monitoring Systems

3.9.1 Introduction

The applicant described the AMR of the NSSS sampling system, RMS, and the instrument lines for license renewal in Sections 5.13, 5.14, and 6.4, respectively, of Appendix A to its LRA. The staff has reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the sampling and monitoring systems will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.9.2 Summary of Technical Information in the Application

3.9.2.1 Structures and Components Subject to an Aging Management Review

Section 5.13 of Appendix A to the LRA contains a description of the NSSS sampling system. The system provides for the sampling of liquids, steam, and gases for radioactive and chemical control of plant primary fluids. The NSSS sampling system is comprised of the following five subsystems: (1) reactor coolant sampling, (2) steam generator blowdown sampling, (3) radioactive miscellaneous waste sampling, (4) gas analyzing sampling, and (5) post-accident sampling. The following general categories of equipment and devices comprise the five subsystems of the NSSS sampling system: accumulators, air dryers, piping, valves and valve operators, panels, instruments, sample vessels, heat exchangers (HXs), and pumps. The material for the components is either stainless steel or carbon steel that is compatible with the medium inside the pressure boundary, which is either borated water or chemically treated water. Pursuant to 10 CFR 54.4(a), the NSSS sampling system is in the scope for license renewal based on its intended functions:

- to maintain the pressure boundary of the system (liquid and/or gas)
- to provide containment isolation of the NSSS sampling system during a loss-of-coolant accident
- to provide capability to sample RCS fluid during and after an accident

Some components in the NSSS sampling system are common to many other plant systems and are discussed in separate sections of the LRA that address those components as commodities for the entire plant. These components include structural supports for piping, cables, small-bore piping and tubing, and the associated supports. The applicant has listed NSSS sampling system device types that perform intended functions without moving parts or without a change in configuration or properties (passive intended functions) and that are subject to an AMR in Table 5.13-1 of Appendix A to the LRA.

Section 5.14 of Appendix A to the LRA contains a description of the RMS. The RMS detects an increasing radiation level or an abnormal radioactivity concentration at selected points in the plant and provides indication of such conditions to operating personnel. The system also monitors the discharge of radioactive effluents from the plant and provides a signal to isolate components in the event of an abnormal condition to prevent an uncontrolled release of radioactive material to the environment. The RMS comprises the following types of equipment: piping/tubing, pumps, valves, filters, and instrumentation. The material for the components is either stainless steel or carbon steel that is compatible with the internal environment, which is either ambient air or chemically treated water.

Pursuant to 10 CFR 54.4(a), the RMS is in the scope for license renewal because of the following intended functions:

- Provide containment area radiation signal to the engineered safety features actuation system for containment isolation and radiological release control;
- Provide containment high-range radiation signal for containment environment monitoring and to isolate the containment vent/hydrogen purge lines;
- Maintain the pressure boundary of the system;
- Provide containment isolation of the containment atmosphere and purge air monitor sampling line;
- Monitor and record wide-range gaseous activity/release rate through the main plant vent and provide indications/alarms in the control room;
- Monitor and record radiation levels indicative of effluent activity in the main steam lines and provide indications/alarms in the control room;
- Provide testing capability and prevent spurious actuation of control room radiation monitoring circuitry;
- Maintain electrical continuity and/or provide protection of the electrical equipment;
- Provide seismic integrity and/or protection of safety-related components;
- Provide information to assess the environs and plant condition during and following an accident; and

- Maintain functionality of electrical equipment as addressed by the environmental qualification program

The licensee has identified components of the RMS that have passive intended functions that were subject to AMR in Table 5.14-1 of Appendix A to the LRA.

Section 6.4 of Appendix A to the LRA addresses instrument lines for evaluation. Instrument lines have been evaluated as a "commodity" because they are associated with most plant systems. For the purpose of this evaluation, an "instrument line" is generally defined as those components located downstream of the first hand valve off the main process line or vessel, called the root valve. An instrument line may contain components such as small-bore piping (i.e., 2-inch diameter and smaller), tubing, and fittings from the root valve to the instrument, hand valves, and supports for the tubing. The materials of these components are stainless steel, carbon steel, or copper, depending on the environment inside the component, which is either salt water, borated water, chemically treated water, oil, or air. The applicant has identified systems that contain instrument lines for commodity evaluation in Table 6.4-1 of Appendix A to the LRA. All of the instrument lines that have a intended function of maintaining the system pressure boundary were subject to an AMR with the exception of some instruments such as pressure transmitters, pressure indicators, and water level indicators that perform their intended functions with moving parts or with a change of configuration, and are explicitly excluded from an AMR pursuant to 10 CFR 54.21(a)(1)(i). If an active component also has a passive intended function, as defined by the rule, such as the pressure retaining function of a valve body, that component is subject to an AMR with respect to the passive function.

3.9.2.2 Effects of Aging

The applicant has evaluated the applicability of age related degradation mechanisms (ARDMs) for the components subject to an AMR and determined that the aging effects due to the following "plausible" ARDMs should be managed for license renewal of specific groups of "device types" in the sampling and monitoring systems: crevice corrosion, general corrosion, pitting, fouling, fretting, fatigue, elastomer degradation, and wear. The applicant has grouped each ARDM with device types that have similar characteristics and summarized their evaluation in Appendix A to the LRA: Table 5.13-2 for the NSSS sampling system, Table 5.14-2 for the RMS, and Section 6.4.2 for instrument lines. The applicant has identified the materials of applicable subcomponents in the device types with plausible ARDMs affecting the subcomponent and the effect of each ARDM on the material of the subcomponent. The applicant's management of aging, detailed in Sections 5.13, 5.14, and 6.4 of Appendix A to the LRA, has focused on the mitigation of ARDMs and discovery of the effects of degradation in order to initiate corrective action before the degradation causes the component to fail to perform its intended function. The LRA also contains information on the operating experience relating to failures in sampling and monitoring systems where applicable.

3.9.2.3 Aging Management Programs

The applicant has identified the following AMPs, and the aging effects those programs are intended to manage applicable to the sampling and monitoring systems for license renewal in the LRA:

<u>NSSS Sampling System</u>

- CCNPP Administrative Procedure MN-3-301, "Boric Acid Corrosion Inspection Program," is intended for mitigation and discovery of general corrosion on external surfaces of sample coolers, control valves, and hand valves (included in Group 1) that are exposed to borated water (due to leakage) by performing visual inspections.

- CCNPP Technical Procedure CP-204, "Specification and Surveillance Primary Systems," is intended for mitigation of crevice corrosion and pitting on internal surfaces of sample coolers, hand valves, and solenoid valves (included in Group 2) that are exposed to borated water (as process fluid) by controlling chemistry conditions.

- CCNPP Technical Procedure CP-206, "Specification and Surveillance Component Cooling/Service Water System," is intended for mitigation of crevice corrosion and pitting on internal surfaces of heat exchangers (included in Group 2) that are exposed to chemically treated water from the CC system by controlling chemistry conditions in the CC system.

- CCNPP Technical Procedure CP-217, "Specification and Surveillance: Secondary Chemistry," is intended for mitigation of crevice corrosion and pitting on internal surfaces of sample coolers and hand valves (included in Group 2) that are exposed to steam and feedwater in the steam generator blowdown sampling subsystem (as process fluid) by controlling chemistry conditions.

- CCNPP Surveillance Test M-5711-1(2), "Local Leak Rate Test, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C," is intended for discovery and management of leakage that could result from crevice corrosion and pitting on seating surfaces of the containment isolation solenoid valves in the sample return lines from the reactor coolant sample hoods to the reactor coolant drain tank (included in Group 2).

- CCNPP PM Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality," is intended for mitigation of general corrosion on control valve operators (included in Group 3) by controlling instrument air quality.

- CCNPP Surveillance Test M-571A-1(2), "Local Leak Rate Test, Penetrations 1A, 1B, 1C," is intended for discovery and management of leakage resulting from wear on seating surfaces of the control valves in the RCS hot-leg sampling lines (included in Group 6).

- The CCNPP FMP is intended for discovery and management of thermal fatigue of piping and valves in the RCS hot-leg sampling line (Group 4) by evaluating low-cycle fatigue usage.

- The ARDI program is intended for discovery and management of general corrosion on external surfaces of the miscellaneous waste evaporator concentrate pump discharge sample cooler (included in Group 1), crevice corrosion and pitting on internal surfaces of heat exchangers, hand valves and solenoid valves (included in Group 2), and elastomer degradation in the internals of check valves of the gas return line to the containment from the post-accident sampling system (included in Group 5).

Radiation Monitoring System

- The CCNPP Surveillance Test Procedure identified as STP-M-571E-1(2), “Local Leak Rate Test, Penetrations 15,16, 18, 38, 59, 60, 61, 62, 64," is credited for management of the effects of wear on seating surfaces of the control valves that isolate the containment penetration piping from the containment atmosphere radiation monitors (included in Group 2).

- The ARDI program is intended for management of the effects of crevice corrosion, general corrosion, and pitting of the containment penetration piping associated with the containment atmosphere radiation monitors, the test connection of isolation hand valves that connects to the piping outside the containment, and the control valves that isolate this piping (included in Group 1).

Instrument Lines

- “Structures and System Walkdowns” (MN-1-319), “Control of Shift Activities” (NO-1-200), and “Ownership of Plant Operating Spaces” (NO-1-107), are intended for discovery of the effects of general corrosion of instrument line supports (included in Group 2).

- The ARDI program is intended to provide guidance for expanding of the scope of inspection of the instrument lines originating from main process lines if conditions adverse to quality are found (included in Group 1) and for discovery of the effects of general corrosion and elastomer hardening of the instrument line supports.

The licensee has concluded that these programs would manage the ARDMs and their effects in such a way that the intended functions of the components of the sampling and monitoring systems would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions

3.9.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-Limited Aging Analyses," of Appendix A to the LRA indicates that there is no TLAA applicable to the sampling and monitoring systems.

3.9.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 5.13, 5.14, and 6.4 of Appendix A to the LRA to determine whether the licensee had demonstrated that the effects of aging on the sampling and monitoring system will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation of the license's identification of structures and components subject to an AMR is presented separately in Section 2.2 of this SER. The evaluation of Section 3.9, "Aging Management Review, for the sampling and monitoring systems is presented below.

3.9.3.1 Effects of Aging

The components in the sampling and monitoring systems are constructed of materials such as stainless steel, carbon steel, or copper with an internal environment of either borated water, chemically treated water, air, or oil. Each material is known to be compatible with the medium that it encounters. For example, piping or tubing exposed internally to reactor coolant is made of stainless steel, and the water chemistry is controlled to minimize dissolved oxygen; piping exposed to air is generally carbon steel, and the air is dehumidified; and copper is used in some oil applications. The licensee has identified the following ARDMs as being applicable: general corrosion of external surfaces, crevice corrosion and pitting of internal surfaces, general corrosion of internal surfaces exposed to air, fatigue of piping and valves, elastomer degradation of valve internals and certain supports for instrument lines, and wear for valves. In order to manage the effects of aging for components and structures, the licensee has taken the approach of first identifying the plausible ARDM that is responsible for producing a detrimental aging effect in the component or the structure in the sampling and monitoring systems. The applicant then provided methods to manage each ARDM by identifying techniques for its detection and mitigation.

The applicant has stated that the effects of corrosion—such as general corrosion, crevice corrosion, or pitting—in the NSSS sampling system should be managed for license renewal. Corrosion manifests itself as general corrosion of external surfaces from leakage of borated water on carbon steel and low-alloy steel, or general corrosion of internal surfaces of carbon steel control valve operators exposed to air from the compressed air system or crevice corrosion and pitting of internal surfaces exposed to chemically treated water. The other plausible aging mechanisms identified by the licensee, are fatigue of piping and valves in the sampling lines of the reactor coolant system, elastomer degradation of valve internals, and wear of the control valves associated with sampling of fluid from the reactor coolant system's hot leg. In regard to the RMS, corrosion and wear are identified as the only plausible ARDMs. However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve internals (such as wear and elastomer degradation) because the valve internals perform their intended function with moving parts and changes in configuration and are, therefore, not subject to an AMR for license renewal. The applicant has stated in Section 6.4.2 of Appendix A of the LRA that the instrument line pressure boundary components are subject to the same plausible ARDMs as the main process line pressure boundary components in their respective systems. The external environment is either air or any inadvertent leakage from mechanical joints. Therefore, the licensee has proposed effects of aging for which management is required so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The staff agrees with the applicant's identification of aging effects.

3.9.3.2 Aging Management Programs

The staff has evaluated each applicable aging management program to determine if it contains the following 10 elements constituting an adequate aging management program for license renewal: scope of program, preventive actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The LRA indicated that activities for license renewal will be conducted in accordance with programs meeting the requirements of 10 CFR Part 50 (Appendix B), and will cover all structures and components subject to an AMR. 10 CFR Part 50 (Appendix B), requires, in part, determination of root cause and corrective actions to prevent recurrence, and control of special processes, including qualified personnel and procedures. Although 10 CFR Part 50 (Appendix B), applies to safety-related structures and components, the applicant is committing to extend its Appendix B program to cover all structures and components subject to an AMR whether they are safety-related or not.

3.9.3.2.1 Effects of Corrosion

The applicant has stated that the effects of corrosion (crevice corrosion, general corrosion, and pitting) should be managed for license renewal. Hence, the applicant has evaluated corrosion on external and internal surfaces of components.

3.9.3.2.1.1 Corrosion of External Surfaces

The components such as heat exchangers, control valves, and hand valves in the NSSS sampling system are exposed to climate-controlled air in the auxiliary building or in the containment. The subcomponents in these devices are constructed of carbon steel and alloy steel and their external surfaces are subject to general corrosion. The external surfaces are not normally exposed to a corrosive environment, but may be exposed to boric acid as a result of leakage from the associated components. The RMS and the instrument lines, including the supports that are made of carbon steel, are susceptible to corrosion of external surfaces. The external surfaces of the carbon steel subcomponents are covered by a protective coating that mitigates the effects of general corrosion. The AMPs credited with discovering the effects of general corrosion of the external surfaces are the ARDI program and the structure and system walkdown program (MN-1-319). Boric acid corrosion is mitigated by minimizing leakage. The susceptible areas of the NSSS sampling system (i.e., bolted joints) can be routinely observed for signs of borated water leakage, and appropriate corrective action can be initiated as necessary to eliminate leakage, clean spill areas, and assess any corrosion. The effects of external corrosion are generally visually detectable. The aging management program that is credited with discovering the effects of boric acid corrosion, is the CCNPP BACI program (MN-3-301). As discussed in the staff's evaluation of this program in Section 3.1.4 of this SER, the discovery of boric acid leakage is ensured by the BACI program. In accordance with this program, during each refueling outage, inservice inspection personnel perform a walkdown inspection to identify and quantify any leakage found at specific locations inside the containment and in the auxiliary building. The inservice inspection provides that all components at which boric acid leakage has been previously documented are also examined in accordance with this program. These components are inspected again before plant startup (at normal operating pressure and temperature) if leakage was identified previously and corrective actions were taken. The staff finds that the programs proposed by the licensee, for the NSSS sampling system components subject to an AMR, provide adequate assurance by periodic inspection, that corrosion has not occurred on external surfaces and that intended functions are maintained.

3.9.3.2.1.2 Crevice Corrosion and Pitting of Internal Surfaces

Various NSSS sampling system components are exposed to chemically treated water, and their internal surfaces are subject to crevice corrosion and pitting. The subcomponents in this group are included in the heat exchanger, hand valve, and solenoid valve device types. The materials for the internals of these subcomponents are carbon steel, stainless steel, and copper. The internal surfaces are exposed to an environment of chemically treated water from the system being sampled or from the component cooling system. Crevice corrosion can occur in crevices that trap chemically treated water and pitting can occur under stagnating flow conditions. Both forms of corrosion are plausible ARDMs for the subcomponents of device types such as heat exchangers, hand valves, and solenoid valves. The subcomponents of these device types in the RMS that are constructed from carbon steel and alloy steel are also susceptible to crevice corrosion and pitting in a warm and humid air environment. These aging mechanisms, if unmanaged, could eventually lead to the loss of integrity of the system pressure boundary for the piping, and hence, the loss of intended function of the component. Although the effects of crevice corrosion and pitting cannot be completely prevented, they can be mitigated by minimizing the exposure of carbon steel to an aggressive environment or by controlling the fluid chemistry in systems that interface with the sampling and monitoring systems. The staff finds that the chemistry program at CCNPP is established to minimize impurity ingress to plant systems, reduce corrosion product generation, transport, and deposition, and therefore, extend component life (see Section 3.1.2 of this SER). The effect of corrosion is generally detectable by visual examination. The staff has concluded that examinations to be performed under the applicant's ARDI program will provide reasonable assurance that aging effects from the ARDMs described above will be detected in a timely manner. The staff's evaluation of ARDIs is discussed in Section 3.1.6 of this SER.

3.9.3.2.2 Effects of Wear

The control valves in the reactor coolant sampling subsystem and the RMS are subject to wear on the seating surfaces. The materials of the valve internals are compatible with the internal environment of the reactor coolant sampling system and the RMS. However, wear on the seating surface results from relative motion between two surfaces that are in contact with each other. The applicant has identified wear as a plausible ARDM for control valves since the aging mechanism, if unmanaged, could eventually result in a loss of the pressure-retaining function under current licensing basis conditions . However, as discussed in Section 3.3.3.1 of this SER, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and are, therefore, not subject to an AMR for license renewal.

3.9.3.2.3 Effects of Fatigue

The licensee has stated that fatigue is a plausible ARDM for components such as valves and certain pipe segments in the reactor coolant sampling subsystem associated with sampling of the fluid from the RCS hot leg. These components provide the passive intended function of maintaining the system pressure boundary. The material for the pressure boundary is stainless steel with an internal environment of borated water. The bolting material is low-alloy steel or carbon steel. Low-cycle thermal fatigue is a plausible ARDM for components in the reactor coolant sampling subsystem since they experience severe thermal cycling during routine RCS sampling operations. This aging mechanism, if unmanaged, could eventually result in crack initiation and growth so that the components may not be able to perform their pressure boundary function under CLB design loading conditions. However, the licensee has not discovered any low-cycle fatigue-related failures in the NSSS sampling system. The licensee has stated that there are no practicable means available to mitigate the effects of thermal fatigue, but has established an FMP to monitor and track fatigue usage factors of limiting components of the NSSS and steam generators. Tracking the usage factors of the limiting components ensures that all remaining components will also remain below their fatigue limits. The FMP will include an engineering evaluation to determine if the low-cycle fatigue usage of piping and valves in the RCS hot-leg sampling line is bounded by the existing analysis for the bounding components. If these components are not bounded, they will be reviewed in accordance with the FMP to verify the fatigue usage factor for these components, and consideration will be given to the magnitude and frequency of thermal cycles imposed by RCS sampling activities. The staff considers this approach for monitoring fatigue usage factors of components in the NSSS sampling system acceptable for managing this ARDM so that these components will be capable of performing their intended functions consistent with the CLB during the period of extended operation under all design loading conditions. In the previous SER, the staff requested the applicant to provide its evaluation as stated in page 5.13-29 of Appendix A to the LRA, to demonstrate that the low-cycle fatigue usage of piping and valves in the RCS hot-leg sampling is bounded by the monitoring of 11 fatigue-critical locations in the RCS. This was identified as Open Item 3.9.3.2.3-1. By letter dated July 2, 1999, the applicant committed to completing this evaluation, including any changes to the FMP resulting from the evaluation, by the end of 2003. The staff finds this commitment satisfactory and considers Open Item 3.9.3.2.3-1 closed.

3.9.3.2.4 Effects of Elastomer Degradation

The internals of check valves in the post-accident sampling system (PASS) gas return line to the containment and some of the supports in the instrument line contain elastomer materials that are susceptible to age related degradation. The check valves and the supports in the instrument line provide the passive intended function of maintaining the system pressure boundary.

The applicant has stated that the effects of elastomer degradation should be managed for the check valves in the gas return line to the containment from the PASS cabinet and the supports in the instrument lines. The staff has concluded that the applicant's ARDI program for aging management of elastomer degradation of these components provides reasonable assurance that this ARDM will be effectively managed. The staff's evaluation of ARDIs is discussed in Section 3.1.6 of this SER.

It should be noted, as discussed in Section 3.3.3.1 of this SER, that for the check valve internals, the staff did not evaluate the aging management of valve internals because the valve internals perform their intended function with moving parts and changes in configuration and are, therefore, not subject to an AMR for license renewal.

3.9.3.3 Time-Limited Aging Analyses

Low-cycle thermal fatigue for the NSSS sampling system is addressed in Section 3.9.3.2.3 of this SER. The CCNPP FMP monitors and tracks the fatigue usage for critical components of the NSSS. The staff's evaluation of the TLAA is contained in Section 3.2.3.3 of this SER.

3.9.4 Conclusions

The staff has reviewed the information in Section 5.13, "NSSS Sampling System"; Section 5.14, "Radiation Monitoring System"; and Section 6.4, "Instrument Lines," of Appendix A to the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the sampling and monitoring systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.10 Building Structures

3.10.1 Introduction

The applicant described its AMR of the building structures (BSs) for license renewal in five separate sections of its license renewal application (LRA). These five sections are Section 3.3A, "Primary Containment Structures (PCSs)"; Section 3.3B, "Turbine Building Structure (TB)"; Section 3.3C, "IS"; Section 3.3D, "Miscellaneous Tank and Valve Enclosures (MTVEs)"; and Section 3.3E, "Auxiliary Building and Safety-Related Diesel Generator Building Structures (AB&SR-DGB)," of Appendix A to the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the PCSs, TB, IS, MTVEs, and AB&SR-DGB will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.10.2 Summary of Technical Information in the Application

3.10.2.1 Structures and Components Subject to an Aging Management Review

Section 3.3A of Appendix A to the LRA contains a description of the primary containment structure (PCS). The PCS consists of two categories of components, the containment structure and the containment system. The containment structure contains the majority of structural components, such as beams, columns, walls, slabs, and liners. The containment system contains penetrations, hatches, air locks, and associated instrumentation.

The containment structure and its structural components provide structural/functional support and shelter/protection for safety-related 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 the postulated design-basis events (DBEs). In addition, the containment structure serves as a missile, flood, and fire barrier for safety-related equipment. The boundary for the containment structure as defined by the applicant encompasses all components inside the containment structure serving safety-related functions and components defining the containment pressure boundary, but it does not include commodity items such as pipe supports and snubbers.

Section 3.3B of Appendix A to the LRA describes a turbine building (TB). The TB is a steel-framed structure, with metal siding, supported on a reinforced-concrete foundation. The TB is a seismic Category II structure except for the auxiliary feedwater (AFW) pump rooms, which are seismic Category I. The scope of license renewal for the TB includes AFW pump rooms and their associated structural components, the electrical duct banks that run under the TB between the AFW pump rooms and the IS, the siding clips of the TB, the retainer clips on the TB side of the wall that separates the auxiliary building from the TB, and caulking and sealants that provide flood protection barriers and rated fire barriers.

The TB siding is classified as non-safety-related, and the siding clips that hold the siding in place are classified as safety-related. The siding clips are designed to fail when the differential pressure across the siding reaches a predetermined value. This design allows the siding to be blown off when the predetermined pressure is reached, and thereby provide venting after a postulated break of the main steam line in the auxiliary building or the TB. There is a wall at the end of the main steam pipe tunnel, which separates the auxiliary building from the TB, and the wall is designed to fail at 0.5 psi so that the pressure will vent into the TB 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 pipe area.

Section 3.3C of Appendix A to the LRA describes the IS, including scoping, conceptual boundaries, descriptions of components subjected to AMR, and aging management methods. Section 3.3C of Appendix A to the LRA addresses the component-level scoping results for the structural-type components of the IS.

The IS is situated to the east of the main plant between the North Service Building and the Chesapeake Bay shoreline. The structure houses 12 circulating water pumps that supply water from the bay to the condensers, and 6 saltwater pumps that provide cooling water to various plant equipment. The IS is approximately 90-ft wide and 385-ft long, and is primarily constructed of reinforced concrete. The foundation slab varies in elevation from -26 feet to -14 feet 3 inch For all major structural components (walls, slabs, etc.) below finished grade, 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.

Section 3.3D of Appendix A to the LRA describes the No. 12 condensate storage tank (CST) enclosure, the No. 21 fuel oil storage tank (FOST) enclosure, and the AFW valve enclosure. The three categories of structural components subject to an AMR contained in the No. 12 CST, No. 21 FOST, and AFW valve enclosures are concrete components, structural steel components, and unique components. Within the three structural component categories, 17 structural component types were determined to either provide structural or functional support to safety-related equipment, provide shelter to safety-related equipment, serve as a missile barrier, and/or provide structural or functional support to non-safety-related equipment whose failure could have an effect on a required safety-related function. Concrete components are the foundations, walls, roof slabs, anchors, and grout of the three enclosures. Structural steel components are beams, baseplates, roof framing, bracing, platform hangers, decking, floor grating, and stairs and ladders of the three enclosures. Unique components are anchor brackets, manhole framing, and a manhole cover.

Section 3.3E of Appendix A to the LRA describes the auxiliary building and safety-related diesel generator building (AB&SR-DGB) structures. The AB&SR-DGB structures consist of the auxiliary building, the adjacent emergency diesel generator (EDG) rooms, the refueling water tank (RWT) pump rooms, the SR-DGB, and the ductbank for EDG 1A. In addition, by letter dated October 22, 1999, in response to Open Item 2.2.3.8-1, the applicant has included the station blackout (SBO) diesel generator (DG) building no. 2 as part of the AB&SR-DGB structures that are within the scope of license renewal.

The SR-DGB is located northwest of the auxiliary building and houses EDG 1A, which is one of four safety-related EDGs designed to provide a dependable onsite power source. The SR-DGB also houses the fuel oil tank for EDG 1A and other auxiliary equipment. The conceptual boundary of the SR-DGB encompasses all structural components, such as concrete foundation, walls, and slabs, as well as a buried ductbank that runs between the SR-DGB and the auxiliary building for the electrical distribution from EDG 1A.

The PCS, TB, IS, MTVE, and the AB&SR-DGB structures are included within the scope of license renewal because these structures perform one or more of the following seven structural functions:

- Provide structural and/or functional support to safety-related equipment.
- Provide shelter/protection to safety-related equipment.
- Serve as a pressure boundary or a fission-product retention barrier.
- Serve as a missile barrier.
- Provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions (e.g., seismic Category II over I design considerations).
- Provide flood protection barrier.
- Provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.

3.10.2.2 Effects of Aging

The applicant evaluated the applicability of age-related degradation mechanisms (ARDMs) to the PCS, which requires an AMR. The applicant determined that the aging effects of the PCS from the following "plausible" ARDMs should be managed for license renewal: corrosion of steel, corrosion of tendons, prestressing losses, corrosion of containment wall and dome liner, and weathering of grout. The applicant's evaluation of the potential and plausible ARDMs for the PCS is summarized in Table 3.3A-3 of Appendix A to the LRA. The LRA also contains information on the CCNPP operating experience with respect to the aging degradation of the PCS. The applicant indicated that the Unit 1 PCS was inspected in 1992 to support the applicant's license renewal work. The applicant reported that the inspection determined that both the exterior and interior surfaces of the containment structure and components in the containment system were in good to excellent condition. However, in 1997, the applicant discovered a number of prestressing tendons in Unit 1 with severe corrosion 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. The applicant's resolution of this issue is currently under staff review pursuant to 10 CFR Part 50 requirements.

The applicant evaluated the TB components subject to an AMR, and identified two plausible ARDMs: weathering of caulking and sealants and corrosion of steel. The applicant determined that the aging effects from these plausible ARDMs should be managed for license renewal. The applicant's evaluation of the effects of aging and the methods of aging management is documented in Section 3.3B.2 of Appendix A to the LRA. The LRA also contains information on the CCNPP operating experience with respect to aging effects on caulking and sealants and steel corrosion of the TB steel. This operating experience, related to fire barrier penetration seals, has shown that aging is a minor contributor to the seal failure. The applicant stated that the greatest contributor to degradation of these seals is believed to be due to inadequacies in the original installation of the seal materials. For the caulking and sealants that do not perform a fire barrier function, the applicant's experience indicated a need for a new CCNPP Caulking and Sealant Inspection Program to adequately manage their aging effects. Regarding the corrosion of the TB steel, the applicant observed some steel corrosion both at the interior and exterior of the AFW Pump Rooms.

The structural component types in the IS, such as walls, baseplates, and watertight doors, are identified with respect to their functions; for example, watertight doors provide protection to safety-related equipment, and provide flood protection. All of the 27 such structural types that have been identified for the IS are subjected to an AMR. Table 3.3C-3 of Appendix A to the LRA shows the component types against the identified ARDMs. The applicant stated that the effects of aging for the following three items should be managed: (1) caulking, sealants, and expansion joints subject to weathering; (2) fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel/rebar; and (3) steel components and sluice gates subject to corrosion.

The applicant identified the corrosion of steel components as the only significant potential ARDM for the miscellaneous tank and valve enclosure components. Each of the components associated with miscellaneous tank and valve enclosures except for the foundations, walls, roof slabs, and grout, are fabricated from carbon steel, which is subject to general corrosion when exposed to moisture and oxygen. Since the No. 12 CST, No. 21 FOST, and AFW valve enclosures are not weather-tight, the applicant considers the internal environment of the three enclosures to be the same as the external environment. As such, all components are assumed to experience the same temperature ranges and moisture as outdoor components at CCNPP. Since the applicant recognized corrosion as a potential degradation mechanism for carbon steel components, exposed structural steel surfaces in the three enclosures were coated during the construction phase. Coatings serve as a protective layer, preventing moisture and oxygen from directly contacting the steel surfaces.

The applicant evaluated the applicability of the ARDMs noted above to the components of the AB&SR-DGB, which are subjected to an AMR, and identified four applicable aging effects: weathering of caulking, sealants, and expansion joints; corrosion of steel; corrosion of the spent fuel pool (SFP) liner (sensitized zones); and degradation of neutron-absorbing materials (for SFP storage racks). The applicant determined that these aging effects on the AB&SR-DGB from the ARDMs should be managed for license renewal. The applicant's evaluation is summarized in Table 3.3E-3 of Appendix A to the LRA. The LRA also contains information on the CCNPP operating experience, including some water leakages from the CCNPP Unit 2 spent fuel pool and degradation, as well as loss, of Boraflex material in the Unit 2 spent fuel racks.

The applicant's LRA also describes the potential for foundation settlement as an ARDM. However, the applicant does not consider foundation settlement as a plausible ARDM since, other than minor initial settlement cracks, no cracking or evidence of additional settlement that would affect the structural integrity of CCNPP's structural foundations has been observed to date.

3.10.2.3 Aging Management Programs

The applicant identified the following AMPs for the building structures covered under Section 3.3 of Appendix A to the LRA:

- PM Program Procedure PAL-2 (existing program)
- Containment Emergency Sump Inspection Procedures STP-M-661-1 for Unit 1 and STP-M-661-2 for Unit 2 (existing program)
- Painting and Other Protective Coatings Procedures, MN-3-100 (existing program)
- Liner Plate Surveillance Test Procedures STP-M-665-1 for Unit 1 and STP-M-665-2 for Unit 2 (existing program)
- Containment Tendon Surveillance Test Procedures STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2 (modified program)
- Structure and System Walkdowns, Procedure MN-1-319 (modified program)
- CCNPP Surveillance Test Procedure STP-F592-1/2, "Penetration Fire Barrier Inspection" (existing program)

- Caulking and Sealant Inspection Program (new program)
- PM Program for IS Cavity Repairs and Cleaning During Refueling Outages (modified program)
- PM Program for Inspection of Sluice Gates (modified or new program)
- Operations Section Performance Evaluation PE 0-67-2-O-M, "#11 & #12 Spent Fuel Pool—Determine Liner Leakage," and associated Operating Instruction OI-24D, "Spent Fuel Cooling—Infrequent Operations" (existing programs).
- ETP 86-03R, "Analysis of Neutron-Absorbing Material in Spent Fuel Storage Racks" (existing program)

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended function of the components of the CCNPP building structures would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.10.2.4 Time-Limited Aging Analysis

Section 2.1, Table 2.1-1 of Appendix A to the LRA contains a list of TLAAs to be performed or evaluated by the applicant as part of the current LRA. The applicant proposed the following three TLAAs that are pertinent to the LRA for CCNPP building structures: (1) containment liner plate fatigue analysis, (2) containment tendon prestress loss analysis and (3) poison sheets in spent fuel pool analysis.

The applicant discussed, in Section 2.1 of Appendix A of the LRA, key technical factors and assumptions that need to be considered in each of the TLAAs listed above. The applicant also proposed to reanalyze, update, or complete these TLAAs by year 2012, 2012, and 2000 for items 1, 2, and 3, respectively.

3.10.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information presented in Sections 3.3A, 3.3B, 3.3C, 3.3D, and 3.3E of Appendix A to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation for the CCNPP building structures. The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER.

By letter dated April 8, 1998, the applicant submitted its LRA. By letter dated September 7, 1998, the staff issued several RAIs after completing the initial review. By letter dated November 11, 1998, the applicant responded to the staff's RAI.

The staff held CCNPP site meetings with the applicant from February 16, through February 18, 1999 (NRC meeting summary dated March 19, 1999), to discuss open items derived from staff review of the applicant's response to the RAIS, and to obtain additional clarifications related to the applicant's response.

3.10.3.1 Effects of Aging

The scope of building structures whose aging effects are evaluated covers the following structures and components:

The PCS consists of two groups of components, i.e., the containment structure and the Containment System. The containment structure includes the majority of structural components, such as beams, columns, walls, crane girders, removable missile shield, pipe-whip restraints, and liners. These components are constructed of concrete, reinforcement, structural steel, carbon steel liners, and post-tensioning systems. The Containment System includes penetrations, hatches, and air locks, which are constructed of carbon steel, and associated instrumentation.

The TB is a steel-framed structure, with metal siding, supported on a reinforced-concrete foundation. 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.

The IS is approximately 90 feet x 385 feet and is constructed primarily of reinforced concrete. The foundation slab varies in elevation from -26 feet 0 inch to -14 feet 3 inch. 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.

A majority of the structural components in the No. 12 CST, No. 21 FOST, and AFW valve enclosures are fabricated from carbon steel.

The components in the AB&SR-DGB structures are constructed of concrete, reinforcement bars, structural steel, stainless steel liners, expansion joints, and materials including compounds, sealants, and boron carbide in a Fiberglas matrix.

Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds the applicant's approach of identifying ARDMs acceptable because the approach is a comprehensive way to identify applicable aging effects for the building structures. The plausible ARDMs identified by the applicant for the building structures are corrosion of steel, corrosion of tendons, degradation of concrete elements, corrosion of concrete reinforcement, corrosion of liner, corrosion of permanent cavity seal ring, tendon prestress losses, general corrosion and oxidation of penetrations, personal/emergency air locks and equipment hatch, weathering of grout, weathering of caulking and sealants, and degradation of carborundum and boraflex materials. The staff finds that the ARDMs identified by the applicant are sufficient in scope and cover plausible ARDMs for the CCNPP building structures and, therefore, are acceptable.

During the component level scoping process, the applicant identified a list of generic structural component types for the building structures. Additional structural component types, not included in the generic listing because they are unique to a structure, were also identified by the applicant. The potential ARDMs discussed above were considered by the applicant in conjunction with the structural component types to facilitate the discussion of aging effects management. For efficiency in presenting the results of these evaluations, structural component types/AMR combinations are grouped together where there are similar characteristics within the structural component group, and the discussion is applicable to the structural components within that group. The staff agrees with this approach because it is an efficient and practical way for systematically evaluating the plausible aging effects.

The applicant presented an adequate discussion of the CCNPP operating experience in the application and indicated that building structures had, in general, performed adequately, except that corrosion and degradation of the prestressing system and containment liners have been experienced. The staff also finds that the applicant's discussions of other observed building structure degradations, such as concrete containment degradation, basemat cracking, weathering of caulking and sealants, corrosion, experience regarding the buried pipes, and loss of prestressing forces for the horizontal hoop and dome tendons, are sufficient in scope and adequate in description.

The applicant determined that the following effects of aging should be managed:

- corrosion of tendons and prestressing losses
- corrosion of steel
- corrosion of containment wall and dome liners
- corrosion of refueling/spent fuel pool liners and PCSR
- degradation of fluid-retaining walls and slabs subject to aggressive chemical attack on concrete and corrosion of embedded steel reinforcing bars
- weathering of caulking, sealants, and expansion joints

- corrosion of sluice gates
- weathering of grout
- degradation of neutron-absorbing materials

On the basis of the preceding discussions, including the ARDMs identified and the effects of aging resulting from the ARDMs, the staff agrees that effective aging management of the items listed above will ensure that CCNPP building structures and related components will perform their intended safety function for the extended period of operation.

The applicant also discussed the containment basemat settlement related to the bearing capacity of the foundation medium and a conservatively evaluated average basemat bearing pressure as well as the foundation medium type extracted from the CCNPP FSAR. The applicant concluded in its LRA that long-term settlement, including differential settlement at CCNPP, was not plausible for the containment structure based on (1) ample bearing capacity compared to the computed basemat bearing pressure, (2) use of a permanent pipe drain system, and (3) an engineering judgment that a thick basemat tends to settle uniformly as a rigid body. The staff finds that the applicant's justification for drawing this conclusion is both reasonable and acceptable.

3.10.3.2 Aging Management Programs

The staff focused its evaluation of the applicant's AMP on the program elements rather than on the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that the analysis/assessment, corrective action, and confirmation/ documentation process for license renewal is in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50 (Appendix B) and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective actions program is discussed separately in Section 3.1.5 of this SER. The staff finds that the applicant's AMP for license renewal satisfies the elements of "corrective actions," "confirmation process," and "administrative controls."

3.10.3.2.1 Corrosion of Tendons and Prestressing Losses

The applicant identified the corrosion of tendons and prestress losses as two ARDMs affecting the CCNPP containment post-tensioning system and described the material used for and the environment affecting the system. The applicant stated that most corrosion-related failures of prestressing tendons have been attributed to pitting, stress corrosion, hydrogen embrittlement, or some combination of these three causes. The applicant concluded that corrosion of tendons is a plausible aging mechanism for the post-tensioning system and it causes cracking or reduction in the wire's cross-sectional area, which, in turn, may lead to a loss of prestressing force and a reduction in the margin of the containment's capacity to resist design-basis loads. The applicant also stated that prestress losses are the results of (1) stress relaxation of prestressing wires; (2) shrinkage, creep, and elastic deformation of concrete; (3) anchorage seating losses; (4) tendon friction; and (5) reduction in wire cross-section from corrosion that leads to the wire reaching its yield point.

The applicant further concluded that 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.

As evidence of corrosion-related degradation of post-tensioning tendons, the applicant described the abnormal condition of tendons found during the 20-year tendon surveillance in 1997. During testing of selected vertical tendons to determine the lift-off forces, broken wires were discovered. The discovery initiated an expansion of the vertical tendon samples for visual examination and lift-off testing. At the completion of the expanded scope, 32 percent of the vertical tendons were identified as having corrosion and broken wires. The short-term corrective action plan and the long-term corrective action plan are being implemented by the applicant under the current licensing basis to ensure the integrity of the prestressing tendons and to alleviate the potential for such occurrences in the future.

On the basis of the description of the aging effects (i.e., corrosion of prestressing tendon system and losses in prestressing tendon force), the staff concludes that the applicant recognizes the importance of these effects with respect to measures taken in ensuring the integrity of the containment structure.

The applicant stated that the effects of tendon corrosion can be mitigated by minimizing the exposure of the post-tensioning system to moisture and maintaining a good coating of grease on tendon steel wires. It stated that the effects of tendon corrosion can be detected. The applicant indicated that containment tendon surveillance is periodically performed on the CCNPP post-tensioning system in accordance with the CCNPP surveillance test procedures STP-M-663-1 and STP-M-663-2 for Units 1 and 2, respectively. These surveillance programs consist primarily of visual inspection, tendon sampling procedures, tendon lift-off force test, sample wire inspection, and minimum tensile strength test and chemical analysis of the sheath filler grease. The prestress force data and physical condition data obtained during each surveillance test are evaluated in accordance with the guidance in Position 7 of Regulatory Guide 1.35, Rev. 2, so that the integrity of the prestressed tendon system is ensured. The applicant has committed to revising these tendon surveillance programs to reflect the provisions of Regulatory Guide 1.35, Rev. 3 and the provisions of 10 CFR 50.55(a), incorporating the ASME Section XI, Subsection IWE/IWL requirements.

As part of the operating experience, the applicant summarized the following: In 1997, CCNPP Units 1 and 2 have experienced degradation in their containment prestressing systems. The applicant sent NRC its evaluation of this condition in a letter dated October 28, 1997. The applicant also briefly described the condition as well as its planned disposition of the issue. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the staff asked the applicant to explain why hoop and dome tendons are not experiencing the same type of corrosion as the vertical tendons. The applicant stated that the dome tendon grease cans are oriented in such a way that rain-water is unlikely to pool on the grease can and leak into it, and the tendons are also shielded from the weather by siding. Therefore, a failure mechanism requiring substantial water leakage is unlikely to affect the dome tendons. The applicant indicated that the hoop tendons have the potential of being affected by water in-leakage. Several hoop tendons are below ground level and have been submerged for periods of time. In order to determine if these hoop tendons have been affected by in-leakage, they were visually inspected. That inspection revealed no abnormal degradation or corrosion of the tendons. Since these tendons are unaffected by corrosion, it is unlikely that other hoop tendons will be affected. The applicant further stated that these tendons are also oriented so that a void in the grease would not form immediately below the stressing washer because the stressing washer surfaces are not horizontal. With adequate grease coverage, the applicant believes that the potential for corrosion attack of these two types of tendons is minimal. The staff finds this explanation reasonable and acceptable. The applicant's long-term corrective action program was reviewed by the staff and was found acceptable under the current license.

In NRC Question No. 3.3.12, the staff asked the applicant to summarize the TLAA that will be performed for the three types of containment prestressing tendons and to explain the basic assumptions and limitations that will be used in the evaluation. In response to NRC Question No. 3.3.12, the applicant indicated that the expected tendon force curve would be based on straight lines plotted on semi-log paper like most time-dependent decay curves. Upper and lower bounds are usually drawn parallel, and superimposed on the plot with some lower limits to reflect design requirements with some margin. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant stated that according to information provided in a letter from the applicant to the NRC dated October 28, 1997, the vertical tendons, in general, possess reasonable tendon lift-off force margins on the order of 25 kips. The staff asked the applicant to demonstrate that the trending analyses of the three types of tendons will ensure that the actual prestressing forces in the tendons are above the lower bound limits during the period of extended operation. This was identified as Open Item 3.10.3.2.1-1 in the previous SER. The resolution of this open item is discussed in Section 3.10.3.3.1 of this SER.

In NRC Question No. 3.3.17, the staff asked the applicant to discuss how STP-M-663-1/2 surveillance procedures effectively manage the potential additional tendon force loss (8 to 14%)

from elevated temperature resulting from exposure to the sun or proximity to hot penetrations (refer to NUREG-1611, "Aging Management of Nuclear Power Plant Containments for License Renewal," page 18, issue 14). The applicant stated that its STPs have not addressed local elevated temperatures from sun exposure and hot penetrations and indicated that although the applicant has seen indications of more tendon relaxation on the west side, it has not observed a consistent pattern of tendon force degradation. The staff and the applicant discussed this issue at the February 17, 1999, meeting, at the CCNPP site (NRC meeting summary dated March 19, 1999). The applicant stated that the affects on tendon force of elevated temperature from sun exposure or proximity to hot penetrations would be detected by STP M-663 procedure and operability of the containment, as it relates to tendon forces, is governed by the requirements of CCNPP UFSAR technical specification 15.6.1. The applicant also stated that testing is performed according to STP M-663 and a reduction in tendon force will be detected during conduct of the test regardless of the cause. The applicant maintained that if the technical specification requirements are satisfied, then, by definition the containment is operable. The staff finds the applicant's discussion reasonable and adequate to resolve the issue raised by the RAI.

On the basis of the preceding information, the applicant concluded that (1) containment tendons are essential to maintain the containment pressure boundary and its integrity must be maintained under the CLB design loading conditions; (2) containment tendons are susceptible to corrosion and prestress losses; (3) grease coating mitigates the effects of corrosion and containment tendon surveillance is periodically performed, according to the CCNPP STP-M-663-1/2 tendon surveillance program, to ensure the integrity of the prestressing system. The staff assessment of the program indicates that it will (1) ensure the encapsulation of the tendon anchorage components and wires in corrosion-inhibiting grease that would protect them against corrosion, (2) monitor the grease leakage, the amount of contaminants (e.g., chlorides), and water in the grease, (3) detect the degradation of material properties of corrosion-inhibiting grease and tendon wires due to aging, and (4) assess the trend of tendon prestressing forces to ensure that they meet the minimum required prestress levels. Thus, with the resolution of Open Item 3.10.3.2.1-1, the staff concludes that the applicant's program for monitoring the aging degradation of the prestressing tendon system is adequate and acceptable.

3.10.3.2.2 Degradation of Concrete Elements and Corrosion of Concrete Reinforcement

For concrete elements within the scope of CCNPP building structures, in response to NRC Question No. 3.3.2, the applicant discussed the potential aging effects of degradation of concrete and corrosion of concrete reinforcement from freeze-thaw, leaching of calcium hydroxide, aggressive chemical attack, aggregate reaction, flowing water, and corrosion of embedded steel/rebar as potential ARDMs.

The applicant considered freeze-thaw as a potential ARDM for concrete structural components that are exposed to outdoor cold weather because the CCNPP site is located in a geographic region subject to severe weather conditions according to American Society for Testing and

Materials (ASTM)-C33, "Standard Specification for Concrete Aggregates." The applicant stated that freeze-thaw is not a potential ARDM for concrete structural components below the frost line (depth of 20–22 inch) or for components located indoors. The applicant stated that the concrete components potentially subject to freeze-thaw were designed and constructed in accordance with ACI Standard 318, "Building Code Requirements for Reinforced Concrete," and its relevant ACI standards and ASTM specifications, which state the physical property requirements of aggregate and air-entraining admixtures, chemical and physical requirements of air-entraining cements, and proportioning of concrete containing entrained air to maximize the concrete resistance to freeze-thaw action. Furthermore, Table B9 in NUREG-1557, "Summary of Technical Information and Agreements From Nuclear Management and Resources Council Industry Reports Addressing License Renewal," states that freeze-thaw is a non-significant ARDM for structures that meet the basis requirements. The applicant maintained that since the CCNPP structures meet the basis requirements, freeze-thaw is not a plausible ARDM for concrete components exposed to outdoor cold weather. However, the applicant stated that its walkdown inspections found evidence of damage from freeze-thaw of the containment dome with some exposed aggregates, but concluded that the observed degradation, even if the concrete were left unmanaged, would not result in a loss of function. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the staff asked the applicant to explain the basis for the preceding conclusion. The applicant restated that the possible freeze-thaw damage on the containment dome is expected to be insignificant and this item will be evaluated further as part of the baseline inspection for both containments by year 2002. Based on decades of staff experience in concrete containment construction and maintenance work, the staff deems that a few exposed aggregates on the surface of a heavily reinforced concrete dome section of 2-1/2 to 3 feet thickness do not justify immediate initiation of a corrective action. Therefore, the staff finds the applicant commitment to evaluate and resolve the issue via inspection by year 2002 reasonable and acceptable. This was identified as Confirmatory Item 3.10.3.2.2-1 in the previous SER to ensure that the applicant made a formal commitment to perform the inspection by year 2002.

In its July 2, 1999, response to the staff regarding the preceding item, the applicant committed to evaluate the possible containment dome freeze-thaw damage issue as part of the baseline inspection by year 2002. As a result of the applicant's commitment, the staff considers Confirmatory Item 3.10.3.2.2-1 closed.

The applicant considered leaching of calcium hydroxide as a potential ARDM for concrete structural components that are subject to flowing liquid, ponding, or hydraulic pressure because water that contains small amounts of calcium ions (i.e., rain-water or melting snow) can readily dissolve the calcium compounds in concrete when it passes through cracks, inadequately prepared construction joints, or areas inadequately consolidated during construction. The applicant did not consider leaching of calcium hydroxide as a potential ARDM for concrete structural components that are located indoors. The applicant stated that the concrete components potentially subject to leaching of calcium hydroxide were designed in accordance with ACI-318, other relevant ACI standards, and ASTM specifications for low permeability and high compressive strength, which provide the best protection against leaching. Walkdown inspections of the subject structures documented only minor traces of leaching at some locations on these structures. On the basis of the specific characteristics of concrete, the CCNPP architect-engineer and an independent contractor concluded that leaching of calcium hydroxide is not a plausible ARDM for seismic Category I structures at CCNPP. The staff agrees with this position.

Aggressive chemical attack on concrete and corrosion of embedded steel/rebar are considered potential ARDMs for concrete structural components that may be in an aggressive environment that might attack the concrete or embedded steel/rebar, given the following four conditions:

- The fluid-retaining walls and slabs of the IS, which are constantly exposed to a saltwater environment that is considered aggressive;

- The concrete structural components exposed to groundwater, because the groundwater could potentially contain chlorides and/or sulfates that approach or exceed the threshold limits;

- The concrete surrounding the spent fuel pool incorporates a series of monitoring trenches and leak channels to allow detection of any leakage of the borated water in the spent fuel pool that may occur. These could be exposed to concentrated deposits of boric acid residue resulting from collection and/or evaporation of leakage in the leak chases; and

- During the April 1999 Region 1 license renewal Inspection at CCNPP, minor cracking was observed on the exterior containment concrete structure. As result of the inspection, the applicant considers corrosion of embedded steel/rebar a plausible ARDM for exposed exterior concrete containment structures. The applicant proposes to use Procedure MN-1-319, "Structure and System Walkdown," to manage this aging effect.

The applicant stated that aggressive chemical attack on concrete and corrosion of embedded steel/rebar are not considered potential ARDMs for other concrete structural components at CCNPP because of the lack of an aggressive environment. There is no other significant inventory of aggressive chemicals inside the CCNPP structures. There is no heavy industry near the CCNPP site that could release aggressive chemicals into the atmosphere. Because of its proximity to the Chesapeake Bay, the above-grade portion of the exterior walls of some structures may be exposed to an environment containing chloride ions. However, the natural environment created by the bay is not sufficient to promote aggressive conditions on the exterior surface of the above-grade portions of the structures. Additionally, the applicant referred to NUREG-1557, "Summary of Technical Information and Agreements from Nuclear Management and Resources Council [NUMARC] Industry Reports Addressing License Renewal," Table B9 for supporting this conclusion. Table B9 summarizes technical information and NRC/NUMARC (industry) agreements from NRC review of a Class 1 structure industry topical report. The table listed on page B-137 indicates "aggressive chemical attack" is not a plausible ARDM for the applicant's structures, other than the intake structure.

The applicant considered aggressive chemical attack on concrete and corrosion of embedded steel/rebar as plausible for the fluid-retaining walls and slabs of the IS because they are exposed to saltwater that may contain chemicals that might attack the concrete and steel. This item is discussed separately in Section 3.10.3.7.7 of this SER.

Aggressive chemical attack on concrete and corrosion of embedded steel/rebar are considered implausible for the walls and foundations of structures exposed to groundwater because the groundwater chemistry was not considered aggressive during plant construction, and because there is no evidence confirming that the groundwater chemistry has become aggressive since then. The staff agrees with this position.

In NRC Question No. 3.3.36, the staff raised a concern about sustained exposure of below-grade concrete slabs and walls of the IS to groundwater. The applicant's initial response did not give any information indicating the benign chemistry of the groundwater, or historical evidence to demonstrate that the concrete walls and slabs are not subject to aging effects from sustained exposure to groundwater. On March 1, 1999, the applicant provided a facsimile, which was subsequently docketed in NRC meeting summary dated March 19, 1999, that contains the chemical analysis data for the groundwater. The groundwater analysis for three out of four wells indicated that the groundwater chemistry is benign from the standpoint of causing aging related degradation of the exterior of the concrete walls and slab. However, an analysis of one well on the north side indicated very high chloride and sulfate content. In a telephone conference on March 2, 1999, the staff asked the applicant to commit to inspect some portion of the external surfaces of the exterior walls at least once before the start of the period of extended operation. This was identified as Open Item 3.10.3.2.2-1 in the previous SER.

In its July 2, 1999, response to the staff pertaining to this issue, the applicant stated that it considers the environment on the surfaces of the concrete walls of the IS to be more aggressive on the bay water side than on the soil side. The applicant indicated that its opinion is based on the chemical analysis data previously submitted to the staff, as well as on the fact that a lower exposure to oxygen applies to the soil-side concrete. For this reason, the applicant committed to rely on visual inspections performed on the bay water side to verify that no significant degradation of the concrete surfaces on the soil side is occurring. The applicant further stated that the IS/intake cavity walkdowns are periodically performed during refueling outages (when the intake cavities are dewatered) under CCNPP maintenance program procedure MN-1-319. If significant evidence of degradation is discovered on the bay water side, the applicant will assess the potential for similar degraded conditions on the soil side concrete. Additionally, the applicant committed to modifying procedure MN-1-319 to assure the assessment of potential degradation on the soil side. The assessment and any required corrective actions would be conducted in accordance with the CCNPP corrective actions program. Based on the above discussion, the staff finds the applicant's approach for resolving this issue to be a reasonable and acceptable means of identifying and correcting degradation of the concrete surfaces and considers Open Item 3.10.3.2.2-1 closed.

The applicant considered aggressive chemical attack on concrete and corrosion of embedded steel/rebar as implausible for the fluid-retaining walls and slabs behind the spent fuel pool liner because of the quality of the concrete used for construction and the chemical composition of the water in the refueling pool. As discussed above, the concrete used at CCNPP was designed to ensure low permeability and to minimize the likelihood of concrete cracking that would allow water penetration. Such attributes offer good protection against these ARDMs. Additionally, analysis has demonstrated that the effects of boric acid leakage at the concentration present in the spent fuel pool are negligible for concrete or embedded steel/rebar. The staff finds this statement acceptable.

The applicant stated that aggregate reaction is not considered to be a potential ARDM for concrete structural components because the reactivity of aggregates used in CCNPP concrete structures was adequately considered in the original design. The CCNPP concrete design specification states that no aggregate shall be used in concrete until it has been tested for acceptability and verification of the mix. Acceptability of aggregate and source for potential reactivity (chemical) was based on ASTM C-289. The concrete was also subjected to petrographic analysis in accordance with ASTM Designation C-295, "Petrographic Examination of Aggregates for Concrete," which showed that the aggregate was non-reactive. Furthermore, the aggregates used at CCNPP came from sites in Charles County, Maryland, which is not in a geographic region known to yield aggregates suspected of causing or known to cause aggregate reaction. The staff finds these statements acceptable.

The applicant considered the effects of flowing water in two ARDMs: leaching of calcium hydroxide and abrasion and cavitation. Leaching of calcium hydroxide is discussed above. Abrasion and cavitation is not considered to be a potential ARDM for concrete structural components, with the exception of the IS and the associated pipes through which circulating water flows, because no other CCNPP concrete structure is exposed to continuously flowing water. The applicant referred to NUREG-1557, which states that this is a non-significant ARDM for Class I structures other than the IS. Abrasion and cavitation are considered to be potential ARDMs for the fluid-retaining walls and slabs inside the IS because the concrete surfaces are exposed to flowing water. The flow velocity at the intake of a single circulating water pump was calculated to be approximately 12 ft/sec. This velocity is well below the threshold at which abrasion and cavitation would become a concern. The applicant stated that concrete elements subject to this degradation mechanism have been periodically cleaned and inspected as part of the PM program and no significant age-related degradation of the concrete has been identified to date. The staff agrees with this position.

3.10.3.2.3 Weathering of Caulking, Sealants, and Expansion Joints

The structural component types affected by weathering include caulking, sealants, and expansion joints used in the auxiliary building and safety-related diesel generator building structures, TB and IS. The caulking, sealants, and expansion joints located indoors are exposed to the temperature and humidity conditions inside the structures. Those located outdoors are subject to the normal outside atmosphere at the CCNPP. Aging mechanisms associated with weathering of these materials include exposure to sunlight, change in humidity, temperature and pressure fluctuation, and snow, rain, or ice. The effect of weathering on caulking, sealants, and expansion joint filler material is evidenced by a decrease in elasticity, an increase in hardness, and shrinkage. Operating experience indicates that these materials have experienced age-related degradation in the past.

The applicant indicated that weathering of these materials is plausible for AB&SR-DGB, TB, and IS and that, if left unmanaged for an extended period of time, these materials will become brittle and lose the capability to perform the intended functions under current licensing basis conditions.

Caulking, sealants, and expansion joint filler material 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. The applicant stated that caulking, sealants, and expansion joints that perform a fire barrier function in the auxiliary building, the adjacent EDG rooms, the RWT pump rooms, TB, and IS are managed under an existing penetration fire barrier inspection program. The applicant indicated that the program, implemented through CCNPP surveillance test 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. The procedure is performed at least once every 18 months in accordance with Technical Requirements Manual 15.7.10.1. In general, the procedure inspects the penetration seals for damage, cracking, voids, and proper installation. The applicant stated that an audit and inspection performed in 1996 concluded that the CCNPP fire protection program, which included plant walkdowns of some of the fire barrier penetration seals, provides a level of safety consistent with good fire protection practices and NRC regulatory criteria. The applicant stated that operating experience related to this program has shown that aging is a minor contributor to fire barrier penetration seal failures at CCNPP. The applicant asserted that 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. The staff agrees with this statement.

The applicant explained the need for a new aging management program for caulking and sealants that do not function as fire barriers. In NRC Question No. 3.3.7, the staff requested additional information about (1) this new program, including the schedule for implementation, experience of failures of caulking and/or sealants, if any, that resulted in aging degradation of concrete and/or steel components, and (2) corrective actions. The applicant has experienced some leakage of water into various buildings, some of which has been attributed to degraded caulking and/or sealants. Some of this in-leakage involved rain-water or groundwater leakages that resulted in aging degradation of concrete and/or steel components. Various site buildings have been affected, including the north service building, TB, IS, and auxiliary building. Affected components have included electrical panels, lighting fixtures and conduit, and structural steel beams. Degradation was corrected in accordance with the site corrective actions program and included restoration of sealant to minimize or eliminate leakage, restoration or replacement of affected components, and restoration of protective coatings where applicable. In a few cases, concrete was excavated to provide or improve access to affected portions of structural steel beams. On the basis of its experience with failures of caulking and sealants, the applicant has identified the need for a new aging management program for caulking and sealants that do not function as fire barriers. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant stated that this new inspection program will be equivalent or similar to the existing fire barrier inspection program in content, general approach, and details of inspection criteria. The applicant further stated that the inspection interval will be 6 years or less. Since the applicant committed that the new inspection program will be equivalent or similar in content, general approach, and acceptance criteria, to those of the existing fire barrier inspection program, which fully complies with pertinent requirements of Appendix R to Part 50, and the proposed 6 year inspection interval is shown to be adequate based on past nuclear industry operating experience, the staff finds this clarification adequate and acceptable.

In Table 3.3A-4, "Containment System Components Potential and Plausible ARDMs," in Appendix A to the LRA, the applicant listed corrosion/oxidation of the metal portions as the potential ARDM for electrical penetrations (non-EQ). In NUREG/CR-5461, "Aging of Cables, Connections, and Electrical Penetration Assemblies Used in Nuclear Power Plants," the staff concludes that the sealing material, cable insulation, and header plate O-rings in electrical penetrations may be susceptible to aging degradation. The applicant had not addressed the aging effects of radiation and temperature upon these and other non-metallic elements. This was identified as Open Item 3.10.3.2.3-1 in the previous SER.

By letter dated July 2, 1999, the applicant added a new group to Section 3.3A of Appendix A to the LRA which states that radiation and thermal damage are plausible from the possible degradation of the non-metallic portions of the non-EQ electrical penetrations. These penetrations will be subject to the CCNPP Containment Leakage Rate Testing Program (CLRTP) and appropriate actions will be taken if significant leakage from degradation of the non-metallic portion of the electrical penetrations is discovered. The staff considers this response adequate on the basis that the periodic CLRTP will detect degradation of the non-metallic portions of these penetrations due to radiation and thermal damage so that actions can be taken to prevent the technical specification leak rate values from being exceeded. Therefore, Open Item 3.10.3.2.3-1 is closed.

In NRC Question No. 3.3.9, the staff asked the applicant to provide the details of specific national codes and standards (e.g., ACI and AISC), including the editions that will be used to determine repairs and acceptance criteria and, if there are changes with respect to specific national codes and standards previously committed to as part of the initial licensing basis, to describe plans for incorporating these changes in the CCNPP UFSAR. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant responded that whenever repairs are needed, the design, analysis, and construction of structural components requiring repair will be, as a minimum, sized, repaired, and erected in a manner to show their full compliance with the CLB-referenced codes and standards and, as appropriate, will reflect necessary improvements and design margin enhancements which may be adopted by later versions of the codes and standards. The staff considers this response adequate and acceptable.

On the basis of the preceding discussion, the applicant concluded with respect to the weathering of the caulking, sealants and joint filler material for AB&SR-DGB, TB, and IS structures that (1) the caulking, sealants, and expansion joints contribute to providing shelter and protection to equipment, and flood protection as well as fire protection functions to the structures and, therefore, the conditions of these materials must be maintained under all CLB design conditions; (2) these materials are subject to weathering and, if unmanaged, weathering could result in their losing the capability to perform their intended functions under CLB design loading conditions; (3) for caulking, sealants, and expansion joints that function as fire barriers, the penetration fire barrier program will ensure that the fire barrier functions of these materials are maintained; and (4) for caulking, sealants, and expansion joints that do not perform a fire barrier function, a new caulking and sealants inspection program will be implemented to maintain the intended functions of these materials. The applicant further concluded that there is reasonable assurance that the effects of aging from weathering of caulking, sealants, and expansion joint filler material will be managed in such a way that these materials will be capable of performing their intended function consistent with the CLB during the period of extended operation. The staff concurs with this conclusion because the applicant has adequately identified plausible ARDMs for the weathering of caulking, sealants, and expansion joints; the applicant has also proposed to implement periodic inspection programs, which will include measures to detect weathering degradation of the materials, and will cause needed corrective action on filler materials to be taken in a timely manner to ensure that they will be able to continue to perform their intended function consistent with the CLB for the extended period of operation.

3.10.3.2.4 Corrosion of Containment Wall and Dome Liners

The containment wall and dome liners at CCNPP are made of ASTM A36 carbon steel. The liners were erected from a series of individual steel plates that were welded together. Both the plates and the welds are subject to the same potential degradation mechanisms. The inside faces of the wall and dome liners were covered with a protective coating (for corrosion protection) during the construction phase. Since no dissimilar metals were used, galvanic corrosion of liners is judged as not plausible.

The applicant asserted that the effect of pre-compression from prestress forces in the concrete tends to allow very little seepage of groundwater, oxygen, chlorides, or air moisture, all of which can cause corrosion degradation, to penetrate the containment liner and the containment concrete. Also, the containment concrete and the steel liner are not exposed to aggressive chemicals from the outside environment, such as acid rain and groundwater. The applicant stated that steel in the presence of moisture and oxygen will corrode as a result of electrochemical reactions. It stated that chlorides, either from bay water, the atmosphere, or groundwater will increase the rate of corrosion. The applicant concluded that 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. The applicant further concluded that 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. The applicant stated that the effects of corrosion can be mitigated by minimizing the exposure of surfaces of steel liners to an aggressive environment and protecting the liner surfaces with paint or some other coating. The applicant concluded that the effects of corrosion of liners are detectable by visual inspection of liner surfaces and that the degradation of the protective coating can be discovered and monitored by periodic inspection of the carbon steel liners. The staff finds that the applicant's assessment of aging mechanism effects with respect to steel liner corrosion is adequate and agrees with this conclusion.

The applicant stated that the containment liner is periodically examined 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 procedures are currently performed as specified in the containment leakage rate testing program, that is, before 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 Edition, Subsections IWE and IWL, assuming an extension of the interval for the integrated leak rate test to 10 years. The tests specifically address technical specification surveillance requirement 4.6.1.6.3 to visually inspect accessible interior and exterior surfaces of the containment structure and to initiate necessary corrective actions if any portion of the liner plate shows any sign of bulges, wrinkles, cracks, corrosion, flaking paint, or other types of deterioration.

In NRC Question No. 3.3.19, the staff asked if there are any parts of the primary containment structures that are inaccessible for inspection, and, if they are inaccessible, to describe what aging management program will be relied upon to maintain the integrity of the inaccessible areas. The applicant stated that some parts of the containment structures are inaccessible for inspection, and that has not been a licensing concern under the current licensing basis. Inspections of containment structures require the use of the 1992 Edition of ASME Section XI, Subsections IWE and IWL. The applicant also stated that these standards do not require looking at inaccessible areas, unless one is following deteriorated conditions found in adjacent accessible areas. During the February 17, 1999, meeting (NRC meeting summary dated

March 19, 1999) between the staff and the applicant, the applicant provided additional clarification regarding the issue, which, in essence, stated that if conditions adverse to quality are identified in accessible areas adjacent to inaccessible areas, the applicant would take appropriate measures to identify the scope and extent of the adverse conditions, and the applicant's corrective action would include disposition of the condition adverse to quality in the inaccessible area as well. As an example of this process, the applicant cited Section 5.7, page 3, in Appendix A to the LRA which referred to a situation in which portions of four buried pipe lines were inspected. The staff finds that the applicant's explanation is adequate and acceptable.

The applicant stated that 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 the liner plate. The original joint sealant, Thiokol polysulfide, was found to be deteriorating. Blistering of the joint and corrosion of the liner were observed at the joint as evidence of water intrusion. High-density silicon elastomer (HDSE) was used to replace the deteriorating Thiokol polysulfide as an effective corrective action. Also, to improve the sealing function, the HDSE was being placed a minimum of 3 inches into the joint after removing some compressible material. The corrective action was completed for Unit 1 in 1996 and will be completed for Unit 2 during the 1999 refueling outage. On the basis of this CCNPP operating experience, the applicant concluded that for the existing program, STP-M-665 can be relied upon to adequately inspect the liner corrosion and detect deficiencies in the area of liner-to-seal material and initiate needed corrective actions. At the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the staff asked the applicant how it planned to manage potential degradation of the horizontal liner in the containment from potential water intrusion through concrete basemat cracks and asked about the condition of the 18-inch concrete basemat. The applicant stated that the containment system engineers perform a walkdown and visual inspection of the containment, including the floors, every outage when the containment is open. The applicant further stated that no cracks have ever been discovered in the 18-inch-thick, steel-reinforced, high-density concrete floors that were considered large enough to so affect the liner that it would fail to perform its safety function. On the basis on this confirmation of the soundness of the material condition of the concrete floor of the containment, the staff finds that the applicant's conclusion about its management of liner aging effects is adequate and acceptable.

On the basis of the preceding detailed discussion, the applicant reached the following conclusions with respect to corrosion of the containment wall and dome liners: (1) the containment wall and dome liners support a pressure boundary or fission-product retention-barrier function in the event of any postulated design-basis event, and their integrity and functionality must be maintained under all CLB conditions; (2) corrosion of the inside surface of the containment wall and dome liner plates is plausible because of the possible degradation of the external protective coatings and exposure to water and oxygen and, if left unmanaged, corrosion could eventually result in the liner plates not being able to perform their intended function under CLB conditions; and (3) periodic visual inspections of the containment wall and dome liners will continue to be performed in accordance with surveillance test procedures STP-M-665-1/2, and these inspections will identify and document significant coating degradation and/or the presence of corrosion as well as initiate timely corrective actions pursuant to the CCNPP corrective action procedure. The applicant further found reasonable assurance that the effects of aging from 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. The staff finds that the applicant's AMPs discussed above are acceptable because these programs cover the containment wall and dome liners subject to an AMR; coating prevents corrosion by minimizing environmental exposure; the parameter monitored is coating degradation, which is a condition directly related to potential loss of liner material; the carbon steel liner surfaces cannot experience degradation unless the paint/coating degrades and, thus, observing and confirming that the paint/coating is intact is an effective way to ensure that liner surfaces have not degraded and intended functions are maintained; effects of corrosion are detectable by visual techniques and the inspections used are periodic and should provide for timely detection of aging effects; acceptance criteria ensure that any coating degradation is reported and evaluated according to site corrective action procedures; and operating experience shows that these programs are effective. Additionally, the staff finds that the walkdowns (as described above), when implemented properly will ensure that degraded conditions from corrosion of steel liners are identified and corrected so that the containment wall and dome liners will be capable of performing their intended functions under all CLB conditions.

3.10.3.2.5 Corrosion of Steel

The components of building structures that are fabricated from steel are known to corrode in the presence of moisture and oxygen. This group of components is identified with an asterisk in Tables 3.3A-1, 3.3B-2, 3.3C-2, 3.3D-2, and 3.3E-2 of Appendix A, to the LRA. The environment to which these components are exposed varies with their installed locations and ranges from a controlled environment to CCNPP site outdoor temperature, humidity, wind, and precipitation. There is no heavy industry near CCNPP to add chemicals to the atmosphere but, owing to close proximity to Chesapeake Bay, the steel components located outdoors could be exposed to condensation. Additionally, some of the steel components are located near the spent fuel pool (SFP), where condensation in the presence of oxygen could lead to oxidation. The applicant stated that carbon steel located in these areas may be subjected to more severe local environments.

The applicant stated that steel in the presence of moisture and oxygen will corrode as a result of electrochemical reactions. It stated that chlorides, either from seawater, the atmosphere, or groundwater, will increase the rate of corrosion. The applicant concluded that corrosion is plausible for carbon steel components of the CCNPP building structures. It concluded that if the corrosion discussed is left unmanaged for an extended period of operation, the resulting loss of material could lead to the inability of these steel components to perform their intended function under CLB design loading conditions. The staff finds that the applicant's assessment of aging mechanisms and their effects with respect to steel corrosion is reasonable and sufficient in scope.

The applicant stated that 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 coatings. It further stated that the effects of corrosion of steel are detectable by visual inspection of external component surfaces and that the degradation of the protective coating can be discovered and monitored by periodic inspection of carbon steel components. The staff agrees with the applicant's statement about the mitigation and discovery of steel corrosion.

Administrative procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of corrosion of steel or of conditions that would allow corrosion to occur, such as deterioration of paint or pooled water for building structural components, by performance of visual inspections during plant walkdowns. The purpose of this program is to provide direction for the performance of structure and system walkdowns and for the documentation of walkdown results. The applicant's procedure MN-1-319 requires responsible personnel to perform periodic walkdowns of their assigned structures and systems during every refueling outage and to schedule walkdowns to ensure that every structure will receive a walkdown at least every third outage. These walkdowns are intended to assess the condition of the CCNPP building SSCs so that any abnormal or degraded condition will be identified and documented, and corrective actions will be taken before these SSCs lose the ability to perform their intended functions. The MN-1-319 procedure has been improved recently through incorporation of additional guidance on specific activities to be included in the scope of the structural walkdowns and, according to the applicant, additional enhancements will be made to the procedure to incorporate the following: (1) help to the walkdown personnel to determine whether the intended functions will continue to be met as required by the applicable CLB and (2) approval authority when significant departure from the inspection scope or schedule occurs. This was identified as Confirmatory Item 3.10.3.2.5 -1 in the previous SER.

In its July 2, 1999, response to the staff with respect to the preceding item, the applicant stated that procedure MN-1-319 is in the process of being enhanced to help walkdown personnel to determine whether intended functions will continue to be met as required by the CLB. The enhancements to the procedure are in the form of more detailed and explicit inspection requirements for components and potential ARDMs that may not have been included or readily identified by existing walkdown inspection criteria. The following changes will be addressed: (a) clear stipulation in procedure MN-1-319 to require inspection of reinforced concrete walls within concrete structures other than containment; (b) specific identification of the field-erected tanks within the scope of MN-1-319 walkdowns; (c) additional visual inspection criteria specific to detecting leakage near the refueling water tank (RWT) penetrations; and (d) modification of procedure MN-1-319 to include additional visual inspection criteria specific to the perimeter seal. The applicant also indicated that procedure MN-1-319 will be revised to add guidance regarding approval authority for significant departures from the specified walkdown inspection scope and schedule. The staff finds that these commitments are acceptable and fully resolve this issue. Therefore, Confirmatory Item 3.10.3.2.5-1 is closed.

Since the containment emergency sump cover and screen contain wire mesh for trapping debris that could potentially be swept up by the safety injection pump, and since the wire mesh obstructs the view of the structural steel that supports the grating and screen, the routine walkdowns performed under the MN-3-100 procedure cannot be relied on for discovery of corrosion of this component. The applicant proposed to continue to implement surveillance test procedure STP-M-661-1/2, "Containment Emergency Sump Inspection," at every refueling outage according to the requirement of plant technical specifications. The applicant asserted that 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 and these inspections would detect any degraded paint condition that 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 screens and the recording of detected deficiencies and initiation of appropriate corrective actions according to the CCNPP corrective action program. The applicant concluded that the visual inspection performed in accordance with STP-M-661-1/2 will ensure that degraded conditions from corrosion of the cover and the screen (made of structural steel) are detected and corrected so that they will be capable of performing their intended functions under all CLB conditions. The staff finds this surveillance test procedure proposed by the applicant for managing the aging effects of the emergency sump cover and screen acceptable because it augments other proposed aging effects management programs with enhanced surveillance requirements to ensure that the degradation of the exterior carbon steel surfaces of the containment emergency sump and screen will be detected and that needed corrective actions will be implemented on a timely basis.

The applicant considered corrosion of embedded steel/rebar as a potential ARDM for the external surfaces of the foundations and walls (below grade) of the auxiliary building from exposure to groundwater. Since the foundation mats of the two diesel generator buildings are above the groundwater elevation, this ARDM is not considered plausible for these buildings. The applicant also stated that the natural environment created by the Chesapeake Bay is not sufficient to promote aggressive conditions, so corrosion of embedded steel/rebar is not a potential for the above-grade portion of the auxiliary and safety-related diesel generator buildings. Corrosion of embedded steel/rebar is a potential ARDM for the internal surfaces of fluid-retaining walls and slabs (behind the spent fuel pool [SFP] liner only) because it is exposed to borated water from leaks in the SFP liner. No other internal surfaces are likely to be exposed to a corrosive environment on a regular basis.

However, the applicant stated that since the quality of concrete and continuity of concrete cover over the embedded steel/rebar play important roles in preventing corrosion and if embedded steel/rebar is not exposed to an aggressive environment (low pH or high chlorides with oxygen available), then the age-related degradation from corrosion of these items will be insignificant. The staff agrees with this statement. With respect to the fluid-retaining walls and slabs supporting the SFP liner, as well as the foundations and below-grade walls of the auxiliary building, the applicant stated that they were constructed with concrete conforming to American Concrete Institute (ACI) codes and American Society for Testing and Materials specifications ensuring low permeability. Additionally, the auxiliary building was designed in accordance with ACI Specification 318, which specifies a reinforcement distribution that minimizes crack development; thus, the concrete cover over embedded steel components will effectively prohibit exposure of embedded steel components to potentially corrosive environments. The applicant also stated that during construction, analyses of groundwater at the CCNPP site indicated neutral pH, with concentrations of aggressive chemical species well below the levels that can lead to corrosion of embedded steel/rebar, and the effects of boric acid leakage on reinforced concrete were analyzed in response to leaks at the Unit 2 refueling pool noted in 1994 and 1995. An engineering evaluation of the applicable concrete standards and tests on rebar concluded that the corrosion rates for embedded steel resulting from boric acid leakage are negligible. On the basis of these determinations, the applicant concluded that corrosion of embedded steel/rebar in concrete structural components of the auxiliary building should not be plausible. The staff agrees with this finding.

In NRC Question No. 3.3.3, the staff asked the applicant if the results of earlier inspections (1994 and earlier) indicated any particular trend in the incidence of coating degradation or corrosion of steel. The applicant stated that it was not aware of any trends associated with the incidence of coating degradation or the corrosion of steel. During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant, by way of providing clarification, stated that on the basis of a discussion with the applicant's coating specialist in the civil engineering unit at CCNPP, the frequency of coating degradation/failure or corrosion of steel has been fairly constant with no increasing or decreasing occurrences. The applicant also indicated that, for example, the inspections conducted inside the containments each refueling outage generally identify 20 to 35 areas that require coating restoration, and this number has been fairly consistent over the last several years. The staff finds this clarification acceptable.

On the basis of the preceding detailed discussion, the applicant concluded with respect to the corrosion of structural steel for building structures that (1) structural steel components defined above serve a passive intended function and their integrity must be maintained under all CLB conditions, (2) corrosion of steel is plausible because of possible degradation of the external protective coatings and exposure to water and oxygen, (3) periodic visual inspections of coated surfaces of building structural elements and initiation of appropriate corrective actions for identified degraded coatings will continue to be performed in accordance with MN-3-100 and MN-1-319 procedures, respectively, and these inspections will identify and document significant degradation and/or the presence of corrosion, and (4) periodic visual inspections of the structural steel members of the containment emergency sump cover and screen will continue to be performed in accordance with procedures STP-M-661-1/2, and significant coating degradation or corrosion will be discovered and appropriate corrective actions will be taken in accordance with the CCNPP corrective action program. The applicant further concluded that there is reasonable assurance that the effects of aging from the corrosion of steel components will be managed in such a way that building structures will be capable of performing their intended functions consistent with the CLB during the period of extended operation. The staff agrees with the applicant's conclusion because: these programs cover the entire scope of building structural components subject to an AMR; use of coating prevents corrosion by minimizing environmental exposure; the parameter monitored is coating degradation, which is a condition directly related to potential loss of materials; the exterior carbon steel surfaces cannot experience degradation without degradation of paint/coating and, thus, observing and confirming that the paint/coating is intact is an effective method to ensure that external surfaces have not corroded and the components' intended functions are maintained; effects of corrosion are detectable by visual techniques and inspections are carried out on a periodic basis and should provide for timely detection of aging effects; acceptance criteria adopted ensure that any coating degradations are reported and evaluated according to site corrective action procedures; and operating experience shows that these programs are effective.

3.10.3.2.6 Corrosion of the Refueling Pool/Spent Fuel Pool Liners and PCSR

The refueling pool liner and the refueling pool permanent cavity sealing ring (PCSR) are constructed from SA-240 Type 304 stainless steel plates and are resistant to electrochemical corrosion in the refueling pool environment. The applicant indicated that the corrosion rate of this steel is extremely small in a borated fuel pool water environment; therefore, electrochemical corrosion is negligible for the refueling pool liner and the PCSR. The applicant also said that since the liner and the 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 the PCSR. However, the heat-affected zones of the welds are potential sites for sensitization and sensitized Type 304 stainless steel may be susceptible to the inter-granular stress corrosion cracking (IGSCC) in a boric acid solution. Conditions that may lead to IGSCC are elevated temperature, chloride content, boric acid concentration, oxygen concentration, and degree of sensitization.

The SFP liner is constructed of welded plates of Type 304 stainless steel material. The stainless liner is not designed as a load-bearing structural component; it was designed only as a leaktight barrier to prevent the loss of spent fuel cooling water. The concrete behind the liner welds was formed in such a way that a channel was created to allow detection of any leakage that may occur through the welds or liner base material. Water has been collected from these leak chases for many years. Both the plate material and the associated weld materials are susceptible to stress corrosion cracking. 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.

The SFP liner is not exposed to a corrosive environment under normal operating conditions. Therefore, stress corrosion cracking is not a major concern except at the heat-affected zones in and around welds. Conditions that may contribute to the occurrence of IGSCC are elevated temperature, chloride content, boric acid concentration, oxygen concentration, and degree of localized sensitization. Initiation and propagation of cracks in the stainless material are the typical effects of IGSCC and, if it is left unmanaged for an extended period of time, the resulting leakage of the liner could lead to its inability to perform the intended pressure boundary function under CLB design loading conditions. The applicant indicated that IGSCC of the stainless steel refueling pool liner and the PCSR could result in detectable leakage. If IGSCC of the refueling pool liner and the 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 the CLB design loading conditions. The applicant's operating experience indicates that the general condition of the refueling pool is good with no apparent aging. According to the applicant, there has been minimum leakage to date, except at one location in Unit 2, where the leak may have originated from drain pipes, not from the liner or the PCSR. During the February 17, 1999, meeting, (NRC meeting summary dated March 19, 1999), the applicant stated that the refueling pool leakage, which was discovered earlier, would not significantly affect the strength of the refueling pool concrete slab. The staff agrees with this conclusion. The drain-pipe leakage was evaluated for its effects on the rebar in the concrete and was shown to have negligible effects on concrete strength. There has been no evidence of IGSCC on the liner or the PCSR welds. Two welds closest to the high-stress region of the PCSR were visually inspected 2 years after the PCSR was installed, without finding any IGSCC.

During the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant was asked to explain how it manages the aging effects of refueling pool liner IGSCC. The applicant stated that the effects of IGSCC can be mitigated by minimizing the exposure of external surfaces of steel to an aggressive environment and that the effects of IGSCC could cause the refueling pool liner or the PCSR to leak. The applicant also stated that since the liner and the PCSR do not serve any structural function except as fluid-retaining boundaries, detecting and, if needed, measuring and trending leakage from the refueling pool should provide an effective aging management tool, and if any leakage is detected, the applicant plans to take corrective measures to restore the refueling pool integrity. The staff finds this approach acceptable.

The applicant's aging management program for the refueling pool liner and the PCSR consists of detecting, and if needed, measuring and trending leakage from the refueling pool and the PCSR, which, in turn, would lead to discovery of IGSCC so that corrective measures can be taken before loss of the liner function. The applicant stated that routine inspections are performed on system components in accordance with CCNPP administrative procedure MN-1-319. It stated that these walkdowns will enable discovery and management of the effects of corrosion through visual inspections.

In NRC Question No. 3.3.13, the staff inquired if the transfer tube/bellows and containment sump recirculation penetrations were accessible for periodic inspections, and if they were not accessible, the applicant was asked to discuss the rationale for concluding that the functionality and integrity of these items are assured and maintained during the license renewal period. The applicant stated that the fuel transfer tube and the containment sump recirculation penetrations are constructed from stainless steel, and no ARDMs were determined to be plausible for these components. Therefore, no inspections are credited for aging management of these components. It also stated that the transfer tube/bellows and containment sump recirculation penetrations are not readily accessible for periodic inspection, but an inspection is possible and the fuel transfer tube from the refueling canal was visually examined in April 1995. This inspection verified that there were no indications of damage or corrosion. The staff finds that Question No. 3.3.13 is fully resolved.

On the basis of the information presented above, the applicant concluded that (1) refueling and spent fuel pool liners and the PCSR support a fluid leakage boundary or fission-product retention barrier function in the event of any postulated DBE and their integrity must be maintained under all CLB conditions, (2) IGSCC on the inside surface of the liner plates or the PCSR is plausible because of potential sensitization of the steel at weld locations and presence of borated water, and if it is left unmanaged, could result in the pool liners or the PCSR not being able to perform their function under the CLB conditions, and (3) periodic walkdowns of the containment and auxiliary building will continue to be performed in accordance with procedures MN-1-319, PEO 0-67-2-O-M, and OI-24D, which will identify and document the presence of leaks that may be due to IGSCC. The staff agrees with these conclusions.

On the basis of the preceding proposed periodic walkdown programs, the applicant concluded that there is reasonable assurance that the effects of aging from IGSCC on the pool liners and the PCSR will be managed in such a way that they will be capable of performing their intended function consistent with the CLB during the extended period of operation. The staff finds that this aging management program, including its periodic walkdown program, is acceptable because the program covers the full scope of the refueling pool and spent fuel pool liners and PCSR, which are subject to an AMR; the periodic walkdowns to be implemented will identify leakages of the pool liners and the PCSR; the parameter monitored is related to IGSCC type degradation; the proposed inspections are periodic and should provide for timely detection of IGSCC-induced aging effects; the acceptance criteria are adequate to ensure that these pool liners will perform their function and if any IGSCC related degradation is detected, it will be reported and evaluated according to CCNPP corrective action procedures.

3.10.3.2.7 Degradation of Fluid-Retaining Walls and Slabs Subject to Aggressive Chemical Attack

The applicant stated that this category of structural elements includes the IS fluid-retaining walls and slabs that could be subject to aggressive chemical attack on the concrete and corrosion of the embedded steel. The fluid-retaining walls and slabs serve as structural and/or functional support to safety-related equipment, shelter/protection to safety-related equipment, and flood protection barriers (internal flooding event).

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.

The applicant determined that aggressive chemical attack on concrete and corrosion of embedded steel rebar were plausible for the IS's 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.

The applicant indicated that concrete, being highly alkaline (pH > 12.5), is vulnerable to degradation by strong acids and that 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, on the other hand, may provide an acceptable degree of protection against mild acid attack. Chlorides and sulfates of sodium, potassium, and magnesium may attack concrete, depending upon their concentrations (an industry report notes that minimum degradation threshold limits for concrete are 500 ppm for chlorides or 1500 ppm for sulfates). Sulfate attack can produce significant expansion stresses within the concrete, leading to cracking, spalling, and strength loss. Once established, these conditions allow further exposure to aggressive chemicals. The applicant concluded that 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.

NRC Question No. 3.3.36 raised the concern of sustained exposure of below-grade concrete slabs and walls of the IS to groundwater. This concern and the applicant's response are discussed in Section 3.10.3.2.2 of this SER.

3.10.3.2.8 Corrosion of Steel Components Inside Miscellaneous Tanks and Valve Enclosures

The applicant stated that it will rely on administrative procedure MN-1-319, "Structure and System Walkdowns," for the discovery of corrosion of the steel components in the No. 12 CST, No. 21 FOST, and AFW valve enclosures. Under this procedure, walkdowns will be performed every 6 years and may be done more frequently for material condition assessments, system reviews, or plant modifications. Walkdowns will not only identify corrosion but also the potential effects of corrosion, such as damaged supports, in addition to identifying conditions that may accelerate corrosion, such as degraded protective coatings and accumulated moisture. The identification of corrosion resulting from the walkdowns will be documented and resolved by the CCNPP corrective actions program.

Structure walkdowns are performed using MN-1-319 every refueling outage and walkdowns are scheduled to ensure that every structure at CCNPP will receive a walkdown at least every third refueling outage. The refueling outage interval for CCNPP is 2 years. Hence, a structural performance assessment will be performed on each structure at least once every 6 years. The staff finds that this minimum walkdown frequency of once every 6 years is adequate to assess the condition of the steel components of the No. 12 CST, No. 21 FOST, and AFW valve enclosures.

The staff finds that administrative procedure MN-1-319 is adequate to ensure the discovery and management of significant corrosion of the steel components in the No. 12 CST, No. 21 FOST, and AFW valve enclosures, because it is consistent with 10 CFR Part 50 (Appendix B).

3.10.3.2.9 Weathering of Grout

The grout at the containment's tendon-bearing plates is exposed to outdoor weather conditions and is susceptible to weathering. Aging mechanisms associated with weathering of the grout include exposure to sunlight, change in humidity, temperature and pressure fluctuation, and snow, rain, or ice. The effect of weathering on grout is evidenced by cracking and spalling of the bearing plate grout.

The applicant indicated that weathering of the grout under the bearing plates is plausible and determined that most degradation of the grout results from water entering cracks in and around the grout and freezing. The effects of weathering of grout are detectable by visual inspection, and periodic visual examination would provide for discovery of degraded grout so that corrective action could be taken to preclude the effects of weathering from affecting the intended function of the grout.

A containment tendon surveillance, which is periodically performed on the post-tension system, includes visual examination, lift-off force measurements, tendon wire tensile strength testing, and analysis of the sheath filler grease. As a means for managing the weathering effects on the grout, the applicant proposed to perform periodic tendon surveillance according to STP-M-663-1/2 procedures. The surveillance program will verify the structural integrity of the end anchorage and adjacent concrete exterior surfaces. If any adjacent concrete shows indication of abnormal material losses and degradation, an engineering evaluation will be initiated to demonstrate the ability of the containment structure to continue to perform its function in accordance with TS 3.6.1.

On the basis of the preceding discussion, the applicant concluded with respect to the weathering of the grout at the containment vertical tendon base plates that (1) the grout provides structural support to the base plates of vertical tendons and its integrity must be maintained under all CLB conditions, (2) weathering of the vertical tendon grout is plausible, and (3) periodic visual inspections of the grout will continue to be performed in accordance with the CCNPP STP-M-663-1/2 procedures and these inspections will discover the effect of weathering and ensure that the necessary evaluations are performed to demonstrate the ability of the containment structure to perform its design function. The applicant further concluded that there is a reasonable assurance that the effects of aging from 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. The staff agrees with this conclusion because the applicant has (1) adequately identified plausible ARDMs for the weathering of the containment vertical tendon bearing plate grout and (2) proposed to continue the periodic containment tendon inspection program, which will (a) include measures to detect weathering degradation of the vertical tendon anchor plate grout and (b) cause needed corrective actions to be taken in a timely manner to ensure that the containment will be able to continue to perform its intended function consistent with the CLB.

3.10.3.2.10 Aging Management Programs for Intake Structure and Sluice Gates

The applicant stated that the current PM tasks call for the periodic draining of IS cavities during refueling outages to scrape and wash the saltwater tunnel/cavity walls (i.e., the fluid-retaining walls and slabs), that visual inspections are performed after cleaning, and that repairs are made as required. The applicant further committed to modifying the PM to provide more specific guidance on inspection for degradation (e.g., cracking, rust staining, spalling) that may be a result of ARDMs. The PM program is governed by CCNPP administrative procedure MN-1-102, "Preventive Maintenance Program." Any conditions adverse to quality discovered during these inspections are documented in IRs in accordance with the CCNPP corrective action program. The applicant believes that such a modified PM would be sufficient to ensure that the IS will remain capable of performing its intended functions under all CLB conditions. The staff finds the applicant's planned modified PM to be reasonable and acceptable. Furthermore, the indication of no significant age-related degradation of concrete from the applicant's operating experience associated with performance of the PM tasks has reinforced the validity of the PM tasks.

The IS contains steel components and they are subject to corrosion. Corrosion was recognized as a potential degradation mechanism for all structural steel components of the IS, and therefore all exposed structural steel surfaces in the IS except for galvanized steel such as grating, checkered plate, and metal decking, were shop-painted or field-painted during plant construction. CCNPP administrative procedure MN-1-319, "Structure and System Walkdowns," provides for discovery of steel corrosion or conditions that would accelerate corrosion for the IS by performing visual inspections during plant walkdowns. One of the objectives of the walkdown program is to assess the condition of the CCNPP SSCs so that any abnormal or degraded condition will be identified, documented, and corrected. The walkdown program inspects the following elements related to aging management: (1) items related to specific ARDMs such as corrosion, (2) effects that may have been caused by ARDMs such as damaged supports, concrete degradation, anchor bolt degradation, and leakage of fluids, and (3) conditions that could allow progression of ARDMs such as degraded protective coatings, leakage of fluids, presence of standing water or accumulated moisture, and inadequate support of components (e.g., missing, detached, or loose fasteners and clamps). The program includes a walkdown checklist specifically for the IS that contains a section targeted at structural steel components. For the steel components, a visual inspection is required for corrosion, rust stains, and flaking/bubbling of protective coatings. A structure performance assessment is currently required for Category I structures at CCNPP at least once every 6 years. Based on the above discussion, the staff finds that the applicant's walkdown program for steel components of the IS is reasonable and acceptable.

The IS sluice gates are used to isolate the circulating water pump inlet bays from the saltwater pump suction pits for maintenance purposes. Each sluice gate consists of a gate, a gate frame, a stem, a lift mechanism, and two wire rope/chain assemblies. The lower portions of the wire rope/chain assemblies are subject to a saltwater environment. The upper portions of the wire rope/chain assemblies are subject to outdoor environmental conditions. The sluice gates experienced corrosion in the past. Moderate corrosion of the sluice gates was observed in 1986, and, as a result, new sluice gates were installed. 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 IS cavities dewatered. The wire rope/chain assemblies and associated fittings 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. The applicant committed to either modify the existing PM tasks or initiate new PM tasks to add specific instructions for inspection of these subcomponents. The staff finds that the new or modified PM tasks will provide reasonable assurance that the effects of aging from corrosion will be managed so that the sluice gates will be capable of performing their intended function, consistent with the CLB during the period of extended operation.

3.10.3.2.11 Degradation of Neutron-Absorbing Materials

The spent fuel racks of CCNPP Unit 1 use a neutron-absorbing material consisting of a boron carbide powder in a Fiberglas matrix (carborundum sheet). The Unit 2 spent fuel racks use a different neutron-absorbing material consisting of fine particles of boron carbide in a silicon polymer matrix (boraflex). These neutron-absorbing sheet materials contribute to the intended function of the fuel storage racks by absorbing neutrons in the SFP. Experience has shown that 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 neutron-absorbing sheets could result in an increase in the reactivity of the SFP configuration which, in turn, may lead to loss of function of the spent fuel storage racks. The degradation of either type of neutron-absorbing material can be monitored by periodic testing of sample coupons that are representative of the materials in the SFP storage racks.

CCNPP ETP 86-03R, "Analysis of Neutron-Absorbing Material in Spent Fuel Storage Racks," was developed for detecting degradation of neutron-absorbing materials. 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. The sample coupons are a conservative representation of the neutron-absorbing materials in the SFP storage racks. Proper implementation of the program will enable the applicant to detect various degrees of neutron-absorbing material degradation and to document and correct unacceptable results in accordance with the CCNPP corrective action program. CCNPP will continue using this coupon surveillance program as the primary means for monitoring the condition of the neutron-absorbing materials in the SFP storage racks.

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 4 years. Additionally, one accelerated sample packet of each material type is removed from the SFP every 2 years. The program described above will be modified to (1) reevaluate the adequacy of the sampling intervals in monitoring carborundum and boraflex condition through the period of extended operation and (2) refine the process for scheduling removal of sample packets from the SFP.

The applicant stated that the coupon surveillance program provides for periodic monitoring of the condition of neutron-absorbing material in the SFP. The cumulative results of the coupon surveillance program indicate that the neutron-absorbing sheets have experienced no significant degradation 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. The 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 heat in the spent fuel in the racks . Since the inspection holes in the spent fuel pool 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. The applicant stated that, based on its past surveillance data, there is no evidence that such erosion is occurring at locations other than the immediate vicinity of the sample holder inspection holes. The applicant also stated that its four year long-term sampling, and its two year accelerated sampling intervals were selected based on a 40-year service life for the SFP storage racks. The evaluation schedule for the period of extended operation will remain the same, unless the applicant determines that a shorter inspection interval will be used. Although there is no need for an evaluation of the adequacy of the sampling intervals, considering the above discussed surveillance results, the applicant stated that the program will be modified to reevaluate the timetable and refine the scheduling process for removing sample packets from the SFP. The applicant further stated that the program will identify and document degradation of the carborundum and boraflex materials, and will ensure that appropriate actions are taken in a timely manner if significant neutron-absorbing capability is lost. The applicant concluded that 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. With the applicant's modification of the coupon surveillance program to (1) provide for periodic monitoring of the condition of neutron-absorbing material in the SFP and (2) reevaluate the timetable and refine the scheduling process for removing sample packets from the SFP, the staff agrees with this conclusion.

3.10.3.2.12 Foundation Settlement

The applicant discussed the containment basemat settlement. The applicant based its discussion on the bearing capacity of the foundation medium and a conservatively evaluated average basemat bearing pressure. It also considered the foundation medium type extracted from the plant FSAR and concluded in its LRA that long-term settlement including differential settlement at CCNPP containment structures was not plausible for the following reasons: (1) ample bearing capacity compared to the computed basemat bearing pressure, (2) use of a permanent pipe drain system, and (3) an engineering judgment that the basemat tends to uniformly settle as a rigid body. The staff finds that the applicant's justification for drawing this conclusion is both reasonable and acceptable.

The applicant discussed the potential settlement as an ARDM for the auxiliary building and safety-related diesel generator building structures. The foundation for the Auxiliary Building is situated primarily on the undisturbed soil of Miocene deposit that is capable of supporting loads on the order of 15 to 20 kips per square foot (ksf) as compared to the 8 ksf for the design contact pressure of the Auxiliary Building mat. For the SR Diesel Generator Building, the ductbank for EDG, the EDG Room and RWT Pump Rooms, engineered soil structures incorporating compacted fill materials provide foundation support. Quality assurance and quality control measures imposed during backfill placement assured that unexpected settlement of plant structures would not take place at CCNPP. Additionally, 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" to minimize any changes to the site conditions that could affect settlement of the foundations for these structures. BGE's engineering analysis indicated that most of the predicted settlement is expected in terms of uniform settlement which has no adverse effect on structural components of the Auxiliary Building and any differential settlement is expected to be small and have negligible effect. The applicant further stated that a walkdown inspection of the Auxiliary Building performed in 1994 found no indication of structural damage due to settlement. Based on the technical justification given above, the applicant concluded that settlement is not a plausible ARDM for these buildings. The staff considers the applicant's justification acceptable.

The applicant considered settlement of the IS as a potential ARDM. However, a detailed review indicated that the settlement is not plausible for the IS on the basis of the following site-specific justification. The ultimate bearing capacity of the foundation stratum is in excess of 80,000 psf, and the allowable bearing capacity is 15,000 psf. The design contact pressure of the IS foundation is 2,500 psf. A maximum post-construction settlement of 0.5 inch was predicted in the original IS design. Most of the predicted settlement is in terms of uniform settlement, which has no adverse effects on the structural components of the IS. A small fraction of the predicted 0.5 inch settlement will be in terms of differential settlement. Settlement is so small that its effect on structural components is judged to be negligible. On this basis, settlement was determined to be implausible for any structural components of the IS. This conclusion is supported by a walkdown of the IS, performed in 1994, which found no indication of structural damage from settlement. The staff agrees with this conclusion.

3.10.3.2.13 Structural Walkdown Procedures (MN-1-319)

Procedure MN-1-319 (reference NRC meeting summary dated June 26, 1998 and the applicant's presentation Slides Nos. 24 and 34) indicates that the system engineers and PE-MCEU personnel perform, and evaluate the results of, the concrete examination, and that they will look for gross degradations. Applicable 10 CFR Part 50 (Appendix B) requirements will ensure that the personnel performing the walkdowns and any subsequent technical evaluation are appropriately qualified and that qualification and standards of acceptability (acceptance criteria) are established. For concrete structures, ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," provides recommendations for qualifying personnel and evaluation criteria. The applicant may use these or equivalent criteria for qualifying its concrete examination personnel and for establishing its acceptance criteria.

3.10.3.2.14 Intake Channel and Baffle Structures

With respect to the issue of including the intake channel and baffle structures within the scope of the LRA, the applicant stated that the functional requirements of the intake channel and baffle structures do not meet any of the scoping criteria. At the February 17, 1999, meeting (NRC meeting summary dated March 19, 1999), the staff asked the applicant to explain its basis for excluding the intake channel and the baffle structure from the scope of an AMR. The applicant indicated that operating instruction 29 contains operating temperature limitations for the salt water/service water heat exchanger; thus, the contribution of the baffle structure/intake channel in getting "cooler" bay water from the bottom stratum of the bay is bounded by these limitations. The staff reviewed pertinent portions of the applicant's operating instruction 29 and concluded that the applicant's explanation of the basis for excluding the features from the scope of an AMR are adequate and acceptable.

3.10.3.2.15 Cable Trays and Ventilation Ducts

In 10 CFR 54.21(a)(1)(i), the NRC requires that cable trays and ventilation ducts that perform an intended function as described in 10 CFR 54.4 without moving parts or without a change in configuration or properties, be identified and listed as items subject to an AMR. The staff asked the applicant to confirm that these items are subject to an AMR and to discuss how the review was or will be implemented. The applicant stated that cable trays are discussed in Section 3.1 of Appendix A to the LRA, and that the cable tray supports include the cable trays themselves. The applicant indicated that the term "outside containment" covers all areas within the scope of license renewal outside containment. The applicant further confirmed that HVAC systems within the scope of license renewal are discussed in Sections 5.11A, 5.11B, and 5.11C of Appendix A to the LRA, and these systems include all safety-related ducting. The staff finds that this clarification is adequate and acceptable.

3.10.3.3 Time-Limited Aging Analyses

3.10.3.3.1 Containment Prestressing Force TLAA

In the discussion of an aging management program for managing corrosion of tendons/ prestressing losses, the applicant indicated a need to revise the 40-year curves representing the lift-off force vs. time to reflect a 60-year operating life. The applicant stated that, as a result of this revision, selected tendons may have to be retensioned to meet their revised lift-off force requirements.

In general, a typical TLAA for prestressing forces in a containment should consist of the following elements when using the requirements of 10 CFR 54.21(c)(1)(ii):

> Predicted tendon lift-off force (F_p) vs. time (T) curves for each of the three groups of tendons (i.e., vertical, hoop, and dome tendons) having similar characteristics (e.g., alignment, orientation, lockoff forces, and environmental conditions (such as temperature, humidity, anchorage exposure)). Regulatory Guide 1.35.1 provides guidance on how to perform a trending analysis. If the trending analysis of the measured tendon force (F_m) vs. time (T) curve is above the lower bound predicted curve extended up to the end of a license renewal term, the extended F_p curve (for the group) may be used for comparison with the tendon lift-off forces measured during future surveillances. If the trending of F_m indicates that it will be below the extended F_p curve within the current license or during the extended license term, a systematic program for retensioning the tendons needs to be developed to ensure that the minimum prestressing requirement of the current licensing basis is met up to the end of the extended term.

The staff recognizes that the applicant may not have a sufficient database from past inspections to reliably project the tendon prestressing force to 60 years. Consequently, as a result of discussions with the staff, the applicant proposed to continue the current AMPs to provide sufficient means for managing the effects of aging for the period of extended operation, as provided in 10 CFR 54.21(c)(1)(iii), by relying on the tendon surveillance program required by Section 50.55a(b)(2)(ix), which is part of the current licensing basis. The staff concludes that continuing the current AMPs into the period of extended operation will assure that the tendons will maintain their intended functions during the renewal period and finds this approach acceptable.

In a letter to the applicant dated August 12, 1999, the staff requested specific information in four areas related to Open Item 3.10.3.2.1-1 (see Section 3.10.3.2.1 of this SER for a discussion of this open item). In letters to the NRC dated July 2 and September 28, 1999, the applicant responded to this open item and the specific requests in the August 12, 1999 letter from the staff. The information requested by the staff and the applicant's response is summarized below

1. Parameters monitored or inspected as per 10 CFR 50.55a(b)(2)(ix)(B)

UFSAR Section 15.6 (part of the Technical Requirements Manual) discusses the applicant's current surveillance program. Although 10 CFR 50.55a(b)(2)(ix)(B) is limited to the evaluation of prestressing forces in consecutive surveillances, the applicant committed to inspect all of the parameters listed in 10 CFR 50.55a(b)(2)(ix).

2. Acceptance criteria such that the projected tendon force trending remains above the predicted lower limit

   ASME Code Section XI, IWL-3221 provides acceptance criteria for prestress loss for each type of tendon. The measurement results of the current examination, when compared to the measurement results from the previous examination should indicate a prestress loss such that predicted tendon forces meet the minimum design prestress forces at the next scheduled examination. The applicant stated that if this criterion is not met, the options are acceptance by evaluation (as provided in IWL-3222) or acceptance by repair/replacement (as provided in IWL-3223).

3. Corrective actions that include systematic re-tensioning of tendon population to ensure the adequacy of prestressing force

   Potential corrective actions by the applicant include "bootstrapping," or increasing the tension in all or part of the tendons, replacing selected tendons with new tendons, and reanalysis.

4. Operating experience as applicable to tendon force monitoring

   Throughout the industry, other plants have observed prestressing wire corrosion, end anchorage failures, water in the vertical tendons, and greater- than- expected relaxation from solar heating. The applicant found broken wires during a 1997 inspection. Since 1997, the applicant performed research on tendon sheathing filler material; ran tests on grease replacement methods; wrote a specification for, and received bids on, tendon replacement; and contracted for additional analyses to verify and/or refine the UFSAR values for containment strength.

On the basis of the information summarized above, the staff concludes that the applicant has an adequate AMP to ensure that the actual prestressing forces for the three types of tendons will remain above the lower bound limits during the period of extended operation and considers Open Item 3.10.3.2.1-1 closed.

3.10.3.3.2 Containment Liner Plate Fatigue Related TLAA

The applicant stated that the containment liner plate fatigue is a TLAA item with a limiting number of thermal cycles during the licensed life of the plant. In Section 2.1.3.5 of Appendix A to the LRA, the applicant stated that the analysis will be projected to the end of the period of extended operation by the year 2012. The detailed staff evaluation of this item is appears in Section 4.1.3 of the SER.

3.10.3.3.3 TLAA Related to the Criticality Analysis of Unit 1 Spent Fuel Pool

The applicant stated that the criticality analysis for the Unit 1 spent fuel pool (SFP) is a TLAA item due to age-related depletion of boron-10 used as a neutron absorbing material between spent fuel assemblies. In Section 2.1.3.7 of the LRA, the applicant stated that the TLAA is currently being updated and will accommodate the period of extended operation. The detailed staff evaluation of this item is provided in Section 4.1.3 of this SER.

3.10.4 Conclusions

The staff has reviewed the information submitted in Section 3.3A, "Primary Containment Structure"; Section 3.3B, "TB Structure"; Section 3.3C, "IS"; Section 3.3D, "Miscellaneous Tank and Valve Enclosures"; and Section 3.3E, "Auxiliary Building and Safety-Related Diesel Generator Building Structures," of Appendix A to the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the primary containment structures, turbine building structure, IS, tank and valve enclosures, and auxiliary building and safety-related diesel generator building structures will be adequately managed so that there is reasonable assurance that these buildings and structures will perform their intended functions in accordance with the CLB during the period of extended operation.

3.11 Component Supports, Cranes, and Electrical Commodities

3.11.1 Introduction

The applicant described its AMR of the component supports, cranes and electric commodities for license renewal in four separate sections of its LRA. These four sections are Section 3.1, "Component Supports"; Section 3.1A, "Piping Segments That Provides Structural Support"; Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes"; and Section 6.2, "Electric Commodities." The staff reviewed these sections of Appendix A to the LRA to determine whether the applicant had submitted adequate information to meet the requirements stated in 10 CFR 54.21(a)(3) for managing aging effects of the component supports, fuel handling equipment (FHE) and other heavy load handling cranes (HLHCs), and electrical commodities (ECs) for license renewal.

3.11.2 Summary of Technical Information in the Application

3.11.2.1 Component Supports, Crane Systems, and Electric Commodities Subject to an Aging Management Review

3.11.2.1.1 Component Supports

Section 3.1 of Appendix A to the LRA contained a description of component supports that are subject to the an AMR. As described in Section 3.1.1.1 (Component Supports Commodity Scoping"), a "component support" is defined as the connection between a system, or a component within a system, and a plant structural member. All component supports that provide support to plant systems and components that are within the license renewal scope are also considered to be within the scope of license renewal. According to the applicant (as described in Table 3.1-1 of Appendix A to the LRA), component supports associated with 48 systems are to be addressed in accordance with Section 3.1. In Table 3.1-2 of Appendix A to the LRA, the total population of component supports, based on the associated systems and components they support, are grouped into four categories (piping supports; cable raceway supports; heating, ventilation and air conditioning (HVAC) ducting supports; and equipment supports) and into 19 component support types. The grouping of component support types is based on similarities of physical characteristics, loading condition, and environment.

3.11.2.1.2 Piping Segments That Provide Structural Support

Section 3.1A of Appendix A to the LRA contains a description of the piping segments that provide supports to the safety-related piping systems and are subject to an AMR. As described in Section 3.1A.1.1, these piping segments include all piping segments beyond the safety-related/non-safety-related (SR/NSR) boundary to the first seismic restraint(s), and perform the intended passive function of providing structural support to the safety-related piping and seismic anchor (or equivalent). All fluid systems that contain safety-related piping and have the potential for safety-related/non-safety-related functional boundaries with seismic Category I boundaries extending beyond them are within the scope of license renewal and are listed in Table 3.1A-1 of Appendix A to the LRA.

3.11.2.1.3 Fuel Handling Equipment and Other Heavy Load Handling Cranes

Section 3.2 of Appendix A to the LRA contains a description of FHE and other HLHCs that are subject to an AMR. Section 3.2.1 states that the scope of license renewal under this section covers the evaluation of (1) components involved in fuel handling and transfer and (2) cranes that routinely lift heavy loads over safety-related components. On the basis of the system level scoping results, components associated with five systems related to FHE and HLHC are identified to be within the scope. These five systems are the spent fuel storage, refueling pool, new fuel storage and elevator, fuel handling, and cranes.

3.11.2.1.4 Electrical Commodities

Section 6.2 of Appendix A to the LRA addresses the ECs for the CCNPP. ECs include the following structural enclosures for electrical equipment, which provide support and protection of the electrical equipment located within them: miscellaneous panels, motor control center (MCC) cabinets, switchgear/disconnect cabinets, bus cabinets, circuit breaker cabinets, local control station panels, battery terminals and charger cabinets, and inverter cabinets. The applicant stated that ECs provide structural support to system components contained in the equipment to ensure electrical continuity of power, control, or instrumentation signals. Cables are excluded from this evaluation. ECs vital to plant safety are designed as Class 1E so that they will maintain their integrity under a safe-shutdown earthquake, design-basis winds, or disturbances in the external electrical system.

3.11.2.2 Effects of Aging

In the LRA, component-ARDM combinations were grouped together where there are similar characteristics and the discussion is applicable to all components within the group. In general, for each component-ARDM combination, the applicant documented its AMR results by addressing the following items: (1) general description of component-ARDM combination, (2) materials and environment, (3) aging mechanism effects, (4) methods to manage aging effects, (5) AMPs, and (6) demonstration of aging management.

3.11.2.2.1 Component Supports

The applicant evaluated the applicability of age related degradation mechanisms (ARDMs) for the component supports and identified all potential ARDMs in Table 3.1-3 of Appendix A to the LRA. As a result of the plant-specific AMR of component supports, the applicant determined that the aging effects from the following six ARDMs (out of all potential ARDMs listed in Table 3.1-3 of Appendix A to the LRA) are determined to be "plausible" and should be subject to an AMR: general corrosion of steel, loading due to hydraulic vibration or water hammer, loading due to rotating/reciprocating equipment, loading due to thermal expansion, elastomer hardening, and stress corrosion cracking of high strength bolts.

On the basis of the combination of component types and ARDM characteristics, the applicant grouped all component supports (which are constructed of structural steel and are subjected to the AMR) and the associated potential ARDMs into seven groups. These seven groups are (1) piping supports (general corrosion of steel, loading due to hydraulic vibration or water hammer, and loading due to thermal expansion of piping/component); (2) cable raceway supports, HVAC supports, and equipment supports (general corrosion of steel); (3) elastomer vibration isolators (elastomer hardening); (4) metal spring isolators and fixed bases (outside containment)/LOCA restraints (loading due to rotating/reciprocating equipment); (5) frames and saddles/LOCA restraints (loading due to hydraulic vibration or water hammer); (6) frames and saddle/ring foundation for flat-bottom vertical tanks (loading due to thermal expansion of piping/component); and (7) frames and saddle (inside containment)/LOCA restraints (stress corrosion cracking of high-strength bolts).

The applicant's approach for identifying "plausible" ARDMs of component supports involves two steps: baseline walkdowns (or inspections) and follow-on activities (or actions). The baseline walkdowns are usually one-time activities that are performed to identify and determine whether the plausible ARDMs are actually occurring for the potentially affected supports. According to the LRA, the entire population of supports in a given group does not have to be subject to baseline inspection. The basis for not performing walkdowns to the entire population of supports is that if these 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 inspection 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 assess baseline conditions of such supports.

The follow-on activities are conducted repetitively. If no evidence of plausible ARDMs is identified during the baseline walkdowns, the follow-on activities may consist of periodic, documented walkdowns by system engineers to ensure that this condition continues. If evidence of significant aging effects is found for certain groups of support/ARDM combination during the baseline walkdowns, follow-on actions consist of aging management activities (these activities may involve the initiation of corrective actions) that are formulated to address the condition discovered during the baseline inspection.

3.11.2.2.2 Piping Segments That Provide Structural Support

Section 3.1A.2 of Appendix A to the LRA indicates that the plausible ARDMs for each piping segment beyond the safety-related/non-safety-related boundary are the same ARDMs as those identified for the safety-related portion of the respective piping in the systems listed in Table 3.1A-1. The associated LRA section for each potentially affected piping system is also noted in that table.

3.11.2.2.3 Fuel Handling Equipment and Other Heavy Load Handling Cranes

The applicant evaluated the applicability of ARDMs for the FHE and HLHC, and identified all potential ARDMs in Table 3.2-1 of Appendix A to the LRA. As a result of the plant-specific AMR of the FHE and HLHC, the applicant determined that the aging effects due to the following five ARDMs (out of 11 potential ARDMs listed in Table 3.2-1 of Appendix A to the LRA) are "plausible" and should be subject to an AMR: general corrosion/oxidation, fatigue, wear, corrosion from boric acid, and mechanical degradation/distortion.

From the system-level scoping process performed by the applicant, five systems (spent fuel storage, refueling pool, new fuel storage and elevator, FHE, and cranes) related to the FHE and

HLHC are identified within the scope of license renewal. In addition, this section of the LRA also covers the structural load-handling devices designed to transfer the loads of the reactor vessel head to the polar crane (PC). Structures and components subject to an AMR will encompass those structures and components (1) that perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in configuration or properties, and (2) that are not subject to periodic replacement based on a qualified life or specified time period. By applying this scoping process to all components related to the five systems mentioned earlier, the applicant determined that the portions of the FHE and HLHC that are within the scope of license renewal and subject to an AMR includes 57 structural components and their supports. Because nine of the FHE and HLHC components (such as PC girder, spent fuel cask handling crane rail/support girders, etc.) were already addressed for their intended functions as parts of building structures, the total number of components (including supports) that are subject to an AMR is reduced to 48. These 48 components (including supports) and the related potential and plausible ARDMs are listed in Table 3.2-1 of Appendix A to the LRA.

On the basis of the combination of component types and ARDM characteristics, the applicant grouped all components (including supports) and the associated potential ARDMs into the following four groups: (1) general corrosion/oxidation for FHE and HLHC carbon steel components (except the RV cooling shroud structural support members), (2) general corrosion/oxidation and corrosion due to boric acid for the RV cooling shroud structural support members, (3) fatigue for the PC rails, and (4) fatigue, wear, and mechanical degradation/ distortion for wire rope and only wear for carbon steel chains.

3.11.2.2.4 Electrical Commodities

The applicant evaluated the applicability of ARDMs for the components subject to AMR. The applicant determined that the aging effects due to the following plausible ARDMs should be managed for ECs: electrical stressors, wear, fatigue, general corrosion, and dynamic loading for some components. The applicant's evaluation is summarized in Table 6.2-3 of Appendix A to the LRA. The LRA also contains information on the operating experience of the ECs regarding aging degradation.

3.11.2.3 Aging Management Programs

The applicant identified the following AMPs for the component supports, piping segments that provide structural support, FHE and HLHCs, and ECs for license renewal in the LRA.

3.11.2.3.1 Component Supports and Piping Segments That Provide Structural Support

For the AMR of component supports within the scope of license renewal, the applicant, as shown in Table 3.1-4 of Appendix A to the LRA, will use nine AMPs to manage the aging effects that are identified as plausible. These nine programs and the application of these programs are summarized below:

- Snubber Visual Inspection Surveillances

  Snubber Visual Inspection Surveillances Program is an existing program and is credited with follow-on discovery activity for snubber supports within the scope of the evaluation of the snubber commodity.

- Structure and System Walkdowns (MN-1-319)

  Program MN-1-319 is an existing program and is credited for the follow-on discovery activities for component supports covered by completed seismic verification program (SVP) walkdowns, and for component supports inspected by the additional baseline walkdowns (if no active ARDMs are found during additional walkdowns). The applicant applies this walkdown procedure to groups 1 through 6 of support and ARDM combinations.

- Control of Shift Activities (NO-1-200)

  Program NO-1-200 is an existing program and is credited for the follow-on discovery activities relating to component supports for which no active ARDMs are found during the baseline walkdowns. This program 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. During shutdowns, 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 in the area. Site deficiencies are documented to ensure appropriate corrective action is taken. The applicant applies this walkdown procedure to groups 1 through 6 of support and ARDM combinations.

- Ownership of Plant Operating Spaces (NO-1-107)

  Program NO-1-107 is an existing program and is also credited for the follow-on discovery activities relating to component supports for which no active ARDMs are found among the baseline walkdowns. This program 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 area and provide a point of contact for any individual who finds deficiencies or any concern with that area. Owners are required to periodically inspect their area 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. Areas subject to inspection include containment, turbine building, auxiliary building, IS, and outside areas. The applicant applies this walkdown procedure to groups 1 through 6 of support and ARDM combinations.

- Section XI Inservice Inspection Program

  The Section XI inservice inspection (ISI) program is an existing program that is credited for both baseline and follow-on discovery activities. The applicant applies this program to groups 1, 2, and 4 through 7 of support and ARDM combinations.

- Preventive Maintenance Checklists

  PM checklists are part of the plant's PM program. Two of these existing checklists need to be modified to provide for the inspection of metal spring isolators and fixed bases inside containment. The applicant credits these two checklists for the group 2 combination of supports and ARDMs.

- Preventive Maintenance Repetitive Task 10672001

  The PM repetitive task will be used to manage the aging of the SFP piping supports. The PM program is currently in place for inspection of the SFP filter and demineralizer vessel/strainer. The PM repetitive task will implement a procedure that will be modified to provide specific guidance on inspecting piping supports for signs of boric acid corrosion. Corrective actions resulting from these inspections will ensure that these piping supports will remain capable of performing their intended functions under all CLB conditions.

- Additional Baseline Walkdowns

  The additional baseline walkdowns is a new program that is credited for additional baseline discovery activities for component supports not covered or only partially covered by the seismic verification program (SVP) or the ISI program, where conditions prevented extrapolation of results to cover these component supports. The applicant applies this procedure to groups 1, 2 and 7 of support and ARDM combinations.

- Plant Modification

  A new plant modification is credited for the replacement of the control room HVAC air handler elastomer-type isolator supports spring-type isolators. The applicant credits this modification for the group 3 support and ARDM combinations.

In addition, the applicant credited its SVP for the baseline walkdown to detect and document the condition of component supports of the mechanical and electrical equipment that is on the CCNPP safe-shutdown equipment list. According to the applicant, the SVP was developed based on the seismic qualification utilities group (SQUG) guideline (Generic Implementation Procedure 2 or GIP-2), which has been found acceptable, with limitation, by the staff (SSER dated May 22, 1992).

3.11.2.3.2 Piping Segments That Provide Structural Support

Section 3.1A.2 of Appendix A to the LRA indicates that the piping segments beyond the safety-related/non-safety-related boundary will be managed by the same AMPs credited in the sections of the LRA for the safety-related portion of the piping system listed in Table 3.1A-1. The applicant further states that these AMPs will manage the aging mechanism so that the intended function of the piping segments beyond the safety-related/non-safety-related boundary up to the first seismic anchor will be maintained consistent with the current licensing basis during the period of extended operation.

3.11.2.3.3 Fuel Handling Equipment and Other Heavy Load Handling Cranes

For the AMR of fuel handling equipment and other heavy load handling cranes within the scope of license renewal, the applicant, as shown in Table 3.2-2 of Appendix A to the LRA, will use seven AMPs to manage the aging effects that are identified as plausible. These seven programs and the application of these programs are summarized below:

- Operation Section Performance Evaluations and Associated Operating Instructions (PE 0-81-1-O-Q and OI-25A, and PE 0-81-2-O-C and OI-25C)

  These programs are existing programs and are credited for discovery and management of general corrosion-oxidation effects in carbon steel parts of the spent fuel handling machine (SFHM), reactor refueling machine (RRM), and associated components by performing periodic visual inspections. The applicant applies these programs to group 1 crane subcomponents and ARDM combinations.

- Load Handling Procedure (MN-1-104)

  Program MN-1-104 is an existing program and is credited for (1) discovery and management of general corrosion-oxidation effects in carbon steel parts of FHE and HLHC components by performing visual inspections and (2) discovery and management of fatigue, wear, and mechanical degradation-distortion effects in wire rope and carbon steel chains by performing visual inspections. The applicant applies this procedure to groups 1 and 4 crane subcomponents and ARDM combinations.

- Maintenance Repetitive Task 10992001 (20992000), "Perform NDE on Polar Crane Rails"

  These existing repetitive tasks are credited for discovery and management of fatigue effects in carbon steel PC rails by performing NDE. The applicant applies this maintenance task to the group 3 crane subcomponents and ARDM combinations.

- Operations Section Performance Evaluations and Associated Operating Instructions (OI-25A and PE 0-81-1-O-Q, OI-25B and PE 0-81-3-O-Q, Operating Instruction 25C and PE 0-81-2-O-C, and OI-25E)

  These programs are existing programs and are credited 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 machine and transfer carriages, respectively, by performing periodic visual inspections. The applicant applies these performance evaluations to group 4 crane subcomponents and ARDM combinations.

- Maintenance Repetitive Tasks 10812007 (20812009), 10812013 (20812014), 20992010, 00992009, 10992010 (20992002), 10992007, 00992015, 00812007, and 00812008

  These PM tasks are credited for discovery and management of fatigue, wear, and mechanical degradation-distortion effects in wire rope for the fuel upending machine and transfer carriages, RRM main hoists, RRM auxiliary hoists, spent fuel cask handling crane (SFCHC), PC, and IS semi-gantry crane (ISSGC), respectively, by performing visual inspections. The applicant applies these performance evaluations to the group 4 crane subcomponents and ARDM combinations.

- PM and Repetitive Tasks 00992009, 10992010 (20992002), 10992007 and 10642031(20642030)

  These repetitive tasks will be modified to explicitly present inspection requirements. They are credited for discovery and management of general corrosion-oxidation effects in carbon steel parts of the SFCHC, polar crane, ISSGC, and reactor vessel head lift rig, by performing visual inspections. The applicant applies these maintenance tasks to the group 1 crane subcomponents and ARDM combinations.

- BACI Program, MN-3-301

  Procedure MN-3-301 is to be modified to provide for the discovery and management of general corrosion-oxidation and corrosion due to boric acid for the reactor vessel cooling shroud structural support members by performing visual inspections. The applicant applies this program to group 2 of support and ARDM combinations.

3.11.2.3.4 Electrical Commodities

In Table 6.2-4 of Appendix A to the LRA, the applicant listed the following AMPs for ECs. The table also summarizes the application of these programs for discovery and management of aging effects for ECs

- Certain checklists associated with existing repetitive tasks governed by CCNPP maintenance program procedure MN-1-102, "Preventive Maintenance Program"
- New repetitive tasks and associated checklists governed by CCNPP maintenance Program Procedure MN-1-102, "Preventive Maintenance Program"

In summary, Tables 3.1-4, 3.2-2, and 6.2-4 of Appendix A to the LRA summarize the application of these AMPs and/or maintenance programs for mitigation, discovery, and managing the ARDMs of component supports (including piping segments that provide structural support), FHEs and HLHCs, and ECs. The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended functions of these elements would be maintained during the period of extended operation, consistent with the CLB, under all design loading conditions.

3.11.2.4 Time-Limited Aging Analyses

Section 2.1, "Time-limited Aging Analyses," of Appendix A to the LRA indicates that there are no time-limited aging analyses (TLAAs) applicable to the component supports, FHE systems, HLHC systems, and ECs.

3.11.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information submitted in Sections 3.1, 3.1A, 3.2, and Revision 1 of Chapter 6.2 of Appendix A to the LRA regarding the applicant's demonstration that effects of aging will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation. These sections in the application address component supports (including piping segments that provide structural support), FHE and HLHC structures and components, and ECs. The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER.

By letters dated April 8, 1998, and March 11, 1999, the applicant submitted its LRA and subsequent Revision 1, respectively. The technical information of how the aging effects of the in-scope component supports, FHE and HLHC systems, and ECs are to be identified and managed is given in Sections 3.1, 3.1A, 3.2, and Revision 1 of Chapter 6.2 of Appendix A to the LRA. The applicant, as described in Appendix A, applies its scoping process to systems and components that are within the scope of license renewal. The rule for license renewal requires that structures and components subject to an AMR encompass those structures and components that (1) perform an intended function, as described in 10 CFR 54.4, without moving parts or without a change in a configuration or properties, and (2) are not subject to periodic replacement on the basis of a qualified life or specified time period. On this basis, the applicant identified items that are subject to an AMR within the context of its license renewal application. In general, for each component-ARDM combination, the applicant documented its AMR results by addressing the following items: (1) general description of component-ARDM combination, (2) materials and environment, (3) aging mechanism effects, (4) methods to manage aging effects, (5) AMPs, and (6) demonstration of aging management.

By letters dated August 26, 1998, and September 7, 1998, the staff issued several requests for additional information (RAIs) after completing the initial review. By letters dated November 4, and 19, 1998, the applicant responded to the staff's RAIs.

3.11.3.1 Effects of Aging

3.11.3.1.1 Component Supports (Including Piping Segments That Provide Support)

All component supports (piping supports, cable raceway supports, HVAC ducting supports, equipment supports, metal spring isolators and fixed bases, frames and saddles/LOCA restraints (both inside and outside containment), and frames and saddles for flat-bottom vertical tanks) are constructed of structural steel, except for elastomer vibration isolators, which are constructed of carbon steel and natural or synthetic rubber, and ring foundations for flat-bottom vertical tanks, which are constructed from reinforced concrete. All component supports (except for ring foundation for flat-bottom vertical tanks) are located inside the containment and other climate-controlled buildings. Inside the containment, the maximum design ambient air temperature and relative humidity are 120 °F and 50 percent, respectively. In the other buildings, the design ambient temperature is in the range of 110 °F, and there are no design humidity requirements for the plant areas outside the containment. The applicable ARDMs identified by the applicant are general corrosion of steel, loading due to hydraulic vibration or water hammer, loading due to thermal expansion of piping/component, loading due to rotating/reciprocating equipment, stress corrosion cracking of high-strength bolts, and elastomer hardening. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds that the applicant has identified relevant ARDMs and that no credible additional ARDMs exist.

The operating experience information in the application indicates that the component supports have, in general, performed well and have exhibited no age related degradation that impaired their intended function, except that three events of support damage caused by water hammer occurred in the main feedwater and low-pressure safety injection (LPSI) systems. The cause of these events has been appropriately evaluated by the applicant. Design modifications were made and operating procedures were changed to reduce the potential for water hammer or damage caused by water hammer in the future. On the basis of a review of the applicant's operating experience, as discussed above, the staff finds that the applicant has adequate operating procedures and an effective program to manage age related degradation of component supports.

Aging Management Review

The applicant identified that the effects of general corrosion of structural steel (piping supports, cable raceway supports, HVAC ducting supports, and equipment supports) should be managed for license renewal (groups 1 and 2 of support/ARDM combinations). The staff concurs because the carbon steel materials are exposed to air with moisture.

The applicant identified that the effects of elastomer hardening should be managed for the elastomer vibration isolators (group 3 support/ARDM combinations). The staff agrees because extended exposure of elastomer material to light, heat, oxygen, ozone, water, or radiation can cause scission or cross-linking of the polymer chains forming the elastomer material. All these environmental conditions will cause degradation of the material (such as lowering tensile strength and brittleness of elastomer).

The applicant identified that the effects of loading due to rotating/reciprocating machinery are plausible and should be managed for the metal spring isolators, fixed bases, and LOCA restraints (group 4 of support/ARDM combinations). The staff agrees because these loading effects from machine vibration could cause degradation of the steel load path and concrete, and concrete cracking in the vicinity of the equipment anchorage. Consequently, component support strength will be reduced if the ARDM is allowed to progress unmanaged.

The applicant identified that the effects of loading from hydraulic vibration or water hammer are plausible and should be managed for the piping supports, frames, saddles, and LOCA restraints (groups 1 and 5 of support/ARDM combinations). The staff agrees because the aging effects caused by this ARDM could cause loss of weld integrity, loosening of bolted connections, 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.

The applicant identified that the effects of loading from thermal expansion of components are plausible and should be managed for the piping supports, frames, saddles, and ring foundations of flat-bottom vertical tanks (groups 1 and 6 support/ARDM combinations). The staff agrees because the aging effects from this ARDM could cause 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.

The applicant also identified that the effects of stress corrosion cracking of high-strength bolts are plausible and should be managed for the frames, saddles, and LOCA restraints (group 7 of support/ARDM combinations). The staff agrees because the aging effects from this ARDM could cause 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 equipment or component.

The staff agrees that there are no additional ARDMs for these systems.

As stated in Section 3.11.3 above, from its initial review of Section 3.1 of Appendix A to the LRA, the staff issued a number of RAIs in the letter dated September 7, 1998. The applicant responded to these RAIs on November 19, 1998. The staff's evaluation of the applicant's responses is summarized below:

(1) In NRC Question No. 3.1.1, the staff raised a concern regarding the inclusion of component supports of System 68, "Spent Fuel Storage System," in the scope of license renewal. The applicant responded that spent fuel pool component supports are addressed in the cranes and fuel handling commodity evaluation. However, the applicant did not discuss the AMR of spent fuel storage component supports in Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes," of Appendix A to the LRA. The applicant supplemented the response in a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), and stated that there are no component supports for the spent fuel storage system in the scope of license renewal. By letter dated September 28, 1999, the applicant revised its previous RAI response accordingly.

(2) In NRC Question No. 3.1.6c, the staff raised a concern that when structural steel members (known as "supplementary steel members," such as a piece of I-beam) are added between a component support (e.g., the HVAC duct support type labeled "rod hanger trapeze supports") and the building structural elements (e.g., walls and steel members) to transfer loads (from component supports to the building structure), the aging effects on this type of supplementary steel members should be managed as part of component supports.

The applicant responded on November 19, 1998, to the staff's question and supplemented the response in a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999). The applicant referred to its response to NRC Question No. 3.1.9. In that response, the applicant stated that there are some instances of HVAC duct support frames made of structural steel members. These structural steel members should be included as support types for HVAC ducting supports in Tables 3.1-2 and 3.1-3 of the LRA. The aging management for HVAC ducting supports is included with group 2 discussions on pages 3.1-23 through 3.1-29 of Appendix A to the LRA. In a followup conference call on February 26, 1999, the applicant confirmed that the HVAC ducting supports identified in Tables 3.1-2 and 3.1-3 in Appendix A of the LRA included the structural steel members and therefore, there is no need to revise these two tables. On the basis of the information submitted by the applicant, the staff considers this NRC question resolved.

(3) In NRC Question No. 3.1.15b, the staff asked the applicant to demonstrate how the aging effects of concrete cracking due to vibration loads will be managed, since the concrete cracks will affect the ultimate strength of both the expansion anchors and embedded anchors. The applicant's response did not discuss concrete cracking caused by vibration loads or how the aging effects caused by concrete cracking from vibration loads will be

managed. In a followup discussion, the applicant provided information concerning this issue, and stated that loading due to vibration is considered plausible for component supports including embedded anchors. The applicant also identified AMPs to manage vibration loads. The applicant's administrative procedure MN-1-319, which is discussed in Section 3.1.3 of this SER, addresses inspection procedures for concrete around embedded anchors. Based on the applicant's procedure MN-1-319, the staff finds the applicant's aging management program adequate and acceptable to resolve this issue.

3.11.3.1.2 Fuel Handling Equipment and Other Heavy Load Handling Cranes

The components of the FHE and HLHC systems (such as spent fuel shipping cask support platform, incore instrumentation (ICI) trash racks, spent fuel pool platform, spent fuel inspection elevator, new fuel elevator, fuel upending machine and transfer carriage, RRM, SFHM, SFCHC, PC, ISSGC, transfer machine jib crane, and load handling equipment) are constructed of carbon steel, galvanized steel, stainless steel, and nickel-based alloys. (Some of the FHE and HLHC components, such as PC girders, SFCHC rail/support girders, refueling pool reinforced concrete [RC], refueling pool stainless steel liner, fuel transfer tube stainless steel liner, spent fuel pool stainless steel liner, spent fuel pool RC, spent fuel pool storage racks, and new fuel storage racks, are addressed for their structural intended functions as parts of the buildings in which they are housed.) Most of the in-scope structural components are either exposed to climate-control in environments inside the containment and auxiliary buildings or are submerged in water. The applicant considered a comprehensive list of potential ARDMs and identified the applicable ARDMs as general corrosion/oxidation, fatigue, mechanical degradation/distortion, corrosion caused by boric acid, and wear. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds the applicant's approach of identifying ARDMs an acceptable means to satisfy the license renewal rule because aging effects are a result of ARDMs.

The operating experience information in the application indicates that the FHE and HLHC systems have, in general, performed well and have exhibited no age related degradation that impaired the system function, except that during the 1996 Unit 1 refueling outage, four fillet welds connecting structural members on the fuel upending machine in the refueling pool were found to have failed. The evaluation performed by the applicant determined that original joint design, original fabrication, and subsequent changes to machine operations led to low-cycle fatigue failure of the welds. Corrective actions, including addition of stiffeners at the weld joints and use of dual hydraulic cylinders for machine operation (to eliminate future fatigue failure), were implemented for both fuel upending machines in Units 1 and 2.

The applicant determined that the effects of general corrosion/oxidation for FHE and HLHC carbon steel components should be managed for license renewal. The staff agrees that because the carbon steel materials are exposed to moisture and oxygen, temperature and corrosion will cause the protective coatings to fail and lose their ability to adhere to the corroding surfaces. Also, the outdoor saltwater atmosphere could cause the protective coatings of structural members of the ISSGC to fail.

The applicant determined that the general corrosion/oxidation and corrosion from boric acid should be managed for the RV cooling shroud structural support members. The staff agrees because carbon steels are susceptible to significant acceleration of general corrosion effects when exposed to boric acid. Leakage of boric acid from RV head penetrations can result in the formation of concentrated deposit of boric acid in the form of crystals at the anchorage of the RV cooling shroud because of evaporation caused by the high temperature of the RV head. This kind of damage will lead to the loss of load-carrying cross-sectional area and weaken the structural integrity of affected members.

The applicant determined that the effects of fatigue should be managed for the PC rails. The staff agrees because the short PC rail sections installed at the expansion joints contain flame-cut holes and are subject to repeated loading whenever the PC is used for lifting loads. These repeated loads could cause low-cycle fatigue of the PC rails.

The applicant determined that the effects of fatigue, wear, and mechanical degradation/distortion should be managed for the wire ropes. The staff agrees because the wire ropes are subject to both low-cycle and high-cycle repeated loads. The fatigue damage from these repeated loads will result in cracking and breakage of individual wire and strands that make up the rope. Also, wear from relative motion between the rope and groove can cause damage of the rope.

The staff agrees that there are no additional ARDMs for these systems.

As stated in Section 3.11.3 of this SER, from its initial review of Section 3.2 of Appendix A to the LRA, the staff issued a number of RAIs in the letter dated August 26, 1998. The applicant responded to these RAIs on November 4, 1998. The staff's evaluation of the applicant's responses is summarized below:

(1) In NRC Question No. 3.2.1, the staff asked the applicant to provide the basis for excluding the spent fuel shipping cask washdown pit (a structural component in the spent fuel pool system) and the fuel transfer tube from the scope of license renewal. In its response to this question, the applicant stated that the spent fuel shipping cask washdown pit and the fuel transfer tube are within the scope of license renewal and are subject to an AMR. The fuel transfer tube is addressed in Section 3.3A, "Primary Containment Structure," of Appendix A to the LRA. The RC of the spent fuel cask washdown pit is addressed in Section 3.3E, "Auxiliary Building and Safety-Related Diesel Generator Building Structures," of Appendix A to the LRA. The spent fuel cask washdown pit liner is constructed of stainless steel and primarily experiences the ambient atmospheric conditions of the auxiliary building spent fuel area. The stainless steel liner is wetted with borated and/or demineralized water during spent fuel storage cask loading operations. Because of the relatively mild atmosphere and infrequent wetting, there are no plausible ARDMs for the stainless steel liner and, therefore,

no discussion of AMPs in Appendix A to the LRA. However, the staff reviewed Section 3.3E of Appendix A to the LRA and found that the LRA (Section 3.3E and Table 3.3E-2) did not specifically state that the AMR for the spent fuel shipping cask washdown pit is covered in the license renewal scope for the auxiliary building. In a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), the applicant supplemented the response and stated that the cask washdown pit is a feature of the auxiliary building. However, the cask washdown pit does not have any intended function in accordance with 10 CFR 54.4 and, therefore, is not within the scope of license renewal and is not subject to an AMR. On the basis of this clarification, the staff considers this issue resolved.

(2) In NRC Question No. 3.2.13(1), the staff asked the applicant to justify why "fatigue," which is identified as a plausible ARDM for the PC rails, is not plausible for other crane rails. In its response, the applicant stated that, as depicted on Table 3.2-1 of Appendix A to the LRA, fatigue of crane rails is plausible only for the rails of the PC; therefore, programs to manage the effects of fatigue described under group 3 are only required for those particular crane rails. The applicant's response did not satisfy the staff's concern, because no justification was given. During the onsite meeting held on February 16–18, 1999 (NRC meeting summary dated March 19, 1999), the applicant clarified that the holes in the PC rails are flame cut after fabrication, and that holes on other rails are cut during fabrication and stress relieved. Therefore, fatigue is not plausible for other crane rails. On this basis, the staff agrees and this issue is resolved.

(3) In NRC Question No. 3.2.13(2), the staff asked the applicant to justify why the aging effects from wear, fatigue, and mechanical degradation/distortion (group 4, "Aging Management") are not applicable to other crane components and subcomponents. In its response to this question, the applicant stated that, as depicted on Table 3.2-1 of Appendix A to the LRA, group 4 only addresses the unique plausible ARDMs applicable for wire rope. Additional clarification was provided during the onsite meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999). The applicant stated that moving subcomponents such as sheaths and rollers were considered "active" subcomponents and as such were excluded from an AMR. However, the applicant has conservatively included wire ropes for an AMR even though they could be considered a moving subcomponent. In general, the active components while not included for an AMR, are subject to routine maintenance, which the staff has determined to be adequate. On the basis of the clarification submitted by the applicant and discussed above, the staff finds this response to NRC Question No. 3.2.13(1) reasonable and adequate. On this basis, this issue is considered resolved.

3.11.3.1.3 Electrical Commodities

The applicant reviewed various Electric Power Research Institute (EPRI) reports, NRC reports (NUREGs), and Sandia National Laboratory aging management guidelines during the development of the AMR for ECs to assist in the identification of potential aging mechanisms. Components of ECs consist of metallic and nonmetallic subcomponents and are subject to degradation mechanisms, which depend on the material of construction and the operating environment as discussed below.

For the electrical commodities discussed below, the applicable ARDMs are based on the material and the operating environment. On the basis of these considerations and past experience, it can be concluded that ARDMs, other than those discussed below, do not apply to these components.

Battery terminals are made of aluminum, lead, and copper, and are subject to corrosion; the charger and inverter cabinets are constructed from carbon steel and are susceptible to the effects of electrical stressors and wear. The operating environment for battery terminals/charger and inverter cabinets is that of a controlled atmosphere within the auxiliary building.

Breaker cabinets, made of carbon steel, and associated terminal blocks, made of phenolic materials, are susceptible to the effects of electrical stressors, fatigue, and wear. The operating environment for the cabinets is that of a controlled atmosphere within the auxiliary building.

Bus cabinets are made of carbon steel and are susceptible to fatigue and wear; the cabinets' terminal blocks are susceptible to the effects of electrical stressors. The environment for the bus and disconnect cabinets and associated terminal blocks is that of a controlled atmosphere within the auxiliary building.

MCC panels are made of carbon steel and are subject to fatigue, wear, and dynamic loading. MCC panels' terminal blocks are susceptible to the effects of electrical stressors. The environment for the MCC panels and associated terminal blocks is that of a mild controlled atmosphere within the auxiliary and turbine buildings.

Local control station panels are made of carbon steel and are subject to fatigue, wear, and general corrosion. Local control station panels' terminal blocks are susceptible to the effects of electrical stressors. The environment for the local control station panels and associated terminal blocks is that of a mild controlled atmosphere within the auxiliary building. The saltwater air compressor (SWAC) local control stations panels are located in regions with piping containing either borated water or saltwater.

The miscellaneous panels listed in Table 6.2-3 of Appendix A to the LRA are made of carbon steel and are susceptible to fatigue and wear; the miscellaneous panels' terminal blocks are susceptible to the effects of electrical stressors. The environment for the miscellaneous panels and associated terminal blocks is that of a mild controlled atmosphere within the CCNPP buildings.

Nonmetallic subcomponents in electrical cabinets and panels include subcomponents of active devices, conductor insulation, and subcomponents such as insulating standoff supports. Active devices are excluded from the requirements of an AMR. For organic insulation of wiring or buswork, thermal aging is not plausible since the internal operating temperature is below the 60-year-service limiting temperature for the materials used by the applicant. Subcomponents of the housing/cabinet, such as insulating standoff supports, provide structural support for buswork and ungrounded devices in the housing/cabinets. On the basis of past experience, it can be concluded that these subcomponents are not subject to plausible aging if a thermoset or thermoplastic material is used because thermosets or thermoplastic materials do not degrade when exposed to heat, moisture, and high oxygen. These subcomponents are subject to plausible aging if certain elastomers are used, however.

The operating experience information submitted in the application indicates that the ECs have, in general, performed well and have exhibited no age related degradation that impaired their function. However, some ECs have rusted and corroded from exposure to saltwater spray. The legs of traveling screen control panels were corroded and were replaced with stainless steel support legs. Although these panels are not in the scope of license renewal, they are made of materials and exposed to environments similar to those within the scope of license renewal addressed in this SER. The applicant has stated that the cathodic protection system panels for the IS baffle walls experienced corrosion, and have been replaced with new panels made of fiber-reinforced plastic. Cathodic protection system panels are also not in the scope of license renewal, but they are made of materials and exposed to environments similar to those within the scope of license renewal addressed in this SER. Panels located outdoors or subject to a salty or humid atmosphere are subject to external corrosion if panel doors and penetration seals leak.

As stated in Section 3.11.3 of this SER, as a result of its initial review of Section 6.2 of Appendix A to the LRA, the staff issued a number of questions. The staff's evaluation of the applicant's responses to these questions is summarized below.

(1) In NRC Question No. 6.2.1, the staff asked the applicant to discuss whether corrosion allowances were provided in the design of EC and how corrosion is addressed as part of the aging management program. The applicant responded that no corrosion allowances were included in the specification of electrical panels and that the aging management of the effects of corrosion is by existing PM programs. On the basis of this response, this issue is closed.

(2) On page 6.2-1 of Appendix A to the LRA, the applicant stated that operating experience relevant to aging was obtained from CCNPP-specific information and experience. In NRC Question No. 6.2.2, the staff asked that the applicant submit a summary discussion of any industry-wide operating experience that the applicant concluded was applicable to aging mechanisms for ECs. The applicant responded that various EPRI reports and Sandia National Laboratory aging management guidelines were consulted during the development of the AMR for ECs to assist in the identification of potential aging mechanisms. On the basis of this response, this issue is closed.

(3) On page 6.2-2 of Appendix A to the LRA, the applicant stated that "EC(s) are usually not subject to extreme conditions or excessive loads; however, some CCNPP EC(s) are subject to corrosive environments." In NRC Question No. 6.2.3, the staff asked that the applicant submit a summary description of how the environmental stressors (vibration, heat, radiation, and humidity) and operational stressors (internal heating from electrical or mechanical loading, physical stresses from mechanical or electrical surges, vibration, and abrasive wearing of parts) that have resulted in age related failures in ECs were explicitly addressed in the aging management program(s). The applicant responded that the plausible aging of electrical panels and the programs credited for managing those effects are addressed in Section 6.2 of Appendix A to the LRA. On the basis of this response, this issue is closed.

(4) In NRC Question No. 6.2.4, the staff asked the applicant to clarify the basis for concluding that the PM program can be relied on to detect electrical stressors, as described on page 6.2-9 of Appendix A to the LRA. The applicant responded that the electrical stress, as defined in this section of the LRA, is caused by the overheating at loose connections and by operating in a low-voltage condition for an extended period of time. The applicant further stated that the PM program can manage electrical stress by including visual inspection for effects of abnormal electrical stress. This issue is closed since the staff agrees that an effective PM program can manage electrical stressors by revealing abnormal stresses upon visual inspection.

(5) In NRC Question No. 6.2.5, the staff asked the applicant to tell whether the PM program includes monitoring and trending and describe the monitoring and trending activities. The applicant responded that the PM program is an inspection program that does not include monitoring and trending. On the basis of this response, this issue is closed.

(6) In NRC Question No. 6.2.6, the staff asked if there were any parts of the ECs that are inaccessible for inspection. The staff asked the applicant to describe what aging management program will be relied upon to maintain the integrity of the inaccessible areas. The applicant responded that all electrical panels and cabinets in the scope of license renewal are accessible for inspection. On the basis of this response, this issue is closed.

3.11.3.2 Aging Management Programs

The staff's evaluation of the applicant's AMPs that are applicable to the component supports (including piping segments that provide support), FHEs and other HLHCs, and ECs focused on the program elements rather than on details of specific plant procedures. To determine if these programs contain the essential elements needed for aging management and whether they are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected,

(4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

In the LRA, the applicant indicated that the analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with the site-controlled corrective action program pursuant to 10 CFR Part 50 (Appendix B), and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is discussed separately in Section 3.1.5 of this staff SER. The staff finds that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls." The other seven elements are discussed separately in each pertinent section of the SER.

3.11.3.2.1 Component Supports (Including Piping Segments That Provide Supports)

As described in Section 3.11.3.1.1 of this SER, the applicant determined that the aging effects from six ARDMs (general corrosion of steel, loading from hydraulic vibration or water hammer, loading from rotating/reciprocating equipment, loading due to thermal expansion, elastomer hardening, and stress corrosion cracking of high-strength bolts) are determined to be "plausible" and should be subject to an AMR. The staff's review findings of Appendix A to the LRA regarding the application of the AMPs to the AMR are summarized below.

3.11.3.2.1.1 Effects of Corrosion

The applicant determined that the effects of corrosion should be managed for license renewal. The LRA stated that all component supports are constructed of structural steel, except for elastomer vibration isolators, which are constructed of carbon steel and natural or synthetic rubber, and ring foundations which are constructed from reinforced concrete. The surfaces of component supports are exposed to humid, moist, or wet environments. The effects of corrosion on the surfaces can be mitigated by minimizing the exposure of carbon steel to the environment and by protecting the surface with paint or other protective coatings. Also, plant housekeeping practices that identify conditions such as degraded paint can be used to mitigate the effects of general corrosion.

Two types of discovery activities for detecting aging effects are conducted or are to be conducted by the applicant: baseline activities and follow-on activities. In general, the as-found conditions during the baseline inspections dictate the level of follow-on aging management needed for the component supports. When the baseline discovery activities (including activities for the 24 inaccessible piping supports outside the containment and snubber supports) are conducted, the applicant relies on the SVP and ASME Section XI ISI programs to identify aging effects caused by corrosion. For those component supports not covered or only partially covered by the SVP or ISI program, the applicant will use the "additional baseline walkdowns" to identify aging effects. For the follow-on discovery activities, the applicant relies on the snubber visual inspection surveillance program, structure and system walkdowns (MN-1-319), the ISI program, PM checklists to inspect for coating degradation, NO-1-200 and NO-1-107 walkdown programs, and ARDI for aging management of corrosion of the surfaces of component supports for license renewal.

The staff's evaluation of the applicant's ARDI program and structure and system walkdown procedure (MN-1-319) is discussed separately in Sections 3.1.3 and 3.1.6 of this SER. As for the ASME Section XI ISI program (ISI program), CCNPP Technical Specifications 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 program plan describes the inspections performed to satisfy these requirements. The component support examinations are performed in accordance with the procedure that fulfills the requirements of Section XI. The results of each inspection are documented in an outage report. The ISI for component supports includes visual examination of prescribed sampling of systems covered by these programs. The visual examination focuses on determination of the general mechanical and structural condition of supports and checking for loose parts, debris, abnormal corrosion products, wear, erosion, corrosion, and loss of integrity of bolted or welded connections. The visual examinations are scheduled so that code class piping supports are inspected on a sampling basis once each interval. The applicant stated that the ISI is adequate to manage the effects of aging for the following reasons: component supports are checked for potential ARDMs (e.g., general corrosion of steel, vibration or thermal expansion cycles); inspections performed have identified aging degradation deficiencies; each support within the ISI program is examined at regular intervals; the program requires expansion of inspection scope if degraded supports are observed; and outage reports provide historical information for the supports. The NRC staff agrees and finds that the program procedure meets the seven elements required to identify aging degradation deficiencies for component supports. The staff finds that the frequency of inspections combined with expansion of inspections if deficiencies are identified provide reasonable assurance that aging degradation deficiency will be detected and that corrective actions can be taken in a timely manner.

The staff finds the combined application of these programs by the applicant generally acceptable for the following reasons: (1) the programs cover all component supports subject to an AMR, (2) coating prevents or mitigates corrosion by minimizing environmental exposure, (3) the parameter monitored is coating degradation, which is a condition directly related to potential loss of materials, (4) the exterior carbon steel surfaces cannot degrade without degradation of paint or coating and, thus, inspecting and confirming that the paint or coating is intact is an effective method to ensure that corrosion on external surfaces has not occurred and the intended function is maintained, (5) effects of corrosion are detectable by visual techniques and inspections are periodic (every outage for walkdown and every 2 to 4 years for PM) and should provide for timely detection of aging effects based on operating experience, (6) acceptance criteria ensure that any coating degradations would be reported and evaluated according to site corrective action procedures, and (7) operating experience shows that these programs are effective.

However, the staff identified a concern in its letter dated September 7, 1998, regarding the applicant's reliance on its SVP for the baseline walkdown (by performing a visual inspection) to detect and document the condition (potential ARDMs such as corrosion, elastomer hardening of component supports for mechanical and electrical equipment). According to the applicant (Section 3.1 of Appendix A to the LRA), the SVP was established on the basis of the SQUG guideline in GIP-2. However, as stated on page 5 of Supplemental Safety Evaluation Report No. 2 (SSER-2) on GIP-2 dated May 22, 1992, the qualification of seismic adequacy of equipment and components (including supports) in older operating nuclear plants does not address the aging effects of equipment. In the letter dated September 7, 1998, the staff raised a concern regarding the use of the SVP for the baseline walkdowns of component supports (NRC Question No. 3.1.3). In its response to NRC Question No. 3.1.3 (BGE letter, November 19, 1998), the applicant contended that it has not credited SQUG GIP for aging management and the SVP techniques were used just as one of the sources for grouping component supports. In a teleconference call with the staff on March 3, 1999, the applicant further clarified that it will not exclude any component supports from AMPs based on the results of the SVP baseline walkdowns. Baseline walkdowns do not exclude any component supports from further follow-on aging management activities. On the basis that the applicant's aging management practice for component supports will not rely upon the results of the SVP baseline walkdowns, the staff determined that this issue was resolved.

3.11.3.2.1.2 Effects of Loading From Hydraulic Vibration or Water Hammer

The applicant determined that the effects of loading from hydraulic vibration or water hammer are plausible and should be managed for license renewal. For piping supports, the LRA addresses effects due to these loadings on spring hangers, constant load supports, sway struts, rod hangers, snubber supports, frames, and stanchions. Effects on support types such as spring hangers, constant load supports, sway struts, and rod hangers are considered plausible because these types of supports have threaded fasteners in the load-bearing path that could be loosened by such loading. For piping supports such as frames and stanchions, the LRA indicates that the effects of these loadings on the piping frames and stanchions inside and outside containment are considered plausible. The aging effects could potentially prevent the piping frames from performing their intended support function.

For support types of frames, saddles for tanks and heat exchangers, and LOCA restraints, the applicant determined that the effects of loading caused by hydraulic vibration or water hammer are plausible if such equipment is subject to hydraulic vibration or water hammer. The aging effects from this ARDM are loosening of bolted connections, loss of weld integrity, and component displacement or misalignment. If this aging mechanism is left unmanaged, the effects could progress to the point of insufficient support afforded to the component and/or allowing excessive movement of the equipment or component.

The applicant proposed to use the ISI program, the SVP program, and the "Additional Baseline Walkdowns" program for the baseline walkdowns. For the follow-on discovery activities, the applicant proposed to rely on the "Snubber Visual Inspection Surveillance" program, MN-1-319, NO-1-200, NO-1-107, the ISI program, and the PM program. The staff finds the programs proposed by the applicant for managing the aging effects from hydraulic vibration or water hammer acceptable because (1) these programs cover all component supports subject to AMR; (2) for piping supports such as steel frames and stanchions, these loads were included in the design of the affected supports to prevent the occurrence of the ARDMs; (3) the parameters monitored are loosening of bolted connections, loss of weld integrity, and component displacement or misalignment, which are conditions directly related to potential loss of support integrity; (4) inspecting and confirming that the bolts used for connections are intact, welds are intact, and components are in the proper position are effective methods to ensure that the degradation from hydraulic vibration or water hammer has not occurred and the intended function is maintained; (5) aging effects of loading from hydraulic vibration or water hammer are detectable by visual techniques, and inspections are done periodically and should provide for timely detection of aging effects based on operating experience; (6) acceptance criteria ensure that any connection degradations resulting in component displacements would be reported and evaluated according to site corrective action procedures; and (7) operating experience shows that these programs are effective.

3.11.3.2.1.3 Aging Effects Due From Elastomer Hardening

The applicant determined that the effects of hardening of elastomer materials are plausible and should be managed for license renewal. Elastomer materials (such as natural and synthetic rubber products) are used in the anchorage load path of some rotating equipment to reduce the vibration transmitted to the supporting structures. Extended exposure of elastomer materials to light, heat, oxygen, ozone, water, or radiation can cause this kind of material to become more brittle and promote surface cracking, which may lead to failure of supports. For equipment supports, the LRA addresses the aging effects on elastomer hardening for the elastomer vibration isolators of equipment such as fans and compressors. If this aging mechanism is not properly managed, it could eventually 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.

The applicant proposed to use the SVP inspections for the baseline activities and to document the conditions of component supports. (The staff's conclusion regarding the applicability of the SVP to the baseline inspection is discussed in Section 3.11.3.2.1.1 of this SER.) For the follow-on activities, the applicant relies on walkdowns by system engineers (MN-1-319), the control of shift program (NO-1-200), the ownership of plant operating spaces program (NO-1-107), and the plant modification program. The staff finds the programs proposed by the applicant for managing the aging effects from elastomer hardening acceptable because (1) these programs cover all component supports with elastomer vibration isolators subject to an AMR; (2) the parameter monitored is surface cracking, which is the condition directly related to potential loss of support integrity; (3) as a result of the elastomer hardening (surface cracks), the procedure of visual inspection under AMPs such as MN-1-319 can be relied on to detect the external condition of vibration isolators before a loss of the component support's intended function; (4) aging effects of elastomer hardening are detectable by visual techniques, and inspections are periodic and should provide for timely detection of aging effects on the basis of operating experience; (5) acceptance criteria ensure that any connection degradations resulting in component displacements would be reported and evaluated according to site corrective action procedures; and (6) operating experience shows that these programs are effective.

3.11.3.2.1.4 Effects of Loading From Rotating/Reciprocating Equipment

The applicant determined that effect of loading from rotating/reciprocating equipment is plausible and should be managed for license renewal. For rotating/reciprocating equipment outside the containment building, such as pumps and fans, the LRA addresses age related effects (degradation) from this type of loadings on metal spring isolators and fixed bases. In addition, the LRA covers the age related degradation of LOCA restraints for the reactor coolant pumps (inside containment building) from the same type of loadings.

According to the applicant, all metal spring isolators, fixed bases, and LOCA restraints are constructed of structural steel. The effects of loadings from rotating/reciprocating machinery are plausible for equipment supports such as metal spring isolators and fixed bases (outside the containment), and LOCA restraints (inside the containment), because the machinery supported by these types of supports is subject to vibration from rotation and/or reciprocation while in operation. Samples of the mechanism of aging effects include steel load path degradation, concrete pad degradation, and concrete cracking in the vicinity of equipment anchorage. 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 equipment. This failure of the component supports' intended function could, in turn, lead to loss of function of the supported equipment under CLB conditions.

The applicant proposed to use the ASME Section XI ISI program and SVP inspections for the baseline activities and to document the conditions of component supports. (The staff's conclusion regarding the applicability of the SVP to the baseline inspection is discussed in Section 3.11.3.2.1.1 of this SER.) For the follow-on activities, the applicant relied on system engineer walkdowns (MN-1-319), the control of shift program (NO-1-200), and the ownership of plant operating spaces program (NO-1-107) for metal spring isolators and fixed bases component supports, and the ASME Section XI ISI program for LOCA restraints. On the basis of the discussion in Section 3.11.3.2.1.1 of this SER, the staff finds the programs proposed by the applicant for managing the aging effects due to rotating/reciprocating machinery acceptable.

The staff also finds the use of these programs by the applicant acceptable because (1) the referenced programs include metal spring isolators and fixed bases for rotating/reciprocating equipment (such as pumps and fans), where the effects of loading from rotating/reciprocating machinery are load path degradation, concrete pad degradation, concrete cracking in the vicinity of equipment anchorage, and reduction in component strength if allowed to progress unmanaged (fatigue of metal spring isolators is not considered plausible); (2) the effects of loading from rotation/reciprocating machinery for component supports have been minimized through proper support design and through proper system operation; (3) the parameters monitored are the conditions of component supports; (4) the method used to detect the effects of loading from rotating/reciprocation machinery is an ASME Section XI visual inspection of the support and/or surrounding concrete and baseline walkdowns under the SVP; (5) the method used to monitor and trend the effects of rotation/reciprocating machinery on component supports are baseline walkdowns and follow-on activities; and (6) the acceptance criteria are acceptable conditions of component supports.

3.11.3.2.1.5 Effects of Loading From Thermal Expansion of Piping/Component

The applicant determined that the effects of loadings from thermal expansion of piping and components on component supports (such as frame and saddle supports for tanks and heat exchangers inside and outside the containment), and ring foundations for the flat-bottom vertical tanks are plausible and should be managed for license renewal. As described in the LRA, frames and saddles are constructed of structural steel and are located inside the containment buildings and inside other climate-controlled buildings. The ring foundations for flat-bottom vertical tanks are concrete and are located both inside climate-controlled buildings and outdoors.

The effects of loading's from thermal expansion are plausible, 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. The aging effects from 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 component supports' intended function could, in turn, lead to loss of function of the supported equipment under CLB conditions.

The applicant proposed to use the SVP inspections and ASME Section XI ISI for the baseline activities for identifying degradation from loading caused by thermal expansion. In a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), the applicant indicated that the supports for system 036 (auxiliary feedwater system-condensate storage tank 12) and system 37 (demineralized water and condensate storage system—condensate storage tanks 11 and 21) are inspected as part of the ISI program. As for the follow-on activities, the system engineer walkdowns (MN-1-319)), the control of shift program (NO-1-200), and the ownership of plant operating spaces program (NO-1-107) are credited. Also, on the basis of the results of baseline inspections completed according to the existing ISI program requirements, the applicant determined that continuing ASME Section XI ISI into the period of extended operation will serve as an adequate follow-on activity for frames and saddles subject to the program.

Although there are no CCNP programs credited for mitigation of loading from thermal expansion, the staff finds the applicant's use of these AMPs acceptable because (1) the referenced programs include frames and saddles and the ring foundations for flat-bottom vertical tanks; (2) the effects of aging by thermal expansion are loosening of bolted connections, weld crack initiation and growth, and component displacement or misalignment, and cracking of concrete; (3) aging effects are detected by Section XI and SVP visual inspection of external conditions during a baseline walkdown and with follow-on management activities; (4) the method used to monitor and trend the effect of thermal expansion is visual inspection of external conditions; (5) the acceptance criteria are no loosening of bolted connections, weld crack initiation and growth, and component displacement or misalignment. It is noted that operating experience indications do not cite age degradation for frames and saddles. They do include a discovery of radial cracks in some ring foundations; such cracks, however, did not compromise the structural integrity of the ring foundations based on the applicant's evaluation.

3.11.3.2.1.6 Effects of Loading Caused by Stress Corrosion Cracking of High-Strength Bolts

The applicant points out that high-strength bolting with a yield strength greater than 150 ksi installed in some nuclear applications could be subject to stress corrosion cracking in a humid environment. CCNPP has two types of high-strength bolting in anchor bolt applications: A354 in the reactor vessel, pressurizer, and safety injection tank anchor bolts and A490 in steam generator supports. The applicant has excluded the reactor vessel supports and steam generator supports from the component supports commodity evaluation. Therefore, the applicant only considered stress corrosion cracking for pressurizer and safety injection tank support bolting.

EPRI has reported (NP-5769, Table 4-1) that A354 grade BC bolting has failed in nuclear power plants because of stress corrosion cracking. The failed bolting was caused by improper heat treatment or improper material supplied for this specification. The applicant stated that if bolts with improper heat treatment or improper material were installed at CCNPP, the bolts would have failed soon after installation rather than after many years.

The staff does not entirely agree with the applicant's statements on stress corrosion cracking. For stress corrosion cracking to occur, there must be a susceptible material, a cracking environment, and sufficient tensile stress on the bolting. The fact that the bolting has not cracked does not necessarily mean that the bolting is not susceptible to stress corrosion cracking. In a letter dated September 7, 1998, the staff (NRC Question No. 3.1.24) asked for additional information on this subject. Normally, hardness values for the bolting material are used to indicate if the bolting material is susceptible to stress corrosion cracking. The applicant was asked to address if it had made hardness measurements on either installed bolting or warehouse samples. During discussions with the applicant on February 16, 1999 (NRC meeting summary dated March 19, 1999), the applicant stated that hardness measurements had not been made in the past 10 years, but there had not been any failures of the high-strength bolts. If the bolts were to fail, they would have failed some time ago rather than some time in the future.

Additional investigations by the staff revealed that the applicant may have high-strength bolts that exceed the 150-ksi limit cited by industry experience that results in susceptibility to stress corrosion cracking. The ASTM standard cited for the bolts either requires or permits bolts that are above the 150-ksi limit. ASTM A490 requires a minimum of RC 33 hardness where RC 32 is equivalent to 150 ksi tensile strength. ASTM A354 specifies a range of hardness for bolting from RC 22 to 39, depending on the size of the bolt. During follow-on discussions held on February 24, 1999 (NRC meeting summary dated March 19, 1999), the applicant confirmed that there are high-strength bolts at CCNPP that have tensile strengths higher than 150 ksi. The applicant stated that it is using visual inspection during walkdowns to detect failures of this bolting caused by stress corrosion cracking. The staff agrees that bolts that fail because of stress corrosion cracking can be identified during visual inspections. The staff also agrees that if there are bolts that were going to fail because of stress corrosion cracking, they would have failed by now.

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.

The pressurizer support bolting is subject to baseline inspection as part of the ISI program, as previously described under the subsection, "Group 1—AMPs." The safety injection tank support bolting is not within the normal ISI scope. However, the applicant has stated that the safety injection tank support bolting will be included in the baseline program using ISI procedures as previously described in Section 3.11.3.2.1.1 of this SER. The staff agrees that the pressurizer support bolting and the safety injection tank support bolding should be included in the baseline walkdown program.

For follow-on activities, the applicant stated that the pressurizer support bolting inspections will continue into the period of extended operation using the ISI program and that this will serve as an adequate follow-on activity. However, the follow-on activity for the frames and saddles will depend on the results of the baseline walkdowns. The staff finds that the follow-on activities are adequate for both the pressurizer support bolting inspections and the frames and saddles inspections because visual inspection will identify bolting problems.

The staff finds the applicant's use of these programs acceptable because (1) this program covers high-strength bolting, (2) the high-strength bolting may be susceptible to stress corrosion cracking, (3) the bolting is inspected to ensure that it has not failed or cracked by stress corrosion cracking, (4) the aging effect of stress corrosion cracking in bolts results in cracking or loss of bolt head, (5) the method used to monitor and trend the stress corrosion is an ASME Section XI visual inspection, (6) the acceptance criterion is no cracking or failure of bolting, and (7) operating experience shows that only improperly heat-treated bolts have been susceptible to stress corrosion cracking.

On the basis of the foregoing, the staff finds there is reasonable assurance that the effects of aging will be adequately managed so that the frames, saddles, and pressurizer support bolting will be capable of performing their structural support function consistent with the CLB during the period of extended operation.

3.11.3.2.2 Fuel Handling Equipment and Other Heavy Load Handling Cranes

As described in Section 3.11.3.2.3 of this SER, the applicant determined that the aging effects from five ARDMs (general corrosion/oxidation, fatigue, wear, corrosion due to boric acid, and mechanical degradation/distortion) are determined to be "plausible" and should be subject to AMR. On the basis of the combination of component types and ARDM characteristics, the applicant grouped all components (including supports) and the associated potential ARDMs into the following four groups: (1) general corrosion/oxidation for FHE and HLHC carbon steel components (except the RV cooling shroud structural support members); (2) general corrosion/oxidation and corrosion caused by boric acid for the RV cooling shroud structural support members; (3) fatigue for the PC rails; and (4) fatigue, wear, and mechanical degradation/distortion for wire rope and chains. Only wear is plausible for carbon steel chains. The staff's findings regarding Section 3.2 of Appendix A to the LRA regarding the application of AMPs to these AMRs are summarized below.

3.11.3.2.2.1 General Corrosion/Oxidation

The applicant determined that the effects of general corrosion/oxidation for components made of carbon steel should be managed for license renewal. As described in the LRA, the components of the FHE and HLHC systems are fabricated of various grades of steel. Nickel-based alloys and austenitic stainless steel are very resistant to general corrosion/oxidation. Therefore, general corrosion/oxidation is considered as a plausible ARDM only for those components constructed of carbon steel, improved plow steel, and alloy steel. Most of these components are exposed to climate-controlled environments inside the containment building and the auxiliary building. In these two buildings, the maximum design relative humidity is 70 percent and the maximum design ambient air temperature is in the range of 110 °F to 120 °F. Some of the components are located near the spent fuel pool, where condensation in the presence of oxygen could lead to oxidation. Also, some places can harbor pockets of liquids. The components of the IS's semi-gantry crane are subject to the outdoor environment of condensation and saltwater. Therefore, corrosion is considered as a plausible ARDM for all components constructed of carbon steel.

In the LRA, the applicant stated that the exposed metal surfaces of carbon steel structural components are covered by protective coatings that mitigate the effects of corrosion. The discovery programs are used to verify that protective coatings are maintained. Periodic inspection of carbon steel structural FHE and HLHC components for the effects of corrosion (general corrosion/oxidation) are controlled through a combination of existing and modified operations and maintenance programs. As described in Section 3.2 of Appendix A to the LRA, the existing performance evaluation (PE) program (evaluation and associated operating instructions) is used for discovery and management of corrosion effects in the carbon steel parts of the SFHM, RRM, and associated components by performing periodic visual inspections (every 90 days for the checks of the SFHM). The existing load handling procedure (MN-1-104) is credited for discovery and management of corrosion effects in carbon steel parts of FHE and HLHC components (such as cranes, hoists, and wire rope, as well as nondestructive examination (NDE) of hooks for load handling equipment) by performing annual visual inspections. The modified PM tasks (modified to present inspection requirements) are used for discovery and management of corrosion effects in carbon steel parts of the SFCHC, polar crane, ISSGC, and RV head lift ring by performing visual inspections.

The staff finds that the applicant's combined use of these programs (existing and modified) meets the 10 elements. The staff's evaluation of the combined application of these AMPs against the 10 elements is summarized as follows: (1) these programs cover all FHE and HLHC components subject to an AMR; (2) protective coatings prevent or mitigate corrosion by minimizing environmental exposure; (3) the parameters monitored are coating degradation and rust on the unprotected surfaces, which are the conditions directly related to potential loss of materials; (4) the exterior carbon steel surfaces cannot degrade without degradation of coating or rust on the unprotected surface and, thus, inspecting and confirming that the coating and unprotected surface are intact are effective methods to ensure that corrosion on external surfaces has not occurred and the intended function is maintained; (5) effects of corrosion are detectable by visual techniques and inspections are done every outage by walkdowns (in accordance with Procedure MN-1-104) and every 2 to 4 years for PM, and should provide for timely detection of aging effects on the basis of operating experience; (6) acceptance criteria ensure that any coating degradations or rusting of an unprotected surface would be reported and evaluated according to site corrective action procedures; and (7) operating experience shows that these programs are effective. The staff has previously found that the applicant's AMP satisfied the remaining three elements, (8) corrective actions, (9) confirmation processes, and (10) administrative controls in Section 3.1.5 of this SER.

3.11.3.2.2.2 Corrosion Caused by Boric Acid

For the effects of general corrosion of the external surfaces of the carbon and alloy steel from the potential exposure to concentrated boric acid, the applicant cited its BACI program. The staff's review of the BACI program is discussed separately in Section 3.1.4 of this SER. On the basis of the staff's review, the staff concludes that the applicant has demonstrated that the BACI program is an effective aging management program to manage general external surfaces of the carbon and alloy steel components and that the components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.11.3.2.2.3 Fatigue

The applicant determined that the effects of fatigue, mechanical degradation/distortion, and wear should be managed for the FHE and other HLHCs. The applicant has proposed inspections as part of PM to manage fatigue, wear, and mechanical degradation/distortion for these components during the period of extended operation. The applicant indicated that PM programs would detect the effects of fatigue, mechanical degradation/distortion, and wear on the external and internal surfaces of the components.

The staff identified a concern during the onsite meeting on February 18, 1999 (NRC meeting summary dated March 19, 1999), regarding the stress cycles for the PC rails system which includes the rails, cranes, and supporting structures. The applicant stated that the PC is classified as a Type "A" crane, which has an allowable stress range of 40 Ksi. The PC system is constructed of A36 steel, which has an allowable stress range of 21.6 ksi. Since this allowable stress range is lower than 40.0 ksi, the staff asked the applicant to justify that this lower limit will not be exceeded or that the total number of stress cycles will remain within the allowed cycles during service. In its response, the applicant's assessment indicated that the CCNPP Unit 1 PC components had experienced no more than 8460 load cycles from initial installation until 1992. This assessment was based on the assumption that each lift resulted in four stress cycles to the components. Extending the projection to the year 2034, it is estimated that the PC will experience 13,860 load cycles. This is much less than the maximum of 100,000 assumed for the purposes of determining the allowable stress range of 21.6 ksi. Since the crane is not expected to exceed the originally assumed number of loading cycles, the original design remains bounding, and fatigue is not considered plausible. Since the crane loading cycles for Unit 1 could be projected to be the same for the Unit 2 PC, the staff also finds the applicant's assessment of loading cycles for the Unit 2 PC reasonable and acceptable. On this basis, this issue is considered resolved.

Low-cycle fatigue is considered plausible for the PC rails, and fatigue has been identified as a potential ARDM for this item. The applicant stated in Section 3.2 of Appendix A to the LRA that this ARDM, if unmanaged, could result in unstable crack growth under design loads at the flame-cut hole locations. In NRC Question No. 3.2.10, the staff asked the applicant to discuss its plans for mitigating the potential failure at flame-cut holes and the potential fatigue damage in the PC trolley rails and in other FHE and HLHC components where flame cut holes might exist. The applicant responded that periodic inspections of the PC trolley rails will be performed to detect the onset of fatigue-related damage and the effectiveness of corrective actions will be controlled through an existing PM program. Maintenance tasks and plant administrative procedures require that NDE be conducted on PC rails at appropriate intervals. These tasks also direct visual inspection of the PC rails, and subsequent NDE examination if there is any evidence of cracking. Currently, inspection of the PC rails is performed on a 4-6-year interval. Results are evaluated against earlier inspection records to verify the adequacy of weld repairs, identify trends, and determine the need for future inspections. The corrective action program delineates the necessary corrective actions. Since no further FHE and HLHC components at

CCNPP have flame-cut holes, fatigue damage is limited to the PC trolley rails. On the basis of its review as discussed above, the staff finds the inspection programs to manage fatigue, wear, and mechanical degradation/distortion for the FHE and HLHC components reasonable and acceptable.

3.11.3.2.2.4 Fatigue, Wear, and Mechanical Degradation/Distortion for Wire Rope and Chains

The applicant determined that fatigue, wear, and mechanical degradation/distortion are plausible ARDMs for wire ropes and chains in the FHE and other HLHCs. All potential ARDMs are listed in Table 3.2-1 of Appendix A to the LRA. The applicant has identified no new programs to manage or mitigate the effects of this ARDM for the wire ropes and chains, but has elected to rely on the existing inspection and maintenance programs to manage these ARDMs during the extended period of operation. In addition, the applicant has discussed the specific aspects of the inspection and maintenance programs which, according to the applicant, demonstrate that these ARDMs will be adequately managed during the period of extended operation.

The applicant's scope of the inspection and maintenance programs covers all wire ropes in the FHE and HLHCs. These include fuel upending machines and transfer carriages, refueling machines, main and auxiliary hoists, spent fuel handling machines, fuel elevators, machines in the fuel transfer system, containment PCs, and IS gantry cranes. The staff finds the scope of the inspection and maintenance programs related to the wire ropes and chains reasonable and acceptable.

Fatigue damage in wire ropes results in cracking and breakage of the individual wires and strands that make up 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 high-frequency cycles. Only wear is plausible for carbon steel chains. Fatigue wear and mechanical degradation/distortion were not considered plausible for some components, such as drums and sheaves. In NRC Question No. 3.2.8, the staff asked the applicant to justify excluding sheaves and drums from the AMR. The applicant responded that the scoping process determined that some structural devices, such as drums and sheaves, performed their intended functions while in motion. Such devices were considered to be active subcomponents and were, therefore, not subject to an AMR. The staff concurs with this assessment.

In NRC Question No. 3.2.9, the staff asked the applicant to indicate why fatigue, wear, and mechanical degradation/distortion are not considered plausible ARDMs for the clips, bolts, and stops in the SFCHC, PC, and ISSGC subcomponents even though these subcomponents are subject to accidental loadings during normal operations. The applicant responded that fatigue was not considered a plausible aging mechanism for the carbon steel clips, bolts, and stops for a number of reasons. Thermal fatigue was not feasible since the temperature in these components was not expected to exceed 120 °F. The carbon steel components of the FHE and

HLHC with the exception of the PC rails, are designed so that their operational stresses are well below the yield stress.

The service level for the spent fuel cask handling, the IS semi-gantry, the transfer machine jib, and the PC cranes are designated as Service Level "A" by the Crane Manufacturers Association of America. This designation implies that these cranes do not frequently lift the rated load and the load cycles are less than 100,000. Typically, all of these cranes lift heavy loads only occasionally. Service Level "A" allows a stress range up to 40 ksi. All of the crane components, with the exception of the PC carbon steel rails, will satisfy that criterion. In addition, the fixed structural components of the FHE and HLHC are not expected to experience any wear or fretting from a corrosive environment. The staff agrees with this statement since wear or fretting requires relative motion between structural components.

The staff reviewed the CCNPP PM program (MN-1-102) described in Appendix A to the LRA to determine if the AMPs for the wire ropes would mitigate and prevent the aging degradation during the extended period of operation. In accordance with the operating manual and performance evaluation program discussed in the LRA, 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 more than 60 days and if a refueling outage is imminent. Rope for the spent fuel handling machines, reactor refueling machines, and the spent fuel and new fuel elevators is inspected before refueling outages. The wire ropes for the SFHM and the elevators are also inspected every 90 days. Visual inspections ensure that gross damage from kinking, crushing, unstranding, birdcaging, or broken wires is detected before the load-carrying capability of the wire ropes is lost. Continued use or replacement of damaged wire rope is determined by a person qualified as a load handling engineer in accordance with the requirements established by the American National Standards Institute (ANSI). The effects of wear on the carbon steel chains can also be detected by visual inspection. The applicant's PM program has a number of PM tasks that are implemented in accordance with the administrative procedures and program controls. The NRC has evaluated the PM program as part of its routine licensee assessment activities. The plant maintenance and corrective action program has numerous levels of AMPs and is upgraded to ensure that the inspection frequencies are appropriate for timely detection of the aging effects on the wire ropes and chains. The applicant's plant operating experience indicates that the wire ropes and chains in the FHE and HLHC have not exhibited major signs of age related degradation and the existing PM and corrective action programs have been found adequate.

On the basis of its review, as discussed above, the staff finds that the applicant's existing and modified AMPs for the wire ropes and chains in the FHE and HLHC 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.

3.11.3.2.3 Electrical Commodities

3.11.3.2.3.1 Effects of Fatigue

The applicant determined that the effects of fatigue should be managed for license renewal. The application addresses fatigue on breaker cabinets, bus cabinets, disconnect cabinets, MCC panels, local control station panels, and miscellaneous panels.

Alternating stresses caused by thermal or mechanical cycling of components result in accumulated fatigue usage and can lead to structural damage. Failures may occur at low or high frequencies as a result of cycles of mechanical, thermal, or pressure loads. Fatigue failures occur when the endurance limit number of cycles for a given load amplitude is exceeded.

Fatigue may occur in cabinets and panels because of low-level vibrational loading of electrical equipment such as relays, contactors, and transformers, caused by AC hum or from mechanical operation, which can cause housing welds to crack. The applicant stated that the effect of this ARDM is detectable by visual inspections, but there are no feasible means of preventing fatigue from occurring. The applicant also stated that inclusion of the EC panels, cabinets, and associated terminal blocks in a regular maintenance and overhaul program would provide for the detection of these ARDMs.

The applicant has stated that there are no CCNPP programs that can be credited with the mitigation of fatigue of EC cabinets, panels, and the associated terminal blocks. The repetitive task credited for managing fatigue of a panel will be associated with an appropriate checklist. The applicant performs any required corrective action in accordance with the CCNPP corrective action program.

The staff finds the applicant's proposed programs acceptable because (1) these programs cover the ECs subject to fatigue; (2) effects of fatigue are detectable by visual techniques and inspections are done periodically (every 48 weeks) and should provide for timely detection of fatigue effects; (3) acceptance criteria ensure that any fatigue degradation would be reported and evaluated according to the site corrective action procedures, and (4) operating experience shows that these programs are effective.

3.11.3.2.3.2 Effects of Electrical Stressors

The applicant determined that the effects of electrical stressors should be managed for license renewal. The application addresses electrical stressors' effects on charger cabinets, breaker cabinets, disconnect cabinets, MCC panels, local control station panels, and miscellaneous panels.

Electrical stressors are caused by improper or loose terminations resulting in degradation of organic material and terminal block material. Loose connections or terminations can occur as a result of panel and cabinet operations or vibrations of ECs. Organic materials in EC components may lose mechanical integrity due to cracking and embrittlement causing loss of support and insulation capabilities.

For managing the effects of electrical stressors, the applicant has stated that there are no feasible ways to prevent electrical stressors on the terminal blocks of EC listed above. However, the CCNPP administrative procedure MN-1-102, "Preventive Maintenance Program," can be credited for the discovery of electrical stressors. The applicant utilized industry experience to develop and enhance this program. The PM program can manage electrical stress by including visual inspection for the effects of abnormal electrical stress. This includes specifically looking for signs of overheating (such as cracking or locally discolored spots) of terminal blocks, insulation, or insulators. The applicant performs any required corrective action in accordance with the CCNPP corrective action program to ensure that the affected components remain capable of performing their intended functions under all CLB conditions.

The staff finds the proposed programs acceptable because (1) these programs cover the ECs subject to electrical stressors; (2) repetitive tasks are performed to clean, inspect, and calibrate the susceptible cabinets and panels; (3) the applicant has stated that the repetitive tasks will be modified to include electrical stressors where they are not presently included; (4) acceptance criteria ensure that any degradation due to electrical stressors would be reported and evaluated according to the site corrective action procedures; and (5) operating experience shows that these programs are effective.

3.11.3.2.3.3 Effects of Wear

The applicant determined that the effects of wear are plausible and should be managed for license renewal. The application addresses wear effects on charger cabinets, breaker cabinets, disconnect cabinets, MCC panels, local control station panels, and miscellaneous panels.

Relative motion between two surfaces and sliding motions in a corrosive environment result in degradation caused by wear. Cabinet and panel door hinges, racking mechanisms, and other sliding parts can degrade because of repeatedly opening doors for operational maintenance and testing.

The applicant has stated that there are no feasible methods to prevent wear on the cabinet and panel components. However, the CCNPP administrative procedure MN-1-102, "Preventive Maintenance Program," can be credited for the discovery of wear. The PM program includes periodic inspection of components through maintenance activities. These activities are effective in discovering and managing the age related degradation effects of wear. The applicant performs any required corrective action in accordance with the CCNPP corrective action program to ensure that the affected components remain capable of performing their intended functions under all CLB conditions.

The staff finds the proposed programs acceptable because (1) these programs cover the ECs subject to wear; (2) repetitive tasks are performed to clean, inspect, and calibrate the susceptible cabinets and panels; (3) the applicant has stated that the repetitive tasks will be modified to include wear where it is not presently included; (4) acceptance criteria ensure that any degradation caused by wear will be reported and evaluated according to the site corrective action procedures; and (5) operating experience shows that these programs are effective.

3.11.3.2.3.4 Effects of General Corrosion

The applicant determined that the effects of general corrosion are plausible for battery terminals, boric acid pump control panels, and boric acid pump and SW air compressors' local control station panels, and therefore, should be managed for license renewal.

General corrosion is the wastage of a metal from electrochemical reaction caused by an oxygenated medium with the EC component, which could lead to a loss of seismic integrity of safety-related components and electrical continuity under CLB design conditions. Borated water leaking from piping, valves, and storage tanks can fall on other steel components causing corrosive damage. Acid leakage from station batteries can also cause corrosion of battery terminals. There are no feasible means of preventing general corrosion of battery terminals other than proper maintenance.

The CCNPP administrative procedure MN-1-102, "Preventive Maintenance Program," is credited for the discovery of general corrosion. The PM program requires periodic inspection of components through maintenance activities. These activities are an effective method to discover and manage the age related degradation effects from general corrosion. The applicant performs any required corrective action in accordance with the CCNPP corrective action program to ensure that the affected components remain capable of performing their intended functions under all CLB conditions.

The staff finds the proposed programs acceptable because (1) this program covers general corrosion of battery terminals, boric acid pump control panels, and local control station panels; (2) there are no programs credited for mitigating this aging mechanism; (3) effects of general corrosion are detectable by visual techniques and inspections are done periodically and should provide for timely detection of general corrosion effects; (4) aging management of the effects of corrosion for boric acid pump and saltwater air-compressor local stations is provided by the applicant by means of repetitive task maintenance; (5) aging management of the effects of corrosion for battery racks is provided by the existing PM program; (6) acceptance criteria ensure that any general corrosion degradation would be reported and evaluated according to the site's corrective action procedures; and (7) operating experience shows that these programs are effective.

3.11.4 Conclusions

The staff has reviewed the information in Appendix A, "Technical Information," to the LRA, which comprises Section 3.1, "Component Supports"; Section 3.1A, "Piping Segments That Provide Structural Support"; Section 3.2, "Fuel Handling Equipment and Other Heavy Load Handling Cranes"; and Revision 1 of Section 6.2, "Electrical Commodities" as well as additional information sent by the applicant in response to the staff's RAIs. The staff concludes that the applicant has demonstrated that the aging effects associated with the component supports (including piping segments that provide structural support), FHE and HLHC systems, and electrical commodities will be adequately managed so that there is reasonable assurance that component supports, FHE and HLHC systems, and electrical commodities will perform their intended functions in accordance with the CLB during the period of extended operation.

3.12 Electrical Components

3.12.1 Introduction

The applicant described its AMR of electrical components for license renewal in Section 6.1, "Cables," of Appendix A to the LRA. The staff reviewed this section of the application to determine if there is reasonable assurance that the applicant presented adequate information to conform to the requirements stated in 10 CFR 54.21(a)(3) for managing aging effects of cables for license renewal.

3.12.2 Summary of Technical Information in the Application

3.12.2.1 Structures and Components Subject to an Aging Management Review

Section 6.1 of Appendix A to the LRA describes cables as a "commodity" in accordance with the applicant's IPA methodology described in Section 2.0 of Appendix A to the LRA. Cables support various plant electrical components, which are required to perform the functions described in 10 CFR 54.4(a)(1),(2), and (3). Cable serves as the electrical path between electrical components in order to provide ac or dc power required for component operation, voltage or current signals for component control functions, and voltage and current signals for instrumentation signals. The applicant grouped cable types ARDM combinations where there are similar characteristics applicable to all cables within that group. The following groups have been selected:

Group 1—Includes thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing. The highest (non-accident) ambient design temperature of any area in the plant that maintains cabling is in the main steam penetration room. This room has a maximum design ambient temperature of 71°C. The Group 1 cables are also subject to ohmic heating, which can expose the cables to a temperature environment hotter than the ambient temperature. By letter dated September 17, 1998, the applicant stated that the ARDI is complete and based on analysis of data collected from the thermally bounding locations for Group 1, no Group 1 cables are subject to plausible aging (thermal aging) and the peak recorded temperature for these cables (79°C) was well below the cable insulation thermal limit of 90°C.

Group 2—Includes thermal aging for EPR/XLPE non-EQ cables in power service, which are routed with maintained spacing. The highest (non-accident) ambient design temperature of any area in the plant that contains cabling is in the main steam penetration room. This room has a maximum design ambient temperature of 51°C. The Group 2 cables are also subject to ohmic heating effects, which can expose the cables to a temperature environment hotter than the ambient temperature.

Group 3—Includes synergistic radiative and thermal aging for EPR/XLPE non-EQ cables in power service, which are routed inside the containment. The maximum normal ambient temperature in the containment is 49°C. The normal general radiation background level is 1 rad/hr (although it may be higher in some locations). The power cables may also be subject to ohmic heating and localized heating effects, which can expose the cables to a temperature environment hotter than the ambient temperature.

Group 4—Includes thermal aging for ethylene propylene rubber (EPR) non-EQ cables in power service, associated with the saltwater system and service water system 4-kV-pump motor terminations. The power cable for each of the pump motors is routed from the power source, via conduits and trays, to a junction box on the pump motor, which contains the motor leads. The power cable is bolt spliced to the motor leads in this junction box. The bolted splice is wrapped with insulating tape. These cables are located in the IS pump room and in the service water pump room. The cables in these areas are subjected to localized heating effects from their close proximity to the pump motors. The normal maximum temperatures are 40 °C in the IS pump room and 45 °C in the service water pump room.

Group 5—Includes insulation resistance reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable insulation resistence. The cable is used in the RMS, power-range nuclear instrumentation, and wide-range nuclear instrumentation circuits routed throughout the plant (inside and outside of the containment). The highest (non-accident) ambient design temperature of any area in the plant that contains cabling is in the main steam penetration room which has a maximum design ambient temperature of 71 °C. The normal general background radiation level inside the containment is 1 rad/hr (although it may be higher in some locations). There are no design radiation requirements outside the containment during normal operating conditions.

Group 6—Includes "treeing" for EPR non-EQ cables in 4-kV-power service. Treeing is a form of voltage-induced degradation that causes hollow microchannels in the cable insulation to grow in a tree-like pattern. These cables with EPR insulation are associated with the saltwater pumps, the service water pumps, and the safety-related 4-kV feeds from the 4-kV unit buses to the 480-V unit buses. These cables are subjected to 4-kV service voltage, continuously energized, and the insulation is subject to an electrical stress of 35 V/mil or more. Initially, this limit was set at 35V/mil, but has since been updated to 100V/mil. No cables were found to be subject to plausible treeing at CCNPP when the new criterion of 100V/mil is applied.

The applicant identified the following passive intended functions for cables depending on their service:

- Maintenance of dielectric strength—(applies to most power and control cables)
- Maintenance of adequate insulation resistence (for non-coax) or impedance (for coax)—(applies to some instrumentation cables).

3.12.2.2 Effects of Aging

The applicant evaluated the applicability of ARDMs for the cables subject to an AMR. The applicant determined that the aging effects from the following "plausible" ARDMs should be managed for license renewal: treeing, thermal aging, synergistic thermal and radiative aging, and insulation resistence reduction (insulation resistence reduction is actually an aging effect rather than an ARDM). The LRA also contains information on the historical operating experience, which gives insight in supporting the aging management demonstrations provided in Section 6.1 of Appendix A to the LRA.

3.12.2.3 Aging Management Programs

The applicant identified the following AMPs for cables for license renewal in the application:

- Instrument Calibration Program, MN-1-211—Management of the effects of insulation resistence reduction for Group 5 (EPR/XLPE/XLPO non-EQ cables in instrumentation service, sensitive to reduction in cable insulation resistence).

- Electrical Preventive Maintenance (EPM) Program (EPM Checklists EPM04000/04003/05135)— Management of the effects of thermal aging for Group 4 (EPR non-EQ cables in power service, associated with saltwater system and service water system 4-kV pump motor terminations).

- Cable replacement program for Group 2 and 3 cables.

- Replacement of wiring in 480 Vac motor control center unless a different AMP is developed.

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended functions of the cables would be maintained during the period of extended operation, consistent with the CLB.

3.12.2.4 Time-Limited Aging Analysis

The staff's evaluation of the applicant's identification of TLAAs is discussed separately in Chapter 4 of this SER.

3.12.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Section 6.1 of Appendix A to the LRA regarding the applicant's demonstration that effects of aging will be adequately managed so that the intended functions of the cables will be maintained consistent with the CLB for the period of extended operation. Initially, the staff reviewed the potential and plausible ARDMs for the six cable groups identified by the applicant and concluded that additional information was required in several areas. After completing the initial review, by letter dated July 9, 1998, the staff issued a request for additional information (RAI). By letter dated September 17, 1998, the applicant responded to the staff's RAIs.

The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER.

3.12.3.1 Effects of Aging

The cable insulation material types include silicone rubber, ethylene propylene rubber (EPR), crosslinked polyethylene (XLPE), crosslinked polyolefin (XLPO), mineral, Kapton, polyvinyl chloride, Teflon, and other miscellaneous insulation types. The external environment is air. The applicant identified the applicable ARDMs as thermal aging, synergistic thermal and radiative aging, and insulation resistence reduction. Although the license renewal rule requires management of aging effects and does not require specific identification of ARDMs, the applicant elected to evaluate specific ARDMs. The applicant considered a comprehensive list of potential ARDMs in its evaluation. The staff finds this acceptable because the potential ARDMs of thermal/radiative aging, and insulation resistence reduction are considered to be plausible for cables. Accordingly, the staff finds the applicant's approach of identifying ARDMs acceptable because aging effects are results of ARDMs.

The operating experience information in the application indicates that the number of cable failures during normal operating conditions (all voltage classes) that have occurred throughout the industry have been extremely low. However, thermal aging resulting in embrittlement of insulation is one of the most significant aging mechanisms for low-voltage cable during normal operating conditions.

The applicant determined that the effects of thermal aging, synergistic thermal and radiative aging, and insulation resistence reduction should be managed for license renewal. The staff agrees with the plausible ARDMs identified by the applicant. The staff agrees that the aging of

Kapton, treeing, electrical stress, and mechanical stress and installation damage are not considered to be plausible.

3.12.3.2 Aging Management Programs

The staff's evaluation of the applicant's AMPs was focused on the program elements rather than on the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that the analysis/assessment, corrective action, and confirmation/ documentation process for license renewal is in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50 (Appendix B), and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective actions program is provided separately in Section 3.1.5 of this SER. In that portion of this SER, the staff concluded that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

The other program elements are evaluated in other sections of the SERs as noted below.

3.12.3.2.1 Effects of Thermal Aging

Group 2 and 4 cables may be subject to thermal stress resulting from ambient, ohmic, and localized heating effects. Elevated temperature produces some degree of aging in most organic materials. Thermal aging of the cables' organic outer jacket or insulation can produce changes in the organic material properties, including reduced elongation, variations in tensile strength, loss of antioxidant, and loss of plasticizer. Visual indications of thermal aging may include embrittlement, cracking, discoloration, and melting of the jacket and insulation. The potential effects on the jacket and insulation include reduced mechanical integrity and protection from the environment and reduced insulation resistence, increased noise, changes in flammability, and electrical failure.

To manage the effects of thermal aging for Group 2 cables, they will be replaced before the extended period of operation if they are found to have plausible aging. Thermal aging for Group 4 cables will be managed by the plant's PM program. EPMs 04000, 04003, and 05135 will be modified to inspect for evidence of this mechanism. The EPM program is acceptable for managing the effects of aging because the program provides for visual inspection in Group 4 and the scope of the program has been modified to specifically include cable terminations, and visual inspection provides sufficient indications of the need for preventive actions by inspecting the cable termination jacket and insulation (the key parameter) for thermal degradation (acceptance criteria). In the initial LRA submittal, the applicant had stated that Group 1 cables were subject to thermal aging. However, by letter dated September 17, 1998, the applicant stated that as a result of conducting an ARDI of the Group 1 cables, the cables are not subject to thermal aging because the service temperatures that these cables are subjected to are below the cable insulation rated temperature. The staff agrees with this conclusion because the peak recorded temperature by the ARDI of the Group 1 cables was 79°C, which was well below the thermal limit for the cable insulation of 90°C.

In addition, earlier operating experience has been adequately factored into the program. The number of cable failures during normal operating conditions (all voltage classes) that have occurred throughout the industry is low in proportion to the amount of cables that are in service.

3.12.3.2.2 Effects of Synergistic Thermal and Radiative Aging

Group 3 cables may be subjected to synergistic radiative and thermal aging when both aging mechanisms are active and at least one may be significant. Radiation-induced and thermal-induced degradation in organic materials (cable jacket and insulation) produces changes in the organic material properties, including reduced elongation and changes in tensile strength. Visible indications of radiative/thermal aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. To manage the aging effects on Group 3 cables, they will be replaced before the extended period of operation if they are found to have plausible aging.

3.12.3.2.3 Effects of Insulation Resistance Reduction

The Group 5 cables may be subject to thermal stress due to ambient heating effects, and inside containment these cables are also subject to radiation stress. Both the thermal and radiation-induced degradation of the cable insulation can result in reduced insulation resistence. The reduction in insulation resistence causes an increase in leakage currents between conductors, and from individual conductors to ground. The insulation resistence reduction can be a concern for circuits with sensitive, low-level signals such as current transmitters, resistance temperature detectors, and thermocouples. To manage the insulation resistence reduction effects on the Group 5 cables, the existing instrument calibration program, MN-1-211, will be used to provide performance monitoring of the affected circuits. The instrument calibration program is acceptable for managing the effects of aging because the scope of the program includes all instrumentation, and calibration provides sufficient indication of the need for preventive actions by monitoring key parameters and providing trending data based on acceptance criteria related to instrument performance. In addition, operating experience has been adequately factored into the program. The number of cable failures based on trending data during normal operation is low in proportion to the amount of cables used throughout the industry.

In addition, internal operating temperatures in 480-V AC MCCs can approach 60-year service limits for Group 5 polyolefin insulated wiring. Therefore, thermal aging is plausible for polyolefin insulated wiring in 480-V AC MCCs and will require aging management. The applicant will replace wiring in the 480-V AC MCCs.

3.12.3.2.4 Cables ARDI Program

The purpose of the cables' ARDI program is to determine if plausible aging could potentially progress to cable failure so that ongoing aging management is required to be implemented. If the results of the ARDI program show that the acceptance criteria are not met so that service limiting temperature or radiation values are exceeded for Group 1, 2, and 3 cables or if treeing is detected for Group 6 cables, appropriate corrective action (ongoing aging management) will be taken and may consist of the following:

- Rerouting cable so that the service limiting temperature/radiation values will not be exceeded;
- Analysis to determine a cable replacement date;
- Visual or physical inspection for embrittlement, cracking discoloration, and melting;
- Pulling cable samples for testing of chemical, mechanical, or electrical properties;
- In-situ non-destructive testing, that is, condition monitoring; and
- Replacement of cable because of treeing or thermal/radiation damage

The cables' ARDI program is acceptable for managing the effects of aging for Group 1, 2, 3, and 6 cables because (1) the scope includes all non-EQ cables in power and control service routed with maintained spacing, without maintained spacing, inside containment, and in 4-kV power service; (2) visual or physical inspection (for cable flexibility) and thermal surveys provide sufficient indication of the need for preventive actions by monitoring key parameters; and (3) analysis, including trending data based on acceptance criteria related to cable performance, is included. In addition, operating experience has been adequately factored into the cables' ARDI program. The number of cable failures during normal operating conditions that have occurred in the industry is low in proportion to the amount of cables that are in service.

In the LRA, the applicant indicated that the electrical cable ARDI was in progress. The ARDI is now complete and the following results were presented in the September 17, 1998, BGE letter for cable groups 1, 2, 3 and 6:

- On the basis of analysis of data collected from the thermally bounding locations for Group 1, no Group 1 cables are subject to plausible aging.

- Some of the Group 2 cables were found to be subject to plausible thermal aging during 60 years of plant service. However, none of the calculated maximum service temperatures were found to exceed the 60°C (194°F) limit.

- Group 3 cables inside containment, insulated with EPR or XLPE, in the scope of license renewal, and not environmentally qualified, were concluded to be subject to plausible synergistic radiative and thermal aging and will need to be replaced before the period of extended operation. Therefore, the applicant has committed to perform a one-time replacement of these cables.

- No Group 6 cables in the scope of license renewal, continuously energized, and subject to an electrical stress of at least 100 V/mil, were found to be subject to plausible treeing.

The staff considers the results of the ARDIs to be adequate and acceptable.

3.12.3.3 Time-Limited Aging Analysis

The staff's evaluation of the applicant's identification of TLAAs is discussed separately in Chapter 4 of this SER.

3.12.4 Conclusions

The staff has reviewed the information presented in Section 6.1, "Cables," of Appendix A to the LRA and additional information sent by the applicant in response to the staff's RAIs. On the basis of this review as stated above, the staff concludes that the applicant has provided an acceptable demonstration that the aging effects associated with the cables will be adequately managed so that there is reasonable assurance the cables will perform their intended functions in accordance with the CLB during the period of extended operation.

3.13 Environmentally Qualified Equipment

3.13.1 Introduction

The applicant described its AMR of environmentally qualified (EQ) equipment for license renewal in Section 6.3, "Environmentally Qualified Equipment," of Appendix A to the LRA. The staff reviewed this section of the application to determine whether the applicant submitted adequate information to meet the requirements stated in 10 CFR 54.4(a)(3) for managing aging effects of EQ equipment for license renewal, as is described in Section 2.2.3.34 of this SER.

3.13.2 Summary of Technical Information in the Application

3.13.2.1 Structures and Components Subject to an Aging Management Review

In Section 6.3 of Appendix A to the LRA, which addresses the EQ provision (10 CFR 50.49) of 10 CFR 54.4(a)(3) and 10 CFR 54.21(a)(1), the applicant has identified the following eight EQ devices with qualified lives greater than or equal to 40 years that are subject to an AMR:

- cables (CBL)
- junction box (WRNMS)
- containment penetration assembly (PEN)
- core exit thermocouple system (RI)
- seal (SEAL)
- solenoid valve (SV)
- terminal block
- reactor vessel level monitoring system in-core assembly

The applicant identified the following passive intended functions for EQ device types requiring an AMR:

Device Type	**Passive Intended Function**
CBL	Provide electrical continuity.
WRNMS	Provide electrical continuity.
PEN	Provide electrical continuity. Provide containment pressure boundary.
RI	Provide pressure seal at reactor vessel. Provide electrical continuity.
SEAL	Prevent moisture intrusion into electrical connections.
SV	Maintain system pressure boundary.
terminal block	Provide electrical continuity.
reactor vessel level monitoring system in-core assembly (RVLMS)	Provide pressure seal at reactor vessel. Provide electrical continuity.

3.13.2.2 Effects of Aging

The applicant evaluated the applicability of ARDMs for the preceding eight EQ devices that are subject to an AMR. The applicant determined that the aging effects from the following "plausible" ARDMs should be managed for license renewal: crevice corrosion, general corrosion, Kapton-unique aging, pitting, radiation aging, and thermal aging. The application also contains information on the historical operating experience, which provides insight in supporting the aging management demonstrations presented in Section 6.3 of Appendix A to the LRA.

3.13.2.3 Aging Management Programs

The applicant identified the following AMPs for the eight EQ devices identified above for license renewal in the application:

• General corrosion	MN-1-319, MN-3-100, QL-2-100 programs
• Kapton-unique aging	50.49 EQ program
• Crevice Corrosion & Pitting	Chemistry control program and ARDI
• Radiation aging	50.49 EQ program
• Thermal aging	50.49 EQ program

The applicant concluded that these programs would manage the ARDMs and their effects in such a way that the intended functions of the eight EQ devices identified above would be maintained during the period of extended operation, consistent with the CLB.

3.13.2.4 Time-Limited Aging Analyses

Section 6.3.3, "Environmentally Qualified Equipment," of Appendix A to the LRA discusses the TLAA function of the CCNPP 10 CFR 50.49 program and how it is implemented.

3.13.3 Staff Evaluation

In accordance with 10 CFR 54.4(a)(3), the staff reviewed the information in Section 6.3 of Appendix A to the LRA regarding the applicant's demonstration that the effects of aging will be adequately managed so that the intended functions of the EQ devices will be maintained consistent with the CLB for the period of extended operation. The staff's evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this SER.

Aging Management Review

3.13.3.1 Effects of Aging

For cables, junction boxes, containment penetration assemblies, core exit thermocouple systems, seals, solenoid valves, terminal blocks, and reactor vessel level monitoring system in-core assemblies, the applicant identified the following applicable ARDMs: crevice corrosion, general corrosion, Kapton unique aging, pitting, radiation aging, and thermal aging. Although the license renewal rule requires management of aging effects and does not require identification of ARDMs, the applicant elected to evaluate specific ARDMs. The staff finds the applicant's approach of identifying ARDMs acceptable because aging effects are results of ARDMs. Because the applicant considered a comprehensive list of potential ARDMs in its evaluation, the staff finds this acceptable.

The operating experience information in the application discusses EQ-related issues/problems that have been identified by the NRC and by the applicant and its contractors as a result of audits, assessments, and day-to-day plant operation. EQ-related issues and problems have been documented in nonconformance reports, IRs, and program deficiency reports as part of the applicant's deficiency identification and corrective action program. In each case, the appropriate corrective action was taken as required.

The applicant determined that the effects of crevice corrosion, general corrosion, Kapton-unique aging, pitting, radiation aging , and thermal aging should be managed for license renewal. The staff agrees with the plausible ARDMs identified by the applicant. The staff also agrees that potential ARDMs identified by the applicant such as cavitation erosion, corrosion fatigue, erosion/corrosion, fatigue, fouling, galvanic corrosion, hydrogen attack, intergranular attack, micro-biologically induced corrosion, oxidation, particulate wear erosion, rubber degradation, selective leaching, stress relaxation, thermal embrittlement, and wear are not considered to be plausible.

3.13.3.2 Aging Management Programs

The staff focused its evaluation of the applicant's AMPs on the program elements rather than on details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that the analysis/assessment, corrective action, and confirmation/documentation process for license renewal is in accordance with the site controlled corrective action program pursuant to 10 CFR Part 50 (Appendix B), and covers all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective actions program is discussed separately in Section 3.1.5 of this SER. In that portion of this SER, the staff concluded that the applicant's AMPs for license renewal satisfy the elements of "corrective actions," "confirmation process," and "administrative controls."

The other program elements are evaluated in other sections of this SER as referenced below.

3.13.3.2.1 Effects of Crevice Corrosion

Crevice corrosion has been identified by the applicant as a plausible ARDM for solenoid valves, the reactor vessel level monitoring in-core assembly, and the core exit thermocouple system. To manage the effects of crevice corrosion for solenoid valves, the valves will be subjected to the chemistry control program (wetted valves only). Crevice corrosion is a localized corrosion that occurs in cracks or crevices and is controlled by the chemistry program which mitigates the migration of chlorides and hydroxides in the recesses of a crevice and thus inhibits the corrosion. The effectiveness of chemistry control programs in managing the effects of crevice corrosion and pitting ARDMs is described, for example, for the components in the reactor coolant system, in Section 3.1.2.3 of this SER. As described in that section, the water chemistry program will minimize the potential for these aging effects and, in conjunction with the other applicable routine inspection, testing and maintenance activities applicable to the devices and components within the scope of this review, will provide an adequate program for managing the effects of crevice corrosion. In addition, the effects of crevice corrosion for the solenoid valves will be managed by the ARDI program.

3.13.3.2.2 Effects of General Corrosion

General corrosion has been identified by the applicant as a plausible ARDM for containment penetration assemblies. To manage the effects of aging for containment penetration assemblies, the assemblies will be subjected to the PEG-7, MN-3-100, and QL-2-100 AMPs, which are addressed in Section 3.2.3.2 of this SER.

3.13.3.2.3 Effects of Kapton-Unique Aging

Kapton unique aging has been identified by the applicant as a plausible ARDM for Valcor solenoid valves (Kapton undergoes accelerated aging when under sufficient mechanical stress in a hot and wet environment). To manage the effects of aging for Valcor post-accident-monitoring solenoid valves, they will be subjected to the applicant's 10 CFR 50.49 EQ program which is addressed in Section 4.2 of this SER.

3.13.3.2.4 Effects of Pitting

Pitting has been identified by the applicant as a plausible ARDM for solenoid valves, the reactor vessel level monitoring system in-core assembly, and core exit thermocouple system. To manage the effects of aging for solenoid valves, they will be subjected to the chemistry control program. Pitting or local corrosion that occurs on the surface material of these devices is controlled by the chemistry program, which minimizes the exposure of the metal surfaces to the aggressive chemical environment that can result in wall thinning of ferritic steel components. The effectiveness of the chemistry control program in managing the effects of crevice corrosion and pitting ARDMs is described, for example, for the components in the reactor coolant system, in Section 3.1.2.3 of this SER. As described in that section, the water chemistry program will minimize the potential for these aging effects and, in conjunction with the other applicable routine inspection, testing and maintenance activities applicable to the devices and components within the scope of this review, will provide an adequate program for managing the effects of crevice corrosion. In addition, the effects of pitting for the solenoid valves will be managed by the ARDI program.

3.13.3.2.5 Effects of Thermal and Radiation Damage

Thermal and radiation damage have been identified by the applicant as plausible ARDMs for cables, junction boxes, containment penetration assemblies, core exit thermocouple systems, seals, solenoid valves, terminal blocks, and reactor level vessel monitoring system in-core assemblies. To manage the effects of aging for these EQ devices, they will be subjected to the applicant's 10 CFR 50.49 EQ program, which is addressed in Section 4.2 of this SER.

3.13.3.3 Time-Limited Aging Analyses

The staff's evaluation of the applicant's identification of TLAAs is discussed separately in Chapter 4 of this SER.

3.13.4 Conclusions

The staff has reviewed the information in Section 6.3, "Environmentally Qualified Equipment" of Appendix A to the LRA. On the basis of this review as stated above, the staff concludes that the applicant has provided an acceptable demonstration that the aging effects associated with the EQ devices identified above will be adequately managed so that there is reasonable assurance that these devices will perform their intended functions in accordance with the CLB during the period of extended operation.

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-limited Aging Analyses

The applicant addressed time-limited aging analyses (TLAAs) in Section 2.1 of the license renewal application (LRA). The applicant has provided a list of TLAAs (Table 2.1-1) identified in the current licensing basis and has evaluated each TLAA in accordance with the Calvert Cliffs Nuclear Power Plant (CCNPP) integrated plant assessment (IPA) methodology in Section 2.0 of the applicant's license renewal application (LRA).

4.1.1 Introduction

The staff has reviewed Section 2.1 of the LRA to determine whether the applicant submitted information adequate to satisfy the requirements in 10 CFR 54.21(c)(1).

4.1.2 Summary of Technical Information in the Application

The applicant has identified each TLAA of Table 2.1-1 of Appendix A to the LRA with its aging effect and disposition, to demonstrate that (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. With regard to TLAAs and associated aging effects, the applicant outlined the following:

- The environmental qualification (EQ) program is applicable to all long-lived equipment whether active or passive, relates to a calculation of qualified life of equipment, and is also a demonstration of managing aging effects on the intended function of electrical equipment for the period of extended operation. The EQ TLAA is evaluated in Section 4.2 of this SER.

- Heatup and cooldown (pressure/temperature limits) curves for the reactor coolant system (RCS) relate to the effect of irradiation embrittlement of the reactor pressure vessel. The analyses for pressurized thermal shock (PTS) and low-temperature overpressure protection (LTOP) are also affected by embrittlement concerns.

- The fatigue analyses for the RCS piping, steam generator, pressurizer, pressurizer auxiliary spray line, and pressurizer surge line demonstrate that the effects of fatigue on the intended functions of NSSS components will be adequately managed for the period of extended operation. The NRC staff's concerns regarding Generic Safety Issue (GSI-166), "Adequacy of the Fatigue Life of Metal Components" are addressed in the referenced sections of the LRA.

- The fatigue analysis for the main steam supply lines to the turbine-driven auxiliary feedwater pumps remains valid for the period of extended operation based on a limiting number of thermal cycles.

- The containment liner plate fatigue analysis is a TLAA with a limiting number of thermal cycles during the licensed life of the plant. This analysis will be projected to the end of the period of extended operation by the year 2012.

- The loss of prestress on containment tendons is time-dependent as a result of age-related degradation such as creep and shrinkage of concrete, stress relaxation, corrosion, and anchorage seating losses. The technical specification surveillance test is a measure of a parameter (liftoff force) to ensure that the prestress loss of tendons is within acceptable limits. To account for the period of extended operation, the applicant committed to recalculating, by the year 2012, the curves in the technical specification pertaining to the applicable measurement parameter for the current licensing basis (CLB).

- The criticality analyses for the Unit 1 spent fuel pool are TLAAs due to age-related depletion of boron-10 used as neutron-absorbing material between spent fuel assemblies. The applicant has performed an aging analysis for the poison sheets and has determined that there are plausible aging mechanisms requiring an aging management program for the period of extended operation. This is discussed in Section 3.10.3.2.11 of the SER.

- Pursuant to 10 CFR 54.21(c)(2), the applicant has stated that it found no exemptions granted under 10 CFR 50.12 that were based on a TLAA.

4.1.3 Staff Evaluation

The staff has reviewed the applicant's identification and evaluation of TLAAs in Table 2.1-1 of Appendix A to the LRA and requested additional information pertaining to exclusion of certain potential items concerning TLAAs. The applicant sent a response dated November 4, 1998, to the staff's request for additional information (RAI) and presented a clarification during the on-site meeting held between February 16–18, 1999 (documented in the meeting summary dated March 19, 1999). The staff's findings are summarized below:

The plant heatup/cooldown (pressure/temperature or "P/T" limit) curves are a group of TLAAs that take into consideration the fracture toughness of the most limiting material in the RCS, which is the reactor vessel beltline material. The fracture toughness of the beltline material, however, is affected by neutron fluence, which is time-dependent. These TLAAs concern the aging effect due to irradiation embrittlement. The applicant's current set of heatup/cooldown curves in the technical specifications are valid through the period of extended operation for Unit 1, and the curves for Unit 2 are valid for 30 effective full-power years. The applicant committed to continue updating the technical specifications as further data from surveillance capsules are obtained. The applicant has identified the PTS and the LTOP analyses as TLAAs since they are affected by irradiation embrittlement of the reactor vessel. The PTS analyses for both vessels projected to the end of the license renewal term show that the reference temperature for PTS will be below the screening criteria through the period of extended operation. The LTOP analysis suggests that the effects of aging on low temperature overpressurization protection will be managed though the period of extended operation by providing setpoints for power-operated relief valves and implementing administrative controls. The applicant has provided the projected peak neutron fluence for the period of extended operation in the LRA. The NRC staff determined that revisions to Charpy upper shelf energy (USE) could be performed using the current applicant process to comply with the requirements of 10 CFR Part 50, (Appendices G and H). The applicant committed to perform these calculations by the end of the current license term. This is acceptable because the applicant has already demonstrated compliance with Appendices G and H for the current term and must continue to demonstrate compliance with Appendix G through the period of extended operation.

However, the list of TLAAs provided pursuant to 10 CFR 54.21(c)(1) does not include the USE of the reactor vessel materials, including the most limiting material based on fluence and chemistry of the vessel material. The applicant stated during the on-site meeting held between February 16-18, 1999 (as documented in the meeting summary dated March 19, 1999), that irradiation embrittlement as measured by the drop in Charpy USE is not a TLAA since it does not satisfy the TLAA definition in 10 CFR 54.3. The NRC staff, however, has concluded that this is a TLAA and considered this as Open Item 4.1.3-1. In a letter dated July 2, 1999, the applicant stated that the analyses applicable to neutron irradiation of the reactor vessels had been extended from 40 years to 60 years before the applicant implemented its TLAA identification and evaluation process. The staff had approved the analyses in a safety evaluation dated January 2, 1996. Since the analyses have been projected to the end of the period of extended operation, in accordance with 10 CFR 54.21(c)(1)(ii), the applicant has dispositioned its TLAA relating to Charpy USE. Therefore, Open Item 4.1.3-1 is closed.

The fatigue analyses for the NSSS covering the reactor coolant system (RCS), reactor pressure vessel (RPV), steam generator, pressurizer, pressurizer auxiliary spray, and pressurizer surge line are TLAAs. The applicant's fatigue monitoring program (FMP) relies on evaluation of critical plant transients for selected RPV and RCS components at CCNPP to manage fatigue. The staff agrees that monitoring of plant transients causing significant fatigue usage for critical components can adequately represent the fatigue usage for the remaining RPV and RCS locations. By letter dated July 2, 1999, the applicant has committed to complete the additional evaluations described in Sections 3.2.3.2.2, 3.3.3.2.2, and 3.9.3.2.3 of this SER. Based on this commitment, the staff concludes that the applicant's FMP sampling approach is adequate to manage fatigue of the NSSS components and the SG FW nozzles.

The fatigue analysis for the main steam piping to the turbine-driven auxiliary feedwater pumps is a TLAA. The main steam piping is designed assuming (for purposes of bounding the fatigue analysis) that it will experience 7000 thermal cycles and still perform its intended functions. Because the number of thermal cycles is expected to be well below this limiting assumption, the staff has accepted the applicant's conclusion that 7000 assumed thermal cycles will not be exceeded during the period of extended operation and, therefore, the existing fatigue analyses meet the criteria of 10 CFR 54.21(c)(1)(i).

The containment liner plate fatigue is a TLAA with a limiting number of thermal cycles during the licensed life of the plant. As indicated in a February 16, 1999, meeting (NRC meeting summary dated March 19, 1999), the applicant has presented an evaluation demonstrating that the current analysis remains valid for the period of extended operation. The staff reviewed this information and found it acceptable because it was performed for 60 years. However, the staff concluded that this information should be documented and identified this as Confirmatory Item 4.1.3-1. On April 2, 1999, the applicant issued the "First Annual Amendment to Application for License Renewal," which documents this information and, therefore, Confirmatory Item 4.1.3-1 is closed.

The loss of prestress on containment tendons is time-dependent as a result of age-related degradation, such as creep and shrinkage of concrete, stress relaxation, corrosion, and anchorage seating losses. The calculation of normalized liftoff force of tendons specified in the technical specification Figures 3.6.1-1, 3.6.1-2, and 3.6.1-3 is a TLAA. The technical specification surveillance test is a measure of liftoff force to ensure that the prestress loss of tendons is within acceptable limits. The applicant has stated that the curves in the technical specification pertaining to the predicted liftoff force will be recalculated by the year 2012 to account for the period of extended operation. The staff considered the deferral of the recalculation of predicted liftoff force for the license renewal term to be Open Item 4.1.3-2. On the basis of the discussion in Section 3.10 on the closure of Open Item 3.10.3.2.1-1, Open Item 4.1.3-2 is closed.

The criticality analyses for the Unit 1 spent fuel pool (SFP) is a TLAA due to age related depletion of boron-10 used as a neutron-absorbing material between spent fuel assemblies. The applicant has performed an aging analysis for the poison sheets in both SFPs and has determined that there are plausible aging mechanisms in both SFPs requiring an aging management program for the period of extended operation. This is discussed in Section 3.3E of Appendix A to the LRA. The neutron-absorbing sheets installed in Unit 2 are constructed of a material called Boraflex. The applicant, however, has stated that the Unit 2 criticality analysis does not assume any loss of boron concentration from aging and, therefore, is not treated as a TLAA. The staff has determined that the effect of aging on the intended function of the SFP poison sheets will be adequately managed for the period of extended operation with the coupon surveillance program for monitoring the condition of neutron-absorbing materials in both SFPs. This aging management program is evaluated in Section 3.10 of this SER.

The staff had requested information from the applicant justifying not identifying metal corrosion allowances for Class I and II piping as a TLAA. Each ASME Code component is provided with a corrosion allowance for material subject to thinning by corrosion during the design life of the component by a suitable increase in thickness over that determined by the design formulae and, therefore, it should be treated as a TLAA. However, the applicant responded to the staff's RAI indicating that there was no corrosion allowance in any design calculation and, therefore, it is not a TLAA. The applicant stated at a site meeting on February 17, 1999 (as documented in NRC meeting summary dated March 19, 1999), that there were programs in place for mitigation and discovery of corrosion in piping during the period of extended operation. These aging management programs are evaluated in Section 3.1 of this SER. The staff considers this item resolved.

The staff also noted that the applicant did not identify inservice flaw growth analysis as a TLAA. The applicant stated at the site meeting held between February 16 and 18, 1999 (as documented in NRC meeting summary dated March 19, 1999), that there was no inservice flaw growth that was analyzed for the current license term. Therefore, inservice flaw growth has not been treated as a TLAA.

With respect to metal fatigue (from thermal cycles) of United States of America Standard (USAS) B31.7 Class 2 and 3 piping components (other than main steam piping), the applicant stated in the same meeting that these components have a stress limit based on 7000 cycles and, further, its data search did not identify this issue as a TLAA. In the application, however, the applicant discussed expected cycles during the period of extended operation for some components. These assessments are TLAAs. In addition, during the site meeting, the applicant indicated that the number of cycles was considered in its evaluation of Class 2 and 3 piping. The fatigue assessment was considered as a TLAA and, hence, was identified as Open Item 4.1.3-3. In a letter dated July 2, 1999, the applicant presented its rationale for determining that thermal fatigue for Class 2 and 3 systems (other than main steam piping) was not plausible. The rationale stated that, during the aging management review process for the Class 2 and 3 systems, the applicant considered fatigue a potential ARDM. For the Class 2 and 3 systems where the LRA identifies fatigue as not plausible, the applicant considered the following to make the not plausible determination:

1. The ΔT between system shutdown temperature and maximum operating temperature. If the ΔT was small (equal to or less than 50°F), fatigue was not plausible.

2. If the ΔT was greater than 50°F, the applicant conservatively estimated the number of thermal cycles for 60 years using plant operating history. If the number of thermal cycles was less than the design number of cycles, fatigue was not plausible.

The applicant did not conclude that this was a TLAA.

The staff considers the applicant's fatigue evaluations of the Class 2 and 3 systems, as discussed above, constitute TLAAs. However, the staff finds that these evaluations satisfy the requirements of 10 CFR 54.21(c)(1)(i) and Open Item 4.1.3-3 is closed.

In response to the staff's RAI, and the clarification presented by the applicant at the above site meeting in February, the staff resolved the following items as not being considered in the evaluation of TLAAs since these items do not involve time-limited assumptions defined by the current operating term pursuant to definitions provided in 10 CFR 54.3:

- High-energy pipe break postulation (since the design is not based on fatigue cumulative usage factor and there is no time-dependent analysis used).
- Fatigue of polar crane (since the design is solely based on number of load cycles at or below the rated load, not for a service life of 40 years).
- Fatigue of reactor coolant pump flywheel (since the fatigue of RCP flywheel is based on endurance limit which is independent of the number of cycles).
- Underclad cracking of reactor vessel (since CCNPP has no experience with this aging effect).
- High-cycle fatigue of reactor vessel internals (since the design is based on endurance limit which is independent of number of cycles).

4.1.4 Conclusion

The staff concludes that the applicant has provided a list of acceptable TLAAs involving systems, structures, and components other than electrical equipment (see Section 4.2 of this SER) as defined in 10 CFR 54.3. For each specific TLAA, the applicant has provided information as the bases to justify compliance with 10 CFR 54.21(c)(1)(i), (ii), or (iii).

4.2 Environmental Qualification (EQ) of Electric Equipment

The applicant has identified the 10 CFR 50.49 program as a TLAA for the purposes of license renewal. The TLAA aspect of EQ encompasses all long-lived EQ equipment whether active or passive and, each equipment qualification file (EQF) for a long-lived component documents a TLAA.

4.2.1 Introduction

The staff has reviewed Section 6.3.3 of Appendix A to the LRA to determine whether the applicant provided adequate information to meet the requirements in 10 CFR 54.21(c)(1) regarding an evaluation of the EQ TLAA and Section 6.3.4 regarding the EQ Generic Safety Issue (GSI-168).

4.2.2 Summary of Technical Information in the Application

The applicant is implementing 10 CFR 54.21(c)(1)(iii) for the EQ TLAA to demonstrate that the effects of aging on the intended function(s) of EQ equipment will be adequately managed for the period of extended operation. The methodology used to evaluate the EQ TLAA is as follows:

Extending Component Qualified Life

Before the end of it's qualified life, equipment is replaced with qualified new equipment and preventive maintenance is scheduled to initiate and execute these replacements. Qualified life reevaluations are an ongoing activity and take actual normal operating conditions as compared to design maximums into consideration. Equipment qualified lives are adjusted up or down accordingly, based on the following steps:

- Original qualified life bases are reviewed, including assumptions, margin, uncertainty, and sensitivity factors.
- Margin and uncertainty limits are established for qualified life.
- Any condition monitoring data are reviewed.
- Available specimen test data are reviewed for impact on and validation of margin/uncertainty.
- Qualified life is adjusted based on analysis and test data, condition monitoring data, and refurbishment.
- New replacement dates for qualified equipment and condition-monitoring requirements are established.

Acceptance Criteria for Judging Component Adequacy

As discussed above, reevaluation and/or replacement at or before the end of qualified life will be the methods for dispositioning a TLAA that determines that a component's qualified life falls short of the end of the period of extended operation. The component will be scheduled for replacement at or before the end of its qualified life if the reevaluated qualified life falls short of the end of the period of extended operation. These are the same actions currently taken for short-lived EQ components under the EQ program.

Corrective Actions

The only corrective action currently taken because of the applicant's EQ program is replacement with new equipment, qualified in accordance with 10 CFR 50.49, before the end of the EQ equipment's qualified life. This corrective action is taken if reevaluation of an EQ component's qualified life falls short of the period of extended operation, which is the same corrective action that will be used during the period of extended operation.

Sound Reasons to the Contrary

The 10 CFR 50.49 requirement to upgrade replacement equipment, unless sound reasons to the contrary exist, are addressed by the applicant internally by EN-1-103, "Control of 10 CFR 50.49 Environmental Qualification of Electrical Equipment," and PM-1-101, "Procurement and Control of Items and Services for Calvert Cliffs." The requirements and responsibilities for upgrading replacement equipment are outlined in EN-1-103 and the implementing procedure for upgrading replacement equipment is contained in PM-1-101, which controls the preparation and review of procurement requirements for EQ equipment replacements.

Refurbishment

The applicant utilizes refurbishment as a process to restore designated (qualified) life to the EQ component by replacement of materials and/or subcomponents of the EQ component, which have been identified in the EQ documentation as life-limiting/susceptible to significant degradation due to aging. For EQ equipment that has a designated qualified life based on preconditioning, refurbishment by replacing certain materials of construction and/or subcomponents is based on the level of preconditioning performed on the equipment. Certain EQ equipment qualified to the Division of Operating Reactor Guidelines and NUREG-0588 Category II was not required to be preconditioned.

Ongoing Qualification

The regulation in 10 CFR 50.49(e)(5) states that, "[t]he equipment must be replaced or refurbished at the end of its designated life unless ongoing qualification demonstrates that the item has additional life." Ongoing qualification as defined in IEEE 323-1974, Section 6.6, and in NRC Regulatory Guide 1.89, Revision 1, Section C.5.d can be utilized to demonstrate that an item has additional life. Even though the applicant has not previously used ongoing qualification, the applicant may use it in the future and considers ongoing qualification to be part of the current licensing basis.

Reanalysis

- Thermal Environment

  The underlying assumption of this parameter is that the plant's operating ambient temperatures, either design maximums or conservative bounding values, should be representative of what the component will see during its installed life. The applicant utilized design maximum temperatures for both inside and outside containment to perform the current qualified life calculations/evaluations for the EQ TLAAs. The containment and the auxiliary building are instrumented with temperature sensors installed in locations representative of the general areas to ensure that these areas are maintained at or below their respective design maximum values. Since initial installation, alarms/indication with alarm setpoints and proceduralized operator actions have existed to prevent/minimize temperature excursions above the design maximums. Monitoring frequencies of containment temperatures are controlled by the technical specifications (TSs) and excursions above the design maximum temperatures are controlled by the TS limiting condition for operation. The auxiliary building's normal operating temperatures are controlled at or below the design maximums identified in Updated Final Safety Analysis Report (UFSAR) Section 9.8 to maintain qualified life underlying assumptions.

The applicant's corrective action process was used in response to NRC Information Notice (IN) 89-30 and IN 89-30, Supplement 1, "High Temperature Environments at Nuclear Power Plants," in which periodic temperature surveys were conducted and results were recorded. High-temperature conditions greater than the general area temperatures were quantified and incorporated into the EQ program and into the design change process.

Normal plant operating temperature data collection methods over the years have been performed by a number of techniques, including temperature dots installed in plant areas on equipment, hand-held temperature devices, infrared surveys, automatic temperature data collection equipment, and plant-installed components (i.e., TS containment temperature monitors/operations logs). The highest temperature monitored during each month plus margin was used over 12 months to develop a yearly plant area profile. The resultant plant area profiles are identified in engineering standard ES-014. These conservatively established yearly profiles were input into the thermal qualified life calculations of various short-lived EQ components, utilizing the degradation-weighted average temperature methodology to generate revised qualified lives. The primary method for EQ TLAAs to extend their existing 40-year thermal qualified lives will be the degradation-weighted average temperature methodology based on yearly temperature profiles.

EN-1-103 is the controlling procedure for the EQ program, and periodic monitoring in accordance with PEG-11 (EQ temperature-monitoring program) will continue to revalidate that the conservatively established yearly area profiles remain valid. CCNPP has not implemented any major modifications or experienced any events of sufficient duration that revised the maximum design temperatures so the use of these temperatures in qualified life calculations/evaluations are representative of what is expected to be seen by the component during its installed life.

No changes to currently approved methodology and/or acceptance criteria, including the use of Arrhenius methodology to evaluate thermal aging, have been made by the applicant, nor are any planned in the future, including the period of extended operation.

- Radiation Environment

  The underlying assumption for this parameter is that the normal radiation doses used in the radiation qualified life calculations/evaluations are normally expected or representative. In response to NRC Information Notice 93-39, "Radiation Beams from Power Reactor Biological Shields," utilizing CCNPP's corrective action process, the applicant performed (one fuel cycle) monitoring of the actual containment doses. On the basis of this monitoring, revised maximum, 40-year, radiation doses, greater than the original design values, were established and integrated into the EQ program, as well as the design change process. Engineering standard ES-014 lists the revised 40-year, normal inside-containment doses for these specific plant areas.

  Normal operating, 40-year outside-containment radiation doses were established for the EQ program based on radiological survey records. Auxiliary building monthly radiological surveys were reviewed and the highest dose rate value was recorded each month for each plant area. The average dose rate values were multiplied by 350,400 (the number of hours in 40 years) to obtain the total 40-year normal radiation dose. Engineering standard ES-014 lists the 40-year, normal outside containment doses for these specific plant areas.

  Normal operating 60-year doses, for both inside and outside containment, will be developed, based on radiological survey records. The 40-year radiation doses will be multiplied by 1.5 to reflect the 20 additional years of extended plant operation. These 60-year projections will then be utilized to evaluate the EQ TLAAs, in category 10 CFR 54.21(c)(1)(iii), to determine if existing EQ radiation qualification documentation envelops these projected 60-year doses. Revised qualified lives, based on these 60-year doses, added to the applicable accident doses, will then be defined.

- Plant Environmental Changes

  Engineering standard ES-014 identifies both normal operating and accident design ambient environmental service conditions. Any changes to these environmental service conditions are controlled within the design change process. ES-014 also identifies the design maximum normal operating ambient service conditions of the harsh environment areas, including thermal and radiation hot spots. These environmental service condition changes are reviewed for impact on the EQ program, including the EQ TLAAs, and required changes to the EQ documentation files.

Timing of Resolution

The qualified life of EQ equipment is reassessed, according to existing procedures, sufficiently in advance of the end of qualified life to determine if a revised qualified life can be established, or if equipment replacement is necessary to maintain EQ functional continuity.

EQ Generic Safety Issue (GSI)

There are three options available to resolve issues associated with license renewal which are the subject of a GSI. These three options, listed in the applicant's IPA methodology, are:

- If the issue is resolved before submittal of the renewal application, the applicant can incorporate the resolution into the application;

- An applicant can justify that the CLB will be maintained until a point when one or more reasonable options would be available to adequately manage the effects of aging; or

- An applicant could develop a plant-specific program that incorporates a resolution to the aging issue.

For the EQ GSI, the applicant is opting for the second of the approaches identified above in that it will continue to manage the effects of aging in accordance with the CLB, modified as appropriate to address regulatory changes.

4.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(c)(1), the staff reviewed Section 6.3.3 of Appendix A to the LRA to determine whether the applicant provided adequate information to meet the requirements to demonstrate that the effects of aging on the intended function(s) of EQ equipment will be adequately managed for the period of extended operation. Section 6.3.4 was also reviewed regarding the EQ GSI. After completing the initial review, the staff met with the applicant on October 22,1998, to discuss the applicant's EQ program and, by letter dated January 7, 1999, the staff requested clarification of the EQ options that describe how the procedures for compliance with 10 CFR 50.49 adequately manage EQ TLAA's pursuant to Section 54.21(c)(1)(iii). During a conference call on January 22, 1999, clarification of the January 7, 1999, NRC letter was discussed. By letter dated February 19,1999, the applicant responded to the staff's request for clarification of the EQ options.

The applicant is implementing 10 CFR 54.21(c)(1)(iii) for the EQ TLAA to demonstrate that the effects of aging on the intended function(s) of EQ equipment will be adequately managed for the period of extended operation. The methodology described by the applicant to evaluate the TLAA was reviewed by the staff in the following areas:

- extending component qualified life
- acceptance criteria for judging component adequacy
- corrective actions
- sound reasons to the contrary (for replacement equipment)
- refurbishment
- ongoing qualification
- reanalysis
- thermal environment
- radiation environment
- plant environmental changes
- timing of resolution

The staff's evaluation of the applicant's EQ program was focused on the program elements and process description provided by the applicant. The applicant is using standard approved EQ methodology and acceptance criteria applicable to EQ as defined by NRC Bulletin 79-01B (Division of Operating Reactor Guidelines) including Supplements 1, 2, and 3; NUREG-0588, Revision 1; 10 CFR 50.49; Regulatory Guide 1.89, Revision 1; various NRC generic letters and information notices; and NRC safety evaluation reports on EQ. The applicant's current actions for short-lived equipment are also acceptable for long-lived EQ equipment. The staff concurs with the EQ methodology described by the applicant for the period of extended operation.

The staff's evaluation of the applicant's response to GSI-168 finds it acceptable and consistent with the June 2, 1998, staff guidance to industry which states:

- GSI-168 issues have not been defined to a point that a license renewal applicant can be reasonably expected to address these issues, specifically at this time and,

- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation.

4.2.4 Conclusions

The staff has reviewed the information in Sections 6.3.3 and 6.3.4 of Appendix A to the LRA and additional information provided in the October 22,1998, meeting with the staff; the January 22, 1999, conference call; and the applicant's February 19,1999, letter to NRC. On the basis of this review as presented above, the staff concludes that the applicant has provided an acceptable demonstration that the CCNPP 50.49 EQ program will adequately manage the aging effects associated with all long lived active and passive EQ equipment so that there is reasonable assurance that this EQ equipment will perform its intended function in accordance with the CLB during the period of extended operation.

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

During the 462nd meeting, May 5–8, 1999, the Advisory Committee on Reactor Safeguards (ACRS) reviewed the NRC staff's safety evaluation report (SER) related to the license renewal application for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. The ACRS Subcommittee on Plant License Renewal also reviewed the SER on April 28–29, 1999. Results of the two reviews are documented in an ACRS letter dated May 19, 1999. The letter noted that there were a number of open and confirmatory items that must be resolved before the staff could complete the safety evaluation for the renewal application. The staff responded to the ACRS letter on June 28, 1999. The staff's response states that "the staff will arrange to meet with the Committee to describe the resolution of the open issues and confirmatory items, as soon as the technical basis for the resolution has been settled." The staff forwarded a closure report for open and confirmatory items to the Committee on November 3, 1999. The staff briefed the ACRS subcommittee on Plant License Renewal on November 18, 1999, and the ACRS full committee on December 2, 1999, regarding the resolution of the open and confirmatory items.

During the 468th meeting, December 2–4, 1999, the ACRS completed its review of the Calvert Cliffs license renewal application, as documented in a letter dated December 10, 1999. In the letter the ACRS concluded, in part, that the applicant had properly identified the structures, systems and components that are subject to aging management programs; that the programs instituted to manage aging-related degradation of the identified structures, systems, and components were appropriate and provided reasonable assurance that Calvert Cliffs Nuclear Power Plant, Units 1 and 2 can be operated in accordance with their current licensing basis for the period of the extended license without undue risk to the health and safety of the public; that the NRC staff had performed a comprehensive and thorough review of the applicant's application; that the additional programs required by the NRC staff are appropriate and sufficient; that the current regulatory requirements and existing applicant programs provide adequate management of aging-induced degradation for those components withing the scope of license renewal; that the applicant and NRC staff have identified possible aging mechanisms associated with passive long-lived components; and that no issues warranting additional NRC staff action were identified. A copy of the December 10, 1999 letter is included in this report.

Review by the Advisory Committee on Reactor Safeguards

December 10, 1999

The Honorable Richard A. Meserve
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Dear Chairman Meserve:

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR CALVERT CLIFFS NUCLEAR POWER PLANT, UNITS 1 AND 2

During the 468th meeting of the Advisory Committee on Reactor Safeguards, December 2-4, 1999, we completed our review of the Baltimore Gas and Electric Company's (BGE's) application for license renewal of the Calvert Cliffs Nuclear Power Plant (CCNPP), Units 1 and 2 and the related Final Safety Evaluation Report (FSER). Our review included four meetings with the staff and the applicant concerning the license renewal of CCNPP and two meetings with the staff and the Nuclear Energy Institute concerning generic license renewal issues. During this review, we had the benefit of discussions with representatives of the NRC staff and BGE. We also had the benefit of insights gained from our review of another license renewal application and of the documents referenced. We provided an interim letter, dated May 19, 1999, concerning the BGE application.

Conclusion

On the basis of our review of BGE's application, the FSER, and the resolution of the open and confirmatory items identified in the Safety Evaluation Report (SER), we conclude that BGE has properly identified the structures, systems, and components (SSCs) that are subject to aging management programs. Furthermore, we conclude that the programs instituted to manage aging-related degradation of the identified SSCs are appropriate and provide reasonable assurance that Calvert Cliffs Nuclear Power Plant, Units 1 and 2 can be operated in accordance with their current licensing basis for the period of the extended license without undue risk to the health and safety of the public.

Background and Discussion

This report is intended to fulfill the requirement of 10 CFR 54.25 that each license renewal application be referred to the ACRS for a review and report. BGE requested renewal of the operating licenses for the CCNPP, Units 1 and 2 for a period of 20 years beyond the current license term. The FSER documents the results of the staff's review of information submitted by BGE, including those commitments that were necessary to resolve open and confirmatory items identified by the staff in its SER. The staff's review included the verification of the completeness of the identification and categorization of the SSCs considered in the application; the validation of the integrated plant assessment process; the identification of the possible aging mechanisms associated with each passive long-lived component; and the adequacy of the aging management programs. The staff also conducted onsite inspections to verify the implementation of these programs.

The staff's SER identified a number of open and confirmatory items. The staff and BGE have now resolved all the open and confirmatory items, in part, through additional commitments made by BGE. The BGE commitments to be added to its Final Safety Analysis Report (FSAR) will become a part of the plant's licensing basis and are enforceable.

The commitments made by BGE are adequate to resolve the open and confirmatory items. Several of the open items such as the effects of the reactor coolant environment on fatigue life and the thermal fatigue of American Society of Mechanical Engineers (ASME) Class 1 small-bore piping may have generic implications for other applications for license renewal.

BGE committed to the implementation of a plant-specific monitoring program in which it will use correlations published in NUREG/CR-5704 to calculate the effects of the reactor coolant environment on fatigue life of components and piping. The correlations reflect data developed to resolve Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." We concur with the staff's conclusion that BGE's proposed program is an acceptable plant-specific approach for the resolution of GSI-190 concerns.

BGE resolved an open item concerning cracking of ASME Class 1 small-bore piping by including small-bore piping in the CCNPP's age-related degradation inspection (ARDI) program. Under the ARDI program, inspections of small-bore piping will be performed during the last five years of the current license term. The timing of these inspections is appropriately set late in the current licensing period so that they will be most useful for assessing the need for additional requirements. We concur with the resolution of this open item.

Another open item concerned the adequacy of the bases provided to justify the use of one-time inspections to resolve some potential aging issues. The staff has accepted one-time inspections prior to the end of the current license term, rather than regular, periodic inspections, in those cases in which age-related degradation is not expected to occur. In such cases, the one-time inspection is intended to confirm the expectation that age-related degradation is not occurring, or that its effects are insignificant. We agree that this is an appropriate approach to address such aging issues. We reviewed the basis for the staff's acceptance of one-time inspections in individual cases (SER open Item 3.1.6.3-1) and concur with the staff's determination.

During our meeting, BGE informed us that it expects to conduct most of the one-time inspections after 30 years of plant operation. We believe that it is important that these one-time inspections be performed late in the current license term (the last ten years).

After the SER was issued, the staff identified void swelling as a potential mode of degradation for pressurized water reactor vessel internals. BGE committed to participate in the industry programs to address the significance of void swelling and to develop an inspection program if needed.

As CCNPP, Units 1 and 2 age, inspection and operating experience may prompt significant adjustments to their aging management programs. BGE is required to document in its FSAR that the 10 CFR Part 50 Appendix B quality assurance program also applies to those nonsafety-related SSCs which are subject to an aging management review. Furthermore, the staff has required that BGE include in its FSAR the license renewal application commitments that the staff relied on to conclude that aging effects will be adequately managed for the period of extended operation. These steps ensure that future changes can be controlled under the 10 CFR 50.59 process. Future schedule changes will require license amendments if the schedules are delayed.

The staff has performed a comprehensive and thorough review of the BGE application. The additional programs required by the staff are appropriate and sufficient. Current regulatory requirements and existing BGE programs provide adequate management of aging-induced degradation for those components within the scope of the license renewal rule.

We believe that the applicant and the staff have identified possible aging mechanisms associated with passive long-lived components. Adequate programs have been established to manage the effects of aging so that CCNPP, Units 1 and 2 can be operated safely in accordance with their licensing basis for the period of the extended license.

Dr. William J. Shack did not participate in the Committee's deliberations on aging-induced degradation.

Sincerely,

Signed by

Dana A. Powers
Chairman

<u>References:</u>

1. Letter dated November 16, 1999, from Christopher I. Grimes, Office of Nuclear Reactor Regulation, NRC, to Charles H. Cruse, Baltimore Gas and Electric Company, Subject: Final Safety Evaluation Report.
2. Letter dated May 19, 1999, from Dana A. Powers, Chairman, ACRS, to William D. Travers, Executive Director for Operations, NRC, Subject: Interim Letter on the Safety Aspects of the Baltimore Gas and Electric Company's License Renewal Application for Calvert Cliffs Nuclear Power Plant, Units 1 and 2.
3. U. S. Nuclear Regulatory Commission, NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999.

4. U. S. Nuclear Regulatory Commission, “Safety Evaluation Report Related to the License Renewal of Calvert Cliffs Nuclear Power Plant, Units 1 and 2,” March 1999.
5. Letter dated April 8, 1998, from Charles H. Cruse, Baltimore Gas and Electric Company, to U. S. Nuclear Regulatory Commission Document Control Desk, Subject: Calvert Cliffs Nuclear Power Plant Unit Nos. 1 and 2, Application for License Renewal.
6. U. S. Nuclear Regulatory Commission, Code of Federal Regulations, 10 CFR Part 54, “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”
7. U. S. Nuclear Regulatory Commission, Code of Federal Regulations, 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”

6 CONCLUSIONS

The staff performed its review of the Calvert Cliffs license renewal application in accordance with Federal regulations and the NRC draft Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants dated September 1997. The standards for issuance of a renewed license are set forth in 10 CFR 54.29.

In the safety evaluation report (SER) issued on March 21, 1999, the staff identified a number of open and confirmatory items. All of those items have been resolved, as discussed in this SER. On the basis of its evaluation of the application as discussed above, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. The staff notes that the results of the staff's environmental review are documented in the final plant-specific supplement to the Generic Environmental Impact Statement.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and BGE, as well as public notices, regarding the review of the license renewal application for Calvert Cliffs Nuclear Power Plant Unit Nos. 1 and 2 under Docket Numbers 50-317 and 50-318.

December 6, 1999	BGE letter (From C. Cruse) forwarding specific information needed to support the 10 CFR 54.29 finding for the licence renewal application for Calvert Cliffs Nuclear Power Plants, Unit 1 & 2. ACN: 99340087 Fiche:
November 30, 1999	NRC letter (from C. Grimes) forwarding staff response to November 12, 1999 letter regarding specific information needed to support the 10 CFR 54.29 finding for the licence renewal application for Calvert Cliffs Nuclear Power Plant, Unit 1 & 2. ACN: 993430073 Fiche:
November 12, 1999	BGE letter (from C. Cruse) forwarding specific information needed to support the 10 CFR 54.29 finding for the licence renewal application for Calvert Cliffs Nuclear Plants, Unit 1 & 2. ACN: 993220089 Fiche:
September 7, 1999	NRC letter (from D. Solorio) summarizing of August 27,1999, meeting with BGE in Rockville, MD, to discuss status of NRC review of BGE license renewal application for plants units. ACN: 9909140026 Fiche: A9193 170 A9193 248
August 12, 1999	NRC notification (from D. Solorio) of August 27 meeting with BGE & DPC in Rockville, MD regarding status of review of BGE & Duke license renewal applications for plants. ACN: 9908160111 Fiche: A8965 276 A8965 279
July 16, 1999	BGE letter (from C. Cruse) forwarding comments from accuracy review of license renewal application SER dated March 21, 1999. ACN: 9907210220 Fiche: A8674 304 A8674 340
July 14, 1999	NRC notification (from D. Solorio) of July 28, 1999 meeting with utilities in Rockville, MD, to discuss status of review of BGE & Duke license renewal applications for CCNPP, Units 1 & 2 & ONS, Units 1,2 & 3, respectively. ACN: 9907190107 Fiche: A8606 325 A8606 328

July 1, 1999	NRC letter (from D, Solorio) summarizing March 3, 1999, meeting with BGE in Rockville,MD, to discuss status of NRC review of BGE license renewal application for Calvert Cliffs Nuclear Power Plant, Unit 1 & 2. ACN: 9907120300 Fiche: A8545 284 A8545 307
July 1, 1999	NRC letter (from D. Solorio) summarizing June 30, 1999, meeting with licensees in Rockville, MD, regarding license renewal activities. ACN: 9907120009 Fiche: A8529 004 A8529 037
July 1,1999	NRC letter (from D. Solorio) summarizing January 14, 1999, meeting with BGE in Rockville, MD, regarding status of NRC review of BGE license renewal application for Calvert Cliffs Units 1 & 2. ACN: 9907080361 Fiche: A8524 207 A8524 237
July 2, 1999	BGE letter (from C. Cruise) forwarding responses to open & confirmatory items based on review of SER for BGE application for renewal of operating licenses for Calvert Cliffs. BGE intends to forward comments based on accuracy verification in near future. ACN: 9907090182 Fiche: A8558 294 A8558 360
June 26, 1999	NRC letter (from W. Travers) informing that staff will arrange to meet with ACRS to describe resolution of open items & confirmatory items as soon as technical basis for that resolution settled regarding license renewal application for Calvert Cliffs, Units 1 & 2. ACN: 9907060181 Fiche: A8492 122 A8492 130
June 24, 1999	NRC letter (from D. Solorio) summarizing December 16, 1998, meeting with BGEI in Rockville, MD, to discuss status of NRC review of BGE license renewal application for Calvert Cliffs plant Units 1 & 2. ACN: 9907010161 Fiche: A8476 195 A8476 226
June 14, 1999	NRC letter (from D. Solorio) summarizing May 12, 1999, meeting with BGE in Rockville, MD, regarding licensee renewal activities for Calvert Cliffs Nuclear Power. ACN: 9906180078 Fiche: A8366 230 A8366 247
June 14, 1999	NRC lettert (from D. Solorio) notifying of June 30, 1999, meeting with BGE & DPC in Rockville, Maryland, to discuss status of review of BGE & DPC license renewal applications for CCNPP Units 1 & 2 & ONS Units 1,2 & 3, respectively. ACN: 9906160165 Fiche: A8352 298 A8352 302
May 21, 1999	NRC Inspection reports 50-317/99-04 & 50-318/99-04 during April 5 through 16, 1999. No violation was noted. Major areas of inspection: potential & plausible aging effects & management of aging effects. ACN: 9905280165 Fiche: A8167 202 A8167 229
May 21,1999	NRC letter (from W. Lanning) forwarding inspection reports 50-317/99-04 & 50-318/99-04 on April 5 through 16, 1999.No violations noted.

	Inspection revealed few potential & plausible aging effects NRC team determined should be included in license renewal application. ACN: 9905280163 Fiche: A8167 199 A8167 229
May 18, 1999	NRC letter (from S. Lee) summarizing Tele-conference of May 5 and 10, 1999, with BGE regarding license renewal application on metal fatigue. ACN: 9905260259 Fiche: A8146 315 A8146 326
May 18, 1999	ACRS letter (from D. Power) informing that during 462nd ACRS meeting on May 5 and 6, 1999, Committee reviewed NRC staff SER regarding license renewal application for CCNPP, Units 1 & 2 ACN: 9905260118 Fiche: A8215 193 A8215 195
May 17, 1999	NRC letter (from S. Hoffman) summarizing of March 30, 1999, meeting with NEI to discuss status of first two license renewal applications, resolution of license renewal issues & establishing position regarding credit for existing programs. ACN: 9905240279 Fiche: A8119 336 A8119 350
April 17, 1999	NRC letter (from D. Solorio) notifying of May 12, 1999, meeting with BGE in Rockville, Maryland, to discuss status of BGE license renewal application for CCNPP, Units 1 & 2. ACN: 9905030309 Fiche: A7853 358 A7853 360
April 8, 1999	NRC letter (from Chairman) forwarding "Monthly Status Rept on Licensing Activities & Regulatory Duties of NRC" for March, 1999. Targets for licensing action age & completion rates & license renewal process for Calvert Cliffs remains on schedule. ACN: 9904200032 Fiche: A766S 170 A7665 286
April 4, 1999	BGE letter (from C. Cruse) providing first annual amendment to BGE license renewal application for CCNPP, Units 1 & 2, as required by 10CFR54. ACN: 9904070049 Fiche: A7485 011 A7485 033
April 2, 1999	NRC letter (from G. Barber) notifying significant licensee meeting 99-17 with utility on April 15, 1999, to discuss with public results of first license renewal inspection performed by NRC at Calvert Cliffs during February 8 through 12, 1999. ACN: 9904090108 Fiche: A7545 287 A7545 290
March 26, 1999	NRC letter (from W. Lanning) forwarding inspection reports 50-317/99-02 & 50-318/99-02 on February 8 through 12, 1999. No violation was noted. Inspection was first of three planned visits to verify CCNPP license renewal in compliance with requirements of rule for license renewal. ACN: 9904050221 Fiche: A7505 039 A7505 056

March 24, 1999	NRC letter (from J. Funches) discussing BGE application filed on April 8, 1998, for renewal of operating licenses DPR-53 & DPR-68 for Calvert Cliffs Units, 1 & 2, for partial exemption from 1OCFR17O fees. ACN: 9904070406 Fiche: A7504 312 A7504 316
March 24, 1999	NRC letter (from J. Funches) informing that author determined that partial exemption from 1OCFRI7O fee requirements appropriate for footnote 4 of license renewal application for Calvert Cliffs Nuclear Power Plants Units 1 & 2,dated April 8, 1998, that staff determines has generic value to industry. ACN: 9903310128 Fiche: A7460 356 A7460 360
March 21, 1999	NRC letter (from D. Matthews) forwarding SER reflecting status of staff review of utility license renewal for Calvert Cliffs Nuclear Power Plants, Units 1 & 2. ACN: 9903290118 Fiche: A7388 001 A7389 180
March 19, 1999	NRC letter (from D. Solorio) forwarding summary of February 10, 1999, meeting with BGE in Lusby, Maryland, regarding license renewal activities for CCNPP, Units 1 & 2 & use of age- related degradation inspections as outlined in February 2. 1999, meeting. ACN: 9903290109 Fiche: A7372 001 A7372 102
March 19, 1999	NRC letter (from D. Solorio) forwarding summary of February 16 and 18, 1999, meetings with BGE in Lusby, Maryland, regarding utility responses to NRC staff requests for additional information on BGE license renewal. ACN: 9903290075 Fiche: A7366 001 A7366 140
March 18, 1999	NRC notification(from D. Solorio) of March 30,19999 meeting with BGE in Rockville, Maryland, to discuss status of review of BGE license renewal application for CCNPP, Units 1 & 2. ACN: 9903240392 Fiche: A7355 179 A7355 181
March 11, 1999	BGE letter (from C. Cruse) forwarding rev 1 to CCNPP, Units 1 & 2 license renewal application Section 6.2, "Electrical Commodities." ACN: 9903170210 Fiche: A7201 325 A7201 352
March 3, 1999	BGE letter (from C. Cruse) forwarding Revision 1 to CCNPP, Units 1 & 2 license renewal application, Section 6.2, "Electrical Commodities." ACN: 9903170210 Fiche: *****:***-*****:***
March 03, 1999	NRC letter (from D. Solorio) discussing December 09, 1999 conference call to clarify NRC Question No. 5.11.4. Requests response in writing if any errors. ACN: 9903050363 Fiche: A7043:299-A7043:301
February 26, 1999	Forwards prepublication version of NUREG-1555, "SRP for Environmental Reviews for NPPs" & prepublication version of

	NUREG-1555,Suppl 1 dealing with operating license renewals for Calvert Cliffs Nuclear Power Plant. ACN: 99031110231 Fiche:A649S 059 A6495 063
February 16, 1999	NRC notification (from D. Solorio) on February 26, 1999 meeting with BGE to discuss status of review of BGE license renewal application. ACN: 9902190341 Fiche: A6889:069-A6889:071 ACN: 9902180333 Fiche: A6888:234-A6888:236
February 12, 1999	NRC notification (from D. Solorio) on February 26, 1999 meeting with BGE to discuss status of review of BGE license renewal application. ACN: 9902180333 Fiche: A6888:234-A6888:236
February 09, 1999	NRC notification (from D. Solorio) on February 16 & 18, 1999 meetings with BGE in Lusby, Maryland to clarify requests for additional information responses as described in February 1, 1999 letter to BGE. ACN: 9902120272 Fiche: A6807:147-A6807:149
February 8, 1999	NRC letter forwarding inspection report 50-317/99-02 & 50-318/99-02 on February 8 through 12, 1999. No violations noted. Major areas inspected: implementation of scoping & screening methodology approved by NRC in final SE, dated April 4. 1996. ACN: 9904050225 Fiche: A7505 042 A7505 056
February 04, 1999	BGE letter (from C. Cruse) forwarding additional information for NRC use in writing SER for CCNPP license renewal application. Items in attachment are either IPA results, changes, errata, or items provided for information. ACN: 9902090133 Fiche: A6760:196-A6760:211
February 03, 1999	NRC letter (from M. Modes) submitting details on listed areas with regard to inspection plan for inspection scheduled on February 3, 1999. ACN: 9902100045 Fiche: A6791:355-A6791:357
February 02, 1999	NRC notification (from D. Solorio) on February 10, 1999 meeting with BGE to discuss age-related degradation inspection described in license renewal application for CCNPP Units 1 and 2. ACN: 9902090069 Fiche: A6784:205-A6784:214
February 01, 1999	NRC letter (from D. Solorio) forwarding RAI clarification regarding BGE responses to NRC questions concerning licensee renewal application for CCNPP. ACN: 9902040260 Fiche: A6743:077-A6743:087
January 28, 1999	NRC letter (from the Chairman) discussing license renewal for operating power reactors. Two applications have been received for renewing operating licenses. The Commission has established an adjudicatory

schedule aimed at completing the license renewal process in 30-36 months.
ACN: 9902090060 Fiche: A6780:342-A6780:345

January 28, 1999 NRC letter (from the Chairman) discussing guidance regarding license renewal for operating power reactors developed in response to FY99 energy and water development appropriations act report.
ACN: 9902080222 Fiche: A6764:310-A6764:311

January 26, 1999 NRC notification (from D. Solorio) of February 4, 1999 meeting with BGE to discuss age-related degradation inspections described in utility license renewal application for CCNPP Units 1 and 2.
ACN: 9901290311 Fiche: A6721:026-A6721:028

January 22, 1999 NRC notification (from L. Doerflein) of significant meeting with BGE in King of Prussia, Pennsylvania on February 1 & 2, 1999, to coordinate inspection activities.
ACN: 9902010135 Fiche: N0033:297-N0033:310

January 07, 1999 NRC letter (from C. Grimes) requesting additional information regarding license renewal application as application relates to staff position on environmental qualification.
ACN: 9901110324 Fiche: A6495:059-A6495:063

December 23, 1998 NRC notification (from D. Solorio) of January 14, 1999 meeting with BGE in Rockville, Maryland to discuss status of review of license renewal application.
ACN: 9812300237 Fiche: A6384:359-A6384:361

December 23, 1998 Staff Requirements Memorandum (signed by J. Hoyle) on December 23, 1998 affirmation session at Rockville, Maryland regarding SECY-98-283 concerning licensing board order dismissing proceeding on ground that the National Whistleblower Center failed to submit contentions by October 1, 1998 deadline.
ACN: 9812290261 Fiche: A6370:294-A6370:294

December 23, 1998 Memorandum and Order (signed by J. Hoyle) stating that, for reasons set forth in document as well as reasons set forth in LBP-98-26, the National Whistleblower Center appeal is denied and LBP-98-26 affirmed.
ACN: 9812230354 Fiche: A6323:204-A6323:230

December 17, 1998 Letter (from B. Montgomery) forwarding figures for investigation of impingement of aquatic organisms at CCNPP from 1975-1995.
ACN: 9812220038 Fiche: A6301:327-A6301:331

December 17, 1998 BGE letter (from C. Cruse) forwarding its responses to November 19, 1998 request for additional information for review of CCNPP Units 1 and 2 integrated plant assessment report for RPVs and control element drive mechanism - electrical system to support the license renewal application.

ACN: 9812220032 Fiche: A6301:323-A6301:326

December 11, 1998 NRC letter (from D. Solorio) forwarding summary of August 20, 1998 meeting with utility in Rockville, Maryland to discuss progress of NRC staff review of utility license renewal application and provide overview of proposed method for evaluating performance.
ACN: 9812210155 Fiche: A6245:154-A6245:190

December 11, 1998 NRC letter (from D. Solorio) forwarding summary of October 22, 1998 meeting with utility in Rockville, Maryland to discuss how BGE addressed license renewal requirements for time-limited aging analyses and generic safety issues as applicable to environmental qualification.
ACN: 9812160262 Fiche: A6213:201-A6213:271

December 10, 1998 NRC letter (from D. Solorio) forwarding summary of November 23, 1998 meeting with BGE regarding review of plant records associated with chemistry and boric acid corrosion inspection programs relied upon in BGE license renewal application.
ACN: 9812160216 Fiche: A6209:030-A6209:079
ACN: 9812160219 Fiche: A6209:035-A6209:042
ACN: 9812160220 Fiche: A6209:043-A6209:066
ACN: 9812160225 Fiche: A6209:067-A6209:079

December 10, 1998 BGE letter (from C. Cruse) forwarding its responses to November 18, 1998 request for additional information regarding NRC question number 4.1.17 on the integrated plant assessment report for CCNPP Units 1 and 2.
ACN: 9812140221 Fiche: A6154:064-A6154:073

December 10, 1998 BGE letter (from C. Cruse) forwarding its response to NRC September 3, 1998 request for additional information on the integrated assessment report regarding metal fatigue to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9812140220 Fiche: A6154:046-A6154:049

December 10, 1998 BGE letter (from C. Cruse) forwarding supplemental response to September 3, 1998 request for additional information on the integrated plant assessment report to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9812140219 Fiche: A6154:050-A6154:054

December 10, 1998 BGE letter (from C. Cruse) forwarding supplemental response to NRC September 7, 1998 request for additional information on the integrated plant assessment report for assessment (Sections 3.3a, 3.3b, 3.3c, 3.3d, 3.3e, and 6.2) to support the license renewal application of CCNPP Units 1 and 2 .
ACN: 9812140215 Fiche: A6154:055-A6154:063

December 10, 1998 BGE letter (from C. Cruse) forwarding its response to November 13, 1998 request for additional information on the integrated plant assessment reports to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9812140214 Fiche: A6154:042-A6154:045

December 03, 1998 NRC notification (from D. Solorio) of December 16, 1998 meeting with BGE in Rockville, Maryland to discuss BGE's license renewal application for Calvert Cliffs Nuclear Power Plant Units 1 and 2.
ACN: 9812080203 Fiche: A6078:204-A6078:206

November 20, 1998 NRC notification (from D. Solorio) of December 3, 1998 meeting with utility in Rockville, Maryland to discuss thermal aging embrittlement criteria for cast and ferrite materials with regard to aging management programs.
ACN: 9811250145 Fiche: A5963:358-A5963:360

November 19, 1998 BGE letter (from C. Cruse) forwarding its responses to September 3, 1998 request for additional information on the integrated plant assessment report for reactor vessel internals system to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9811250039 Fiche: A5953:079-A5953:095

November 19, 1998 BGE letter (from C. Cruse) forwarding its responses to September 3, 1998 request for additional information on the integrated plant assessment report for the reactor coolant system to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9811250033 Fiche: A5953:096-A5953:110

November 19, 1998 BGE letter (from C. Cruse) forwarding its response to August 26, 1998 request for additional information on the integrated plant assessment report for PRVS and CEDM electrical system to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9811250031 Fiche: A5953:038-A5953:055

November 19, 1998 BGE letter (from C. Cruse) forwarding its responses to September 2, 1998 request for additional information on the integrated plant assessment regarding metal fatigue to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9811250030 Fiche: A5952:331-A5952:356

November 19, 1998 BGE letter (from C. Cruse) forwarding its response to September 3, 1998 request for additional information on the integrated plant assessment reports for RCS and for RPVS and CEDM electrical system to support the license renewal application of CCNPP Units 1 and 2.
ACN: 9811250029 Fiche: A5952:320-A5952:330

November 19, 1998	BGE letter (from C. Cruse) forwarding its response to September 7, 1998 request for additional information on the integrated plant assessment reports for CSS and piping segments that provide structural support to support the license renewal application of CCNPP Units 1 and 2. ACN: 9811250026 Fiche: A5953:056-A5953:078
November 19, 1998	BGE letter (from C. Cruse) forwarding its response to September 4, 1998 request for additional information on the integrated plant assessment on generic safety issues to support the license renewal application of CCNPP Units 1 and 2. ACN: 9811250022 Fiche: A5953:111-A5953:118
November 19, 1998	BGE letter (from C. Cruse) forwarding its response to September 7, 1998 request for additional information on the integrated plant assessment reports for structures and electrical commodities to support the license renewal application of CCNPP Units 1 and 2. ACN: 9811250020 Fiche: A5953:001-A5953:037
November 18, 1998	NRC notification (from D. Solorio) of November 23, 1998 meeting with utility in Lusby, Maryland to review material associated with chemistry alloy 600 and boric acid corrosion inspection programs relied on in license renewal application for Units 1 and 2. ACN: 9811240256 Fiche: A5940:336-A5940:338
November 18, 1998	NRC letter (from D. Solorio) discussing September 22, 1998 meeting with representatives of BGE in Rockville, Maryland regarding progress of NRC staff review of BGE license renewal application for CCNPP Units 1 and 2 and clarifies request for additional information 1.4.17. ACN: 9811240107 Fiche: A5946:231-A5946:253
November 17, 1998	BGE letter (from C. Cruse) forwarding its responses to September 1, 1998 request for additional information on the integrated plant assessment report for the spent fuel pool cooling system to support the license renewal application of CCNPP Units 1 and 2. ACN: 9811200005 Fiche: A5902:041-A5902:048
November 16, 1998	NRC letter (from D. Solorio) forwarding summary of September 28, 1998 meeting with utility in Rockville, Maryland regarding license renewal activities for CCNPP Units 1. ACN: 9811240181 Fiche: A5928:180-A5928:259
November 16, 1998	BGE letter (from C. Cruse) submitting its response to September 4, 1998 request for additional information on the integrated plant assessment report for fire protection system. ACN: 9811190065 Fiche: A5893:144-A5893:152

November 16, 1998	BGE letter (from C. Cruse) forwarding its response to NRC August 31, 1998 request for additional information regarding integrated plant assessment report for main steam generator blowdown extraction steam and nitrogen and hydrogen systems to support license renewal activities. ACN: 9811190061 Fiche: A5893:153-A5893:163
November 16, 1998	BGE letter (from C. Cruse) forwarding its responses to September 1, 1998, September 2, 1998, and September 4, 1998 requests for additional information on the integrated plant assessment reports for the HVAC system. ACN: 9811190060 Fiche: A5901:181-A5901:203
November 16, 1998	BGE letter (from C. Cruse) forwarding its response to NRC September 3, 1998 request for additional information regarding the integrated plant assessment report for service water system to support license renewal activities. ACN: 9811190059 Fiche: A5893:135-A5893:143
November 16, 1998	BGE letter (from C. Cruse) forwarding its response to September 1, 1998 request for additional information on the integrated plant assessment report for feedwater system. ACN: 9811190057 Fiche: A5893:164-A5893:177
November 13, 1998	NRC letter (from D. Solorio) forwarding summary of June 24, 1998 meeting with utility in Rockville, Maryland regarding integrated plant assessment process for license renewal. ACN: 9811270075 Fiche: A5954:001-A5954:141
November 13, 1998	NRC letter (from D. Solorio) forwarding summary of June 26, 1998 meeting with BGE in Rockville, Maryland regarding BGE structures and system walkdown program for license renewal. ACN: 9811240152 Fiche: A5928:001-A5928:179
November 13, 1998	NRC letter (from D. Solorio) forwarding summary of June 25, 1998 meeting with BGE in Rockville, Maryland regarding BGE age-related degradation and inspection program for license renewal. ACN: 9811200135 Fiche: A5901:095-A5901:152
November 13, 1998	NRC letter (from R. Anand) forwarding summary of September 15, 1998 meeting with the NEI license renewal task force in Rockville, Maryland regarding prioritization of generic license renewal issues for resolution. ACN: 9811190255 Fiche: A5892:297-A5892:342
November 13, 1998	NRC letter (from S. Hoffman) forwarding summary of October 29, 1998 meeting with NEI, BGE and Duke Energy regarding status of license renewal activities. ACN: 9811190253 Fiche: A5892:343-A5892:360

November 13, 1998	NRC letter (from D. Solorio) forwarding revised request for additional information resulting from BGE comments provided to NRC on September 28, 1998. Requests for additional information numbers 5.10.6 and 4.2.8 are being clarified by this letter. ACN: 9811180095 Fiche: A5891:331-A5891:356
November 13, 1998	NRC letter (from D. Solorio) forwarding summary of August 13, 1998 meeting with BGE in Rockville, Maryland to discuss BGE fire protection evaluation section 5.10 contained within license renewal application. ACN: 9811180044 Fiche: A5876:299-A5876:339
November 13, 1998	NRC notification (from D. Solorio) of November 23, 1998 meeting with utility in Lusby, Maryland to review material associated with chemistry, alloy 600, and boric acid corrosion inspection programs relied on in license renewal application for Units 1 and 2. ACN: 9811170260 Fiche: A5847:353-A5847:355
November 12, 1998	BGE letter (from C. Cruse) forwarding its responses to NRC August 28, 1998 request for additional information on the integrated plant assessment report for generic areas. ACN: 9811170217 Fiche: A5840:235-A5840:247
November 12, 1998	BGE letter (from C. Cruse) forwarding its responses to NRC August 27, 1998 request for additional information on the integrated plant assessment report for CCS. ACN: 9811170215 Fiche: A5840:248-A5840:252
November 12, 1998	BGE letter (from C. Cruse) forwarding its responses to September 7, 1998 request for additional information on the integrated plant assessment report for feedwater system. ACN: 9811170206 Fiche: A5840:253-A5840:260
November 12, 1998	BGE letter (from C. Cruse) forwarding its responses to September 3, 1998 request for additional information on the integrated plant assessment report for saltwater system. ACN: 9811170200 Fiche: A5840:261-A5840:266
November 12, 1998	BGE letter (from C. Cruse) forwarding its response to the NRC request for additional information on the integrated plant assessment report regarding AFWS. ACN: 9811170198 Fiche: A5840:267-A5840:276
November 12, 1998	BGE letter (from C. Cruse) forwarding its response to September 2, 1998 request for additional information regarding integrated plant assessment report for containment isolation group to support review of CCNPP Units 1 and 2 license renewal application. ACN: 9811170197 Fiche: A5840:277-A5840:282

November 09, 1998	BGE letter (from C. Cruse) forwarding its response to NRC September 2, 1998 request for additional information on the integrated assessment report for the safety injection system to support the license renewal application for CCNPP Units 1 and 2. ACN: 9811130036 Fiche: A5826:089-A5826:092	
November 09, 1998	BGE letter (from C. Cruse) forwarding its response to September 3, 1998 and September 24, 1998 requests for additional information regarding integrated plant assessment report for containment spray system to support CCNPP license renewal application. ACN: 9811130033 Fiche: A5826:081-A5826:088	
November 05, 1998	BGE brief (submitted by D. Lewis) in opposition to appeal of National Whistleblower Center. BGE states that the licensing board October 16, 1998 memorandum and order should be affirmed because National Whistleblower Center did not comply with deadline. ACN: 9811060041 Fiche: A5754:298-A5754:350	
November 05, 1998	NRC staff brief (submitted by R. Weisman) opposing appeal of National Whistleblower Center. For reasons set forth in brief, licensing board decision in LBP-98-26 should be affirmed. ACN: 9811100171 Fiche: A5794:184-A5794:221	
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for the containment spray system to support the CCNPP license renewal application. ACN: 9811100106 Fiche: A5857:189-A5857:194	
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for fuel handling equipment and other heavy load handling cranes to support the CCNPP license renewal application. ACN: 9811100064 Fiche: A5854:310-A5854:320	
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for the emergency diesel generator system to support the CCNPP license renewal application. ACN: 9811100050 Fiche: A5857:183-A5857:188	
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment regarding the water chemistry program to support the CCNPP license renewal application. ACN: 9811100046 Fiche: A5857:178-A5857:182	

November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for the chemical and volume control system to support the CCNPP license renewal application. ACN: 9811100041 Fiche: A5857:201-A5857:208
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for the safety injection system to support the CCNPP license renewal application. ACN: 9811100038 Fiche: A5857:213-A5857:219
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information on the integrated plant assessment report for the diesel fuel oil system to support the CCNPP license renewal application. ACN: 9811100034 Fiche: A5857:168-A5857:172
November 04, 1998	BGE letter (from C. Cruse) submitting its response to the NRC request for additional information regarding time-limited aging analyses to support the CCNPP license renewal application. ACN: 9811100029 Fiche: A5823:344-A5823:350
November 02, 1998	NRC letter (from D. Solorio) forwarding clarification of selected requests for additional information on the integrated plant assessment report on metal fatigue to support the CCNPP license renewal application. ACN: 9811100095 Fiche: A5801:256-A5801:273
November 02, 1998	BGE letter (from C. Cruse) submitting its responses to the NRC request for additional information regarding the integrated plant assessment report for the component cooling system to support the CCNPP license renewal application. ACN: 9811060205 Fiche: A5806:339-A5806:346
November 02, 1998	BGE letter (from C. Cruse) forwarding its responses to the NRC request for additional information regarding the integrated plant assessment report for the compressed air system to support the CCNPP license renewal application. ACN: 9811060199 Fiche: A5806:347-A5806:354
November 02, 1998	BGE letter (from C. Cruse) forwarding its responses to the NRC requests for additional information regarding the integrated plant assessment on the scoping process to support the CCNPP license renewal application. ACN: 9811060145 Fiche: A5807:062-A5807:069
November 02, 1998	BGE letter (from C. Cruse) forwarding response to NRC September 3, 1998 and September 24, 1998 requests for additional information regarding the integrated plant assessment report for the diesel fuel oil system to support the CCNPP license renewal application. ACN: 9811050134 Fiche: A5806:019-A5806:025

November 02, 1998	BGE letter (from C. Cruse) forwarding response to NRC August 21, 1998 request for additional information regarding the integrated plant assessment report for the auxiliary feedwater system to support the CCNPP license renewal application. ACN: 9811050132 Fiche: A5806:033-A5806:038
November 02, 1998	BGE letter (from C. Cruse) forwarding its response to NRC September 2, 1998 request for additional information regarding the integrated plant assessment report for the RCS to support the CCNPP license renewal application ACN: 9811050109 Fiche: A5806:026-A5806:032
November 02, 1998	BGE letter (from C. Cruse) forwarding its response to NRC August 28, 1998 and September 24, 1998 requests for additional information regarding the integrated plant assessment report for the saltwater system to support the CCNPP license renewal application. ACN: 9811050105 Fiche: A5806:039-A5806:043
October 30, 1998	BGE letter (from C. Cruse) forwarding Revision 23 to the UFSAR for the Calvert Cliffs Nuclear Power Plant Units 1 and 2. ACN: 9811100021 Fiche: A5811:001-A5811:228
October 30, 1998	BGE letter (from C. Cruse) forwarding the CCNPP technical specification bases, which includes Revisions 1, 2, and 3, performed under the technical specification bases control program (TS 5.5.14). ACN: 9811060092 Fiche: A5774:001-A5775:250
October 26, 1998	Petitioner brief (submitted by S. Kohn) in support of appeal of order denying intervention petition and dismissing proceeding. Requests that Commission vacate decision of board and remand case for proceeding regarding disposition of contentions. ACN: 9811030042 Fiche: A5730:221-A5730:248 ACN: 9811030032 Fiche: A5730:220-A5730:248
October 23, 1998	NRC letter (from the Chairman) expressing appreciation for supporting the Commission's initiative in issuing its recent statement of policy on the conduct of adjudicatory proceedings. ACN: 9811030176 Fiche: A5672:352-A5672:353
October 23, 1998	BGE letter (from C. Cruse) submitting its response to NRC request for additional information raised during September 30, 1998 telcon regarding containment tendon long-term corrective action plan. ACN: 9810280104 Fiche: A5629:197-A5629:202
October 22, 1998	Petition (submitted by C. Wesser) submitted on behalf of National Whistleblower Center requesting extension of page limitation regarding CCNPP license renewal. ACN: 9810230030 Fiche: A5511:305-A5511:305

October 22, 1998	Letter (from E. Julian) expressing appreciation for October 22, 1998 conversation regarding National Whistleblower Center's request for extension of page limitation on appeals to commission. ACN: 9810230026 Fiche: A5511:304-A5511:307
October 21, 1998	Petition (submitted by S. Kohn - National Whistleblower Center) requesting leave to file brief of approximately 25 pages in length. ACN: 9810230032 Fiche: A5511:306-A5511:307
October 16, 1998	Second revised notice of filing concerning RAIs (submitted by S. Kohn) stating that Center should not be required to submit its final list of contentions or final supplement-amended petition until 100 days after BGE responses to RAIs. ACN: 9810210043 Fiche: A5486:264-A5486:350
October 16, 1998	Memorandum and Order (signed by G. Bollwerk) denying intervention petition-hearing request and dismissing proceeding regarding the CCNPP license renewal application. Intervention petition hearing request of petitioner dated August 7, 1998 denied and proceeding terminated. ACN: 9810190041 Fiche: A5430:208-A5430:229
October 13, 1998	First supplemental set of contentions (filed by S. Kohn - National Whistleblower Center) in the matter of CCNPP license renewal application. ACN: 9810190052 Fiche: A5431:007-A5431:010
October 09, 1998	NRC notification (from D. Solorio) of October 29, 1998 meeting with BGE in Rockville, Maryland to discuss status of review of CCNPP license renewal application. ACN: 9810190205 Fiche: A5437:349-A5437:351
October 09, 1998	NRC notification (from D. Solorio) of October 22, 1998 meeting with BGE to discuss environmental qualification of electrical equipment regarding CCNPP license renewal application. ACN: 9810190167 Fiche: A5437:327-A5437:329
October 09, 1998	NRC staff response (signed by M. Zobler) to status report and petitioners motion to be informed of communication between the NRC staff and BGE. Petitioner's request for hearing should be denied and the proceeding should be terminated. ACN: 9810140115 Fiche: A5395:108-A5395:117
October 09, 1998	BGE response (from D. Lewis) to petitioner motion to vacate and reschedule pre-hearing conference. ACN: 9810140112 Fiche: A5395:084-A5395:096

October 09, 1998	NRC staff response (signed by R. Weisman) to petitioners motion to vacate and re-schedule pre-hearing conference. ACN: 9810140105 Fiche: A5395:118-A5395:135	
October 09, 1998	BGE letter (from D. Lewis) forwarding answer to petitioner motion to vacate and reschedule pre-hearing conference. ACN: 9810140097 Fiche: A5395:083-A5395:096 ACN: 9810140087 Fiche: A5395:047-A5395:049 ACN: 9810140069 Fiche: A5395:030-A5395:033	
October 09, 1998	BGE letter (from D. Lewis) forwarding answer to "Petitioner Notice of Filing" stating filing is legally and factually infirm and petition should be dismissed. ACN: 9810140069 Fiche: A5395:030-A5395:033	
October 08, 1998	ASLB Order (from G. Bollwerk) advising that if BGE and NRC wish to address matters in the October 07, 1998 notice, action should be taken as part of responsive filings due on October 09, 1998. ACN: 9810090103 Fiche: A5360:159-A5360:161	
October 07, 1998	Petition (from S. Kohn) requesting that National Whistleblower Center should not be required to submit list of contentions or supplemental-amended petition until at least 100 days after BGE forwarding its responses to NRC requests for additional information. ACN: 9810140073 Fiche: A5407:006-A5407:149	
October 02, 1998	Order (from G. Bollwerk) stating that BGE and the NRC staff have up to and including October 9, 1998 in which to respond to National Whistleblower Center submissions. ACN: 9810050071 Fiche: A5296:074-A5296:076	
October 01, 1998	Affidavit (second) (by M. Claro) affirming that information regarding matter of BGE is true and correct. ACN: 9810050130 Fiche: A5296:139-A5296:143	
October 01, 1998	Letter (signed by S. Kohn) informing that National Whistleblower Center reserves the right to file contentions within 15 days of prehearing conference in matter of BGE CCNPP license renewal. ACN: 9810060061 Fiche: A5315:210-A5315:219	
October 01, 1998	Petitioner motion (signed by S. Kohn) requesting to be informed of communication between NRC staff and BGE. ACN: 9810060039 Fiche: A5315:208-A5315:209	
October 01, 1998	Petitioner motion (signed by S. Kohn) to vacate and re-schedule pre-hearing conference. Requests that motion to vacate be granted and pre-hearing conference be postponed until no sooner than 115 days after August 28, 1998 request for additional information response. ACN: 9810060033 Fiche: A5315:172-A5315:185	

October 01, 1998	Response (from S. Kohn - National Whistleblower Center) to NRC staff and BGE answer to its petition to intervene and request for hearing. ACN: 9810050127 Fiche: A5296:127-A5296:143	
September 29, 1998	Order (signed by G. Bollwerk) stating that ASLB will hold prehearing conference in proceeding regarding issue of standing based on information in National Whistleblower Center August 7, 1998 petition. ACN: 9809300053 Fiche: A5254:351-A5254:353	
September 25, 1998	BGE letter (from C. Cruse) forwarding its response to NRC August 6, 1998 request for additional information regarding review of CCNPP integrated plant assessment report for the radiation monitoring system. ACN: 9809300123 Fiche: A5335:353-A5335:358	
September 24, 1998	NRC letter (from D. Solorio) forwarding numbering system to utility that NRC intends to use in tracking utility responses to the NRC requests for additional information and resolution of responses. ACN: 9810020241 Fiche: A5284:327-A5284:334	
September 24, 1998	NRC letter (from E. Julian) informing that the NRC Office of Secretary experienced problems with dedicated e-mail address. In an effort to maintain an electronic mailbox for parties filing by e-mail, an alternate mailbox has been created. ACN: 9809280054 Fiche: A5232:041-A5232:043	
September 21, 1998	NRC letter (from W. Kane) stating that the listed document designated as containing proprietary material should be withheld from public disclosure per 10cfr2.790. ACN: 9809240283 Fiche: A5241:191-A5241:192	
September 21, 1998	Memorandum and order (signed by G. Bollwerk) stating that the National Whistleblower Center motion to delay prehearing conference is denied, but petition for supplemental extension request granted. ACN: 9809230021 Fiche: A5172:175-A5172:180	
September 18, 1998	BGE letter (from C. Cruse) forwarding Revision 7 to "Calvert Cliffs ISFSI USAR." ACN: 9809240230 Fiche: A5263:271-A5263:341	
September 18, 1998	NRC letter (from R. Weisman) advising that the NRC staff set up a single electronic mail address to receive all communications in proceeding. ACN: 9809230050 Fiche: A5172:211-A5172:211	
September 18, 1998	Petition motion (signed by S. Kohn) to vacate prehearing conference or for extension of time. ACN: 9809230043 Fiche: A5172:204-A5172:208	

September 17, 1998	BGE letter (from C. Cruse) forwarding its responses to questions contained in July 9, 1998 request for additional information for review of CCNPP Units 1 and 2 commodity report for cables. ACN: 9809230045 Fiche: A5226:001-A5226:014
September 17, 1998	Memorandum and order (signed by J. Hoyle) stating that the Commission grants the National Whistleblower Center petition for review and gives additional time until September 30, 1998 to file contentions in proceeding. ACN: 9809180043 Fiche: A5125:347-A5125:351
September 17, 1998	NRC letter (from R. Powell) regarding FOIA request for records. The requested records are available through another public distribution program as described in the enclosure. ACN: 9810060334 Fiche: A5316:065-A5316:068
September 16, 1998	BGE response (from D. Lewis) to petitioner's filing in response to prehearing order. BGE states that the National Whistleblower Center failed to demonstrate standing of at least one admissible contention and that .petition should be dismissed. ACN: 9809220021 Fiche: A5152:259-A5152:262
September 15, 1998	NRC notification (from D. Solorio) of September 28, 1998 meeting with utility in Rockville, Maryland to discuss status of review of BGE license renewal application for plant. ACN: 9809170158 Fiche: A5117:339-A5117:341
September 11, 1998	Petition filing (signed by S. Kohn) in response to board initial prehearing order. NRC should issue appropriate orders to ensure that court of appeals can conduct timely review of procedural matters. ACN: 9809160062 Fiche: A5087:179-A5087:185
September 11, 1998	Petition for review (signed by S. Kohn) requesting Commission review of board August 27, 1998 memorandum and order denying National Whistleblower Center motion for extension of time requested. ACN: 9809160057 Fiche: A5087:167-A5087:178
September 07, 1998	NRC letter (from D. Solorio) forwarding summary of May 6, 1998 meeting with BGE in Rockville, Maryland regarding utility-proposed responses to February 13 and 19, 1998 NRC staff requests for additional information on BGE license renewal feedwater system (5.9) and DFOS (5.7). ACN: 9809220029 Fiche: A5153:001-A5154:072
September 07, 1998	NRC letter (from D. Solorio) forwarding request for additional information regarding review of integrated plant assessment Sections 3.3a, 3.3b, 3.3c, 3.3d, 3.3e, and 6.2. ACN: 9809170284 Fiche: A5119:287-A5119:301

September 07, 1998	NRC letter (from D. Solorio) forwarding additional clarification and incorporating new information gained by the staff through review of utility license renewal application submitted by letter dated April 8, 1998. ACN: 9809180114 Fiche: A5121:014-A5121:020	
September 07, 1998	NRC letter (from D. Solorio) forwarding request for additional information regarding utility October 22, 1997 and March 27, 1998 submittals of plant commodity reports for component supports and piping segments (Sections 3.1 and 3.1a). ACN: 9809210161 Fiche: A5144:109-A5144:119	
September 04, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for fire protection system (5.10) to support the CCNPP license renewal application. ACN: 9809170245 Fiche: A5117:357-A5117:360	
September 04, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment for heating and ventilation systems to support the CCNPP license renewal application. ACN: 9809140281 Fiche: A5055:308-A5055:313	
September 04, 1998	NRC letter (from D. Solorio) forwarding request for additional information regarding licensee April 8, 1998 submittal on integrated plant assessment on the GSIS to support the CCNPP license renewal application. ACN: 9809140305 Fiche: A5055:290-A5055:293	
September 03, 1998	NRC letter (from D. Solorio) forwarding request for additional information on Sections 4.1, 4.2, 5.2, 5.7, 5.15, and 5.16 of the integrated plant assessment to support the CCNPP license renewal application. ACN: 9809160358 Fiche: A5095:345-A5095:352	
September 03, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report regarding the containment spray system to support the CCNPP license renewal application. ACN: 9809180126 Fiche: A5120:342-A5120:345	
September 03, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for reactor vessel internals system to support the CCNPP license renewal application. ACN: 9809170259 Fiche: A5119:219-A5119:227	
September 03, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report for the RCS to support the CCNPP license renewal application. ACN: 9809170233 Fiche: A5119:241-A5119:247	

September 03, 1998 NRC letter (from D. Solorio) forwarding request for additional information in the integrated plant assessment report regarding the service water system to support the CCNPP license renewal application.
ACN: 9809180120 Fiche: A5121:001-A5121:005

September 02, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment reports for the containment isolation group, containment spray system, and primary containment heat and ventilation system to support the CCNPP license renewal application.
ACN: 9809170275 Fiche: A5119:228-A5119:236

September 02, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report regarding the safety injection system to support the CCNPP license renewal application.
ACN: 9809180148 Fiche: A5120:354-A5120:357

September 02, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment reports contained in application against requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(3) to support the CCNPP license renewal application.
ACN: 9809150237 Fiche: A5070:318-A5070:332

September 02, 1998 Letter (from S. Samuel) expressing appreciation for August 28, 1998 letter. Requests the NRC to re-examine the rules and delay relicensing of Calvert Cliffs.
ACN: 9809100179 Fiche: A5047:085-A5047:086

September 02, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report regarding licensee December 17, 1997 submittal of reactor coolant system to support the CCNPP license renewal application.
ACN: 9809140294 Fiche: A5055:294-A5055:297

September 01, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report regarding BGE feedwater system (5.9) to support the CCNPP license renewal application.
ACN: 9809150221 Fiche: A5063:318-A5063:323

September 01, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report regarding utility August 21, 1997 submittal of spent fuel pool cooling system to support the CCNPP license renewal application.
ACN: 9809140290 Fiche: A5055:298-A5055:303

September 01, 1998 NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report regarding the auxiliary feedwater system to support the CCNPP license renewal application.
ACN: 9809170250 Fiche: A5119:302-A5119:306

August 31, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report on the main steam generator blowdown extraction steam and nitrogen and hydrogen system to support the CCNPP license renewal application. ACN: 9809170272 Fiche: A5119:213-A5119:218
August 28, 1998	NRC letter (from C. Grimes) expressing appreciation for June 24, 1998 letter regarding license renewal activities for CCNPP and for concern raised regarding adequacy of emergency preparedness for plant. ACN: 9809080208 Fiche: A4988:330-A4988:344
August 28, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report against the requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(3) to support the CCNPP license renewal application. ACN: 9809080129 Fiche: A4990:192-A4990:197
August 28, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report regarding the saltwater cooling system to support the CCNPP license renewal application. ACN: 9809180051 Fiche: A5120:336-A5120:339
August 27, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for EDG system to support the CCNPP license renewal application. ACN: 9809180039 Fiche: A5120:331-A5120:335
August 27, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment reports contained in application against requirements of 10 CFR 54.21(a)(1) and 10 CFR 54.21(a)(3) to support the CCNPP license renewal application. ACN: 9809150225 Fiche: A5063:352-A5063:356
August 27, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report for component cooling system (5.3) to support the CCNPP license renewal application. ACN: 9809170241 Fiche: A5119:237-A5119:240
August 27, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment for scoping per utility April 8, 1998 submittal to support the CCNPP license renewal application. ACN: 9809140287 Fiche: A5055:304-A5055:307
August 27, 1998	Letter (from D. Lewis) forwarding the same electronic version of BGE application for CCNPP that was provided to ASLB on August 27, 1998. ACN: 9809020042 Fiche: A4903:231-A4903:232 ACN: 9809020038 Fiche: A4903:225-A4903:226

August 27, 1998	NRC staff response (signed by R. Weisman) to National Whistleblower Center request for hearing and petition to intervene. Unless appropriately amended and supplemented, petition should be denied for listed reasons. ACN: 9808310057 Fiche: A4827:289-A4827:300
August 27, 1998	Memorandum and order (signed by G. Bollwerk) denying time extension motion and scheduling prehearing conference. Orders that National Whistleblower Center August 21, 1998 motion for extension of time is denied. ACN: 9808310028 Fiche: A4827:280-A4827:286
August 27, 1998	NRC staff status report (signed by J. Moore) stating that staff intends to issue both final safety evaluation report and final environmental impact statement by 991116. ACN: 9808310024 Fiche: A4827:252-A4827:255
August 26, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report regarding review reactor pressure vessels and control element drive mechanisms-electrical system (4.2) to support the CCNPP license renewal application. ACN: 9809140276 Fiche: A5055:322-A5055:329
August 26, 1998	NRC letter (from D. Solorio) forwarding request for additional information regarding commodity report for fuel handling equipment and other heavy load handling cranes to support the CCNPP license renewal application. ACN: 9809090031 Fiche: A5004:175-A5004:180
August 26, 1998	Notice of appearance (signed by S. Kohn) informing that L. Yolton and M. Claro will enter appearances as counsel on behalf of the National Whistleblower Center regarding Calvert Cliffs Units 1 and 2 license renewal. ACN: 9809020057 Fiche: A4903:233-A4903:234
August 26, 1998	NRC staff response (from J. Moore) to petitioner motion for enlargement of time. Petitioner failed to establish good cause for delaying submission of contentions and prehearing conference, and motion should be denied. ACN: 9808280027 Fiche: A4801:229-A4801:237
August 26, 1998	Memorandum and order (signed by J. Hoyle) denying petition filed by the National Whistleblower Center for intervention and hearing in matter regarding BGE application for renewal of operating license. ACN: 9808280042 Fiche: A4801:274-A4801:285
August 25, 1998	Memorandum (signed by J. Hoyle) discussing Commission belief that meeting with ASLB is not necessary due to policy statements and orders being appropriate mechanisms for caring supervisory role over NRC adjudicatory process. ACN: 9808280106 Fiche: A4836:159-A4836:159

August 25, 1998	Notice of appearance (signed by M. Zobler) stating that M. Zobler, R. Weisman, and J. Moore will enter an appearance in the CCNPP license renewal proceedings per 10 CFR 2.713(b). ACN: 9808280030 Fiche: A4801:269-A4801:273
August 24, 1998	BGE response (from D. Lewis) to petition to intervene and request for hearing of the National Whistleblower center. For reasons discussed, requests that petition be dismissed. ACN: 9808280025 Fiche: A4801:150-A4801:170
August 24, 1998	BGE letter (from D. Lewis) opposing petitioner motion for enlargement of time, and requests that National Whistleblower Center motion for enlargement of time be denied. ACN: 9808280028 Fiche: A4801:238-A4801:243
August 24, 1998	Order (signed by G. Bollwerk) on schedule for responses to motion for extension of time. Orders that any responses to August 21, 1998 motion to extend time for prehearing conference should be filed on or before August 26, 1998. ACN: 9808260030 Fiche: A4778:235-A4778:237
August 21, 1998	Petition motion (signed by S. Kohn) requesting enlargement of time. Petition requests that pre-hearing conference should be set for first week in December 1998, and petitioner amended petition should be filed prior to 15 days before conference. ACN: 9809140066 Fiche: A5064:344-A5064:350
August 21, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for the compressed air system to support the CCNPP license renewal application. ACN: 9808280155 Fiche: A4835:354-A4835:359
August 21, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for the auxiliary feedwater system to support the CCNPP license renewal application. ACN: 9808280153 Fiche: A4836:136-A4836:140
August 21, 1998	Petition (from S. Kohn) moving to vacate order CLI-98-14 stating that the NRC must insure that the effect on petitioner's due process rights caused directly and indirectly by issuance of Part II of order be removed. ACN: 9808260035 Fiche: A4778:259-A4778:275
August 20, 1998	Memorandum and order (initial prehearing order)(signed by G. Bollwerk) requesting that on or before August 28, 1998, the applicant or staff provide board with electronic version and copy of April 1998 renewal application. ACN: 9808210110 Fiche: A4703:178-A4703:191

August 19, 1998	Transcript of August 19, 1998 affirmation session in Rockville, Maryland regarding BGE application for license renewal for CCNPP. ACN: 9808270027 Fiche: A4813:314-A4813:320	
August 19, 1998	Staff requirements memorandum (signed by J. Hoyle) regarding Commission approval of order governing conduct of license renewal proceeding in BGE application for CCNPP. ACN: 9808200213 Fiche: A4698:253-A4698:253	
August 19, 1998	Order (signed by J. Hoyle) referring petition for intervention and request for hearing to ASLB. Commission directs board to conduct proceeding per guidance in this order. ACN: 9808200034 Fiche: A4685:149-A4685:157	
August 19, 1998	Document (signed by B. Cotter) establishing Atomic Safety and Licensing Board, comprised of G. Bollwerk, J. Kline, and T. Murphy. ACN: 9808200029 Fiche: A4685:146-A4685:148	
August 19, 1998	Memorandum (signed by J. Hoyle) forwarding for appropriate action copy of petition to intervene by the National Whistleblower Center with respect to application of BGE to renew operating licenses for CCNPP Units 1 and 2. ACN: 9808200023 Fiche: A4685:043-A4685:053	
August 11, 1998	NRC letter (from D. Solorio) forwarding request for additional information regarding the integrated plant assessment report for the component cooling system to support the CCNPP license renewal application. ACN: 9808170163 Fiche: A4653:315-A4653:319	
August 10, 1998	NRC revised notification (from D. Solorio) of August 13, 1998 meeting with BGE in Rockville, Maryland to discuss NRC staff review of fire protection technical report submitted to support the CCNPP license renewal application. ACN: 9808270187 Fiche: A4812:348-A4812:349	
August 10, 1998	Comment (from B. Johnston) on CCNPP license renewal. ACN: 9808190218 Fiche: A4681:336-A4681:338	
August 07, 1998	Affidavit of M. Claro related to application for license renewal by BGE for CCNPP. ACN: 9808200042 Fiche: A4685:051-A4685:053	
August 07, 1998	Affidavit of L. Yolton related to application for license renewal by BGE for CCNPP. ACN: 9808200037 Fiche: A4685:049-A4685:050	

August 07, 1998	Petition to intervene (signed by M. Kohn) and request for hearing of the National Whistleblower Center. Petitioner seeks leave to intervene in proceedings regarding BGE application to renew operating licenses for CCNPP for 20 years. ACN: 9808200030 Fiche: A4685:044-A4685:048
August 06, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment technical report regarding radiation monitoring system (5.14) to support the CCNPP license renewal application. ACN: 9808100179 Fiche: A4961:076-A4961:079
August 06, 1998	Comment (from R. McLean) on CCNPP license renewal. ACN: 9808190246 Fiche: A4681:347-A4681:349
August 04, 1998	Comment (from B. Auerbach) on CCNPP license renewal. ACN: 9808190242 Fiche: A4681:339-A4681:339
August 03, 1998	NRC notification (from D. Solorio) of August 13, 1998 meeting with BGE in Rockville, Maryland to discuss NRC staff review of fire protection technical report submitted in accordance with BGE license renewal application for CCNPP. ACN: 9808070298 Fiche: A4545:277-A4545:278
July 30, 1998	BGE letter (from C. Cruse) submitting responses to NRC requests for additional information dated February 13 and 19, 1998 for review of plant integrated assessment reports on the feedwater system and diesel fuel oil system. ACN: 9808060027 Fiche: A4563:322-A4563:352
July 28, 1998	Comment (from S. Ebenreck) on CCNPP license renewal. ACN: 9808190109 Fiche: A4681:351-A4681:353
July 28, 1998	NRC notification (from D. Solorio) of August 20, 1998 meeting with BGE in Rockville, Maryland to discuss status of review of BGE license renewal application for CCNPP. ACN: 9807310045 Fiche: A4449:350-A4449:351
July 21, 1998	NRC memorandum (From R. Caruso) forwarding requests for additional information regarding license renewal application ACN: 9807220300 Fiche: A4299:113-A4299:114
July 14, 1998	Comment (from R. Ochs) on CCNPP license renewal. ACN: 9807270402 Fiche: A4352:013-A4352:014
June 24, 1998	Comment (from S. Samuel) on CCNPP license renewal. ACN: 9808190236 Fiche: A4681:340-A4681:346

June 17, 1998	NRC letter (from C. Grimes) forwarding staff proposed safety and environmental review schedule for BGE application submitted on April 10, 1998 to renew operating licenses for CCNPP. ACN: 9806230167 Fiche: A3915:124-A3915:127
June 12, 1998	NRC notification (from D. Solorio) of June 25, 1998 meeting with BGE in Rockville, Maryland to provide overview of utility age-related degradation inspection program and to present comparison between ARDI program elements. ACN: 9806180037 Fiche: A3865:282-A3865:283
June 12, 1998	NRC notification (from D. Solorio) of June 26, 1998 meeting to provide comparison between program elements of licensee system engineer walkdown program and program elements in Standard Review Plan for license renewal. ACN: 9806180027 Fiche: A3867:257-A3867:258
June 12, 1998	NRC notification (from D. Solorio) of June 24, 1998 meeting with BGE in Rockville, Maryland to discuss overview of BGE process for preparing technical reports for license renewal application. ACN: 9806180002 Fiche: A3867:287-A3867:288
June 04, 1998	BGE letter (from C. Cruse) forwarding 24 additional copies of Volumes 1 and 2 of application for CCNPP license renewal in accordance with 10 CFR 50.4(b)(2). ACN: 9806090171 Fiche: A3766:354-A3766:355
May 22, 1998	NRC letter (from T. Essig) informing that staff is continuing review of BGE application for license renewal submitted on April 8, 1998 and requests further discussion to determine compliance with 10 CFR 51.53(c)(3)(iv). ACN: 9805290250 Fiche: A3603:279-A3603:281
May 08, 1998	NRC letter (from C. Grimes) accepting for docketing the application for renewal of licenses of the Calvert Cliffs Nuclear Power Plant Units 1 and 2 for an additional 20 year period. ACN: 9805190050 Fiche: A3477:089-A3477:091
May 08, 1998	NRC letter (from J. Roe) discussing determination of acceptability and sufficiency for docketing BGE's application for renewal of licenses of CCNPP Units 1 and 2, and forwarding notice regarding application. ACN: 9805190042 Fiche: A3477:088-A3477:091
May 08, 1998	BGE letter (from C. Cruse) informing that BGE will not be able to complete requested review to meet NRC requested date of May 11, 1998. BGE will provide evaluation by May 31, 1998. ACN: 9805180277 Fiche: A3517:345-A3517:345

April 08, 1998	BGE letter (from C. Cruse) forwarding application for renewal of licenses DPR-53 and DPR-69 for the Calvert Cliffs Nuclear Power Plant, extending expiration date to 20 years beyond current expiration date. ACN: 9804100416 Fiche: A3021:001-A3025:111 ACN: 9804130002 Fiche: A3021:005-A3025:111
March 27, 1998	BGE letter (from C. Cruse) forwarding integrated plant assessment commodity and system reports and time-limited aging analyses evaluation for review and approval. ACN: 9804030403 Fiche: A2911:001-A2911:170
March 26, 1998	Shaw, Pittman, Potts & Trowbridge letter (from D. R. Lewis) forwarding memorandum presenting position on proper treatment of generic safety issues in license renewal proceedings. ACN: 9803310168 Fiche: A2838:346-A2838:358
March 03, 1998	BGE letter (from C. Cruse) forwarding integrated plant assessment commodity and system reports for review and approval to support the CCNPP license renewal application in accordance with 10 CFR 50.54. ACN: 9803090264 Fiche: A2541:222-A2542:008
February 19, 1998	NRC letter (from D. Solorio) forwarding request for additional information on the integrated plant assessment report for diesel fuel oil system to support the CCNPP license renewal application. ACN: 9803120343 Fiche: A2560:139-A2560:145
February 12, 1998	Letter (from E. Ghigiarelli) informing that Maryland Department of the Environment has reviewed federal consistency certification and supporting information prepared by BGE for renewal of NRC operating license for CCNPP. ACN: 9803130309 Fiche: A2614:250-A2614:252
February 09, 1998	Electric Power Research Institute letter (from J. Carey) forwarding EPRI TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal." ACN: 9803050035 Fiche: A2495:001-A2495:291
January 21, 1998	BGE letter (from C. Cruse) forwarding integrated plant assessment commodity and system reports for review and approval to support the CCNPP license renewal application in accordance with 10 CFR 54. ACN: 9801270121 Fiche: A1931:001-A1931:103
December 31, 1997	Structural Integrity Associates, Inc. letter (from D. Gerber) forwarding final report, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for Calvert Cliffs Nuclear Power Plant." ACN: 9803050038 Fiche: A2495:002-A2495:202

December 17, 1997	BGE letter (from C. Cruse) forwarding integrated plant assessment system reports for review and approval in accordance with 10 CFR 54 license renewal rule. ACN: 9712290007 Fiche: A1634:112-A1634:233
November 28, 1997	NRC letter (from D. Solorio) discussing acceptance review for integrated plant assessment system and commodity group reports per 10 CFR 54 for review by NRC to support license renewal application in case utility determines at later date to formally submit application. ACN: 9712080142 Fiche: A1323:184-A1323:187
November 14, 1997	BGE letter (from C. Cruse) forwarding integrated plant assessment system and commodity reports for review and approval in accordance with 10 CFR 54 license renewal rule. ACN: 9711200146 Fiche: A1204:001-A1204:114
November 04, 1997	NRC letter (from D. Solorio) discussing acceptance review for integrated plant assessment system and commodity group reports. The NRC staff has sufficient information to initiate detailed review of reports. ACN: 9711120261 Fiche: A1069:358-A1069:361
October 22, 1997	BGE letter (from C. Cruse) forwarding integrated plant assessment system and commodity reports for review and approval in accordance with 10 CFR 54 license renewal rule. ACN: 9710310001 Fiche: A0985:005-A0985:168
October 02, 1997	NRC letter (from D. Solorio) informing that the updated working draft of SRP for license renewal was placed in NRC Public Document Room by NRC memorandum from J. Roe to S. Collins dated September 21, 1997. ACN: 9710060105 Fiche: A0633:316-A0633:320
August 21, 1997	BGE letter (from C. Cruse) forwarding integrated plant assessment system and commodity reports for review and approval in accordance with 10 CFR54 license renewal rule. ACN: 9708270006 Fiche: A1566:073-A1566:159
July 30, 1997	BGE letter (from C. Cruse) forwarding Integrated Plant Assessment system reports for review and approval in accordance with 10CFR54 license renewal rule. Amendments will be submitted. ACN: 9708050343 Fiche: 94716:164-94716:219
July 30, 1997	BGE letter (from C. Cruse) forwarding Integrated Plant Assessment Commodity report on environmentally qualified equipment for review and approval in accordance with 10 CFR54 license renewal rule. ACN: 9708040214 Fiche: 94710:129-94710:155

July 30, 1997	BGE letter (from C. Cruse) forwarding Integrated Plant Assessment Commodity report on RPV and control element drive mechanisms/electrical systems for review and approval. ACN: 9708040209 Fiche: 94726:165-94726:205
June 23, 1997	NRC letter (from S. Flanders) acknowledging receipt of four Integrated Plant Assessment System and Commodity reports from BGE. Staff concludes template properly implemented. ACN: 9706240280 Fiche: 93499:202-93499:204
April 16, 1997	Meeting summary (from S. Flanders) of April 08, 1997 meeting with BGE to discuss responses to staff requests for additional information of August 30, 1997. ACN: 9704180136 Fiche: 92532:290-92532:295
March 26, 1997	Meeting summary (from S. Flanders) of February 26, 1997 meeting with BGE to discuss responses to staff requests for additional information of August 30, 1997. ACN: 9703280344 Fiche: 92275:325-92275:341
March 25, 1997	NRC notification (from S. Flanders) of April 08, 1997 meeting with BGE to discuss responses to staff requests for additional information of August 30, 1997. ACN: 9703270111 Fiche: 92254:335-92254:338
March 04, 1997	Meeting summary (from S. Flanders) of January 04, 1997 meeting with BGE to discuss results of 90 day review effort assigned at previous meeting of September 11, 1996. ACN: 9703060322 Fiche: 91991:097-91991:152
February 14, 1997	BGE letter (from C. Cruse) forwarding response to requests for additional information regarding Integrated Plant Assessment System and Commodity reports submitted on May 22, 1996. ACN: 9702200186 Fiche: 91846:193-91846:277
February 12, 1997	NRC notification (from S. Flanders) of February 26, 1997 meeting with BGE to discuss responses to staff requests for additional information of August 30, 1996. ACN: 9702140184 Fiche: 91772:275-91772:278
January 16, 1997	Meeting summary (from S. Flanders) of October 16, 1996 meeting with BGE to discuss license renewal program. ACN: 9701210045 Fiche: 91492:227-91492:257
December 20, 1996	NRC notification (from S. Flanders) of January 09, 1997 meeting with BGE to discuss results of 90-day review effort proposed by NRC at previous meeting of September 11, 1996. ACN: 9612240313 Fiche: 91197:325-91197:328

December 04, 1996	Meeting summary (from S. Flanders) of November 14, 1996 meeting with BGE to provide comments to BGE on sample revisions of BGE's Structures, Component Supports and Main Feedwater Integrated Plant Assessment reports. ACN: 9612090074 Fiche: 91045:207-91045:217
November 29, 1996	Meeting summary (from S. Flanders) of October 10, 1996 meeting with BGE to discuss sample revisions to revisions of BGE's Structures, Component Supports and Main Feedwater Integrated Plant Assessment reports. ACN: 9612050097 Fiche: 91017:139-91017:315
November 20, 1996	Meeting summary (from J. Moulton) of October 24, 1996 meeting with BGE regarding implementation of BGE integrated plant assessment system and commodity reports template. ACN: 9611220284 Fiche: 90902:241-90902:277
November 19, 1996	NRC notification (from S. Flanders) of November 19, 1996 meeting with BGE to discuss staff comments made during November 14, 1996 meetings. ACN: 9611210155 Fiche: 90884:358-90884:359
November 07, 1996	NRC notification (from S. Flanders) of November 14, 1996 meeting with BGE to provide comments on revised portions of component supports, feedwater & structure reports to demonstrate implementation of template in areas of operating experience. ACN: 9611130222 Fiche: 90714:239-90714:239
November 06, 1996	BGE letter (from C. Cruse) responding to NRC requests for additional information regarding integrated plant assessment system and commodity reports. ACN: 9611130393 Fiche: 90725:139-90725:140
October 18, 1996	NRC notification (from S. Flanders) of October 24, 1996 meeting with BGE to provide comments on revisions to component supports, feedwater & structure reports. ACN: 9610220148 Fiche: 90490:225-90490:226
October 15, 1996	Meeting summary (from S. Flanders) of August 08, 1996 meeting with BGE regarding license renewal activities. ACN: 9610170123 Fiche: 90426:008-90426:021
October 11, 1996	Meeting summary (from S. Flanders) of September 20, 1996 meeting with BGE to discuss scope and schedule of 90-day effort proposed at the September 11, meeting with regard to license renewal approach. ACN: 9610170276 Fiche: 90420:334-90420:348

October 09, 1996	NRC notification (from S. Flanders) of October 16, 1996 meeting with BGE to discuss license renewal activities for cables. ACN: 9610150271	Fiche: 90403:360-90403:361
October 02, 1996	NRC notification (from S. Flanders) of October 10, 1996 meeting with BGE for the utility to present examples, prepared using template, on scoping/intended functions. ACN: 96100040037	Fiche: 89926:176-89926:177
September 24, 1996	Meeting summary (from S. Flanders) of November 11, 1996 meeting to discuss results of first phase of two phase review for five integrated plant assessment systems and commodity reports. ACN: 9609260016	Fiche: 89782:079-89782:119
September 23, 1996	NRC letter (from T. Martin) responding to May 22, 1996 BGE Integrated Plant Assessment Systems and Commodity Reports for staff review. Review completed in areas of scoping, intended functions, and aging effects. ACN: 9609250272	Fiche: 89775:352-2357
September 23, 1996	Meeting summary (from S. Flanders) of August 30, 1996 meeting with BGE regarding license renewal activities. ACN: 9609250348	Fiche: 89775:029-89775:063
September 23, 1996	Meeting summary (from R. Anand) of September 23, 1996 meeting with BGE regarding clarification of request for additional information. ACN: 9609250338	Fiche: 89773:355-89773:359
September 17, 1996	NRC notification (from S. Flanders) of September 20, 1996 meeting with BGE to develop scope and schedule for 90 day review effort proposed at September 11, 1996 meeting. ACN: 9609190204	Fiche: 89719-357:89719:359
September 06, 1996	NRC notification (from S. Flanders) of rescheduled September 11, 1996 meeting with BGE to discuss ongoing NRC review of BGE integrated plant assessment system and commodity report. ACN: 9609100470	Fiche: 89615-310:89615:311
September 03, 1996	NRC notification (from S. Flanders) of September 05, 1996 meeting with BGE to provide clarification of information requested by staff on August 30, 1996. ACN: 9609090261	Fiche: 89576-353:89576:355
August 30, 1996	NRC letter (from S. Flanders) forwarding requests for additional information regarding BGE's May 22, 1996 Integrated Plant Assessment Systems and Commodity report. Requests response within 60 days. ACN: 9609090388	Fiche: 89608:082-89608:123

August 23, 1996	NRC notification (from S. Flanders) of rescheduled September 11, 1996 meeting with BGE to discuss ongoing NRC review of BGE integrated plant assessment systems and commodity reports. ACN: 9608270072 Fiche: 89512-357:89512:359
August 22, 1996	NRC notification (from S. Flanders) of August 30, 1996 meeting with BGE to discuss issues associated with BGE license renewal template development. ACN: 9608230211 Fiche: 89451:356-89451:357
August 14, 1996	Meeting summary (from S. Flanders) of July 18, 1996 meeting with BGE to provide comments to BGE on revision of Main Feedwater and Structures Integrated Plant Assessment reports. ACN: 9608160168 Fiche: 89364:145-89364:149
August 02, 1996	Letter (from S. Newberry) informing BGE of staff review of July 03, 1996 letter requesting that no Part 170 fees be assessed for review of plant specific Systems and Commodity reports necessary for eventual license renewal application. ACN: 9608070213 Fiche: 89285:331-89285:333
August 01, 1996	NRC notification (from S. Flanders) of August 08, 1996 meeting with BGE to discuss BGE's integrated plant assessment system and commodity reports template. ACN: 9608050095 Fiche: 89252:294-89252:295
July 29, 1996	NRC notification (from S. Flanders) of August 30, 1996 meeting with BGE to discuss ongoing NRC review of BGE's Integrated Plant Assessment System and Commodity reports. ACN: 9607310147 Fiche: 89191:358-89191:359
July 25, 1996	BGE report containing portions of "Diesel Fuel Oil System License Renewal Technical Report" written for license renewal technical report template Phase 2 development. ACN: 9608190238 Fiche: 89388:329-89388:345
July 25, 1996	BGE report containing portions of "Component Supports License Renewal Technical Report" written for license renewal technical report template Phase 2 development. ACN: 9608190233 Fiche: 89388:308-89388:328
July 25, 1996	BGE report containing portions of "Structures License Renewal Technical Report" written for license renewal technical report template Phase 2 development. ACN: 9608190230 Fiche: 89388:288-89388:307

July 25, 1996	BGE report containing entire of "Feedwater System License Renewal Technical Report" written for license renewal technical report template Phase 2 development. ACN: 9608190228	Fiche: 89388:277-89388:287
July 25, 1996	BGE report containing draft of "Template of License Renewal Technical Report." ACN: 9608190223	Fiche: 89388:270-89388:276
July 12, 1996	Meeting summary (from S. Flanders) for June 20, 1996 meeting with BGE regarding aging management program and demonstration portion of Integrated Plant Assessment system and commodity reports template. ACN: 9607160268	Fiche: 89027:174-89027:225
July 12, 1996	NRC notification (from S. Flanders) of July 18, 1996 meeting with BGE to discuss BGE's integrated plant assessment system and commodity reports template. ACN: 9607170298	Fiche: 89040:250-89040:252
July 03, 1996	Meeting summary (from S. Flanders) for June 13, 1996 meeting with BGE regarding scope, intended functions and aging effects portion of Integrated Plant Assessment, commodity report template and demonstration. ACN: 9607090259	Fiche: 88950:149-88950:206
July 03, 1996	BGE letter (from C. Cruse) requesting that no fees be assessed for NRC review of listed portions of license renewal Integrated Plant Assessment system and commodity reports submitted. ACN: 9607100014	Fiche: 89254:201-89254:202
June 19, 1996	NRC notification (from S. Flanders) of July 20, 1996 meeting with BGE to discuss BGE's integrated plant assessment system and commodity reports template. ACN: 9606200316	Fiche: 88671:070-88671:072
June 05, 1996	Meeting summary (from S. Flanders) for May 22, 1996 meeting with BGE regarding status of BGE's license renewal efforts and NRC staff review of approach. ACN: 9606110362	Fiche: 88539:337-88539:360
June 05, 1996	Meeting summary (from S. Flanders) for May 30, 1996 meeting with BGE regarding discussion and development of schedule for first phase of review for five BGE integrated plant assessment system. ACN: 9606120138	Fiche: 88562:320-88562:353

June 04, 1996 — NRC notification (from S. Flanders) of July 13, 1996 meeting with BGE to discuss BGE's integrated plant assessment system and commodity reports template.
ACN: 9606060082 Fiche: 88464:340-88464:342

May 28, 1996 — NRC notification (from S. Flanders) of May 30, 1996 meeting with BGE to discuss technical reports and staff review approach.
ACN: 9605300174 Fiche: 88389:357-88389:359

May 22, 1996 — BGE letter (from C. Cruse) forwarding the first five Integrated Plant Assessment (IPA) system and commodity reports for review and approval in accordance with 10 CFR54, License Renewal Rule.
ACN: 9605240101 Fiche: 88363:001-88366:340

May 21, 1996 — BGE report (from B. Tilden) containing Revision 2 to "Aging Management Review Report for Component Supports."
ACN: 9605240134 Fiche: 88363:123-88363:206

May 21, 1996 — BGE report (from R. Tucker) containing Revision 2 to "Aging Management Review Report for Auxiliary Building, Final Report."
ACN: 9605240123 Fiche: 88363:207-8363:359

May 21, 1996 — BGE report (from D. Scoggin) containing Revision 1 to "Aging Management Review Report for RMS (077/079)."
ACN: 9605240109 Fiche: 88366:028-88366:237

May 20, 1996 — BGE report (from B. Tilden) containing Revision 3 to "Aging Management Review Report for Containment Structure (System 059), final report."
ACN: 9605240124 Fiche: 88364:001-88364:143

May 20, 1996 — BGE report (from R. Tucker) containing Revision 2 to "Aging Management Review Report for Intake Structure, Final Report."
ACN: 9605240121 Fiche: 88364:266-8365:043

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ACN: 9605240119 Fiche: 88364:144-88364:265

May 20, 1996 — BGE report (from R. Tucker) containing Revision 2 to "Aging Management Review Report for Fuel Oil Storage Tank 21 Enclosure, Final Report."
ACN: 9605240115 Fiche: 88365:044-88365:157

May 20, 1996 — BGE report (from R. Tucker) containing Revision 2 to "Aging Management Review Report for Condensate Storage Tank 12 Enclosure, Final Report."
ACN: 9605240111 Fiche: 88365:158-88365:278

May 09, 1996 — BGE report (from B. Tilden) containing Revision 1 to "Aging Management Review Report for Containment System (059)."
ACN: 9605240129 Fiche: 88363:058-88363:122

May 09, 1996	NRC notification (from S. Flanders) of May 22, 1996 meeting with BGE to discuss NRC review schedule and approach for BGE topical (system) reports and other license renewal issues. ACN: 9605140346 Fiche: 88278:111-88278:113
May 01, 1996	BGE report (from M. Hotchkiss) containing revision 1 to "Aging Management Review Report for Main Feedwater System." ACN: 9605240110 Fiche: 88365:279-88366:027
May 01, 1996	BGE report (from T. Hatch) containing Revision 1 to "Aging Management Review Report for Diesel Fuel Oil System (023)." ACN: 9605240108 Fiche: 88366:238-88366:340
April 15, 1996	NRC letter (from S. Newberry) submitting report on site visit to Calvert Cliffs on March 25 through 29, 1996, to review implementation of NEI 95-10, Revision 0, "Industry Guideline for Implementing Requirements of 10 CFR54, License Renewal Rule." ACN: 9604180250 Fiche: 87914:113-87914:146
April 09, 1996	NRC notification (from R. Prato) of April 15, 1996 meeting with Nuclear Energy Institute to discuss license renewal demonstration program. ACN: 9604180250 Fiche: 87914:113-87914:146
April 04, 1996	NRC report of Final Safety Evaluation regarding BGE's "Methodology for Meeting Requirements of 10 CFR54." ACN: 9604090438 Fiche: 87800:276-87800:306
April 04, 1996	NRC letter (from D. Crutchfield) forwarding Final Safety Evaluation and informing BGE that methodology acceptable for 10 CFR54.21(a)(2) requirements. ACN: 9604090427 Fiche: 87800:273-87800:306
February 02, 1996	NRC letter (from D. Crutchfield) forwarding draft safety evaluation regarding BGE's "Integrated Plant Assessment Methodology." ACN: 9602090213 Fiche: 87066:289-87066:323
January 11, 1996	BGE report containing "Calvert Cliffs Nuclear Power Plant Integrated Plant Assessment Methodology, Revision 1." ACN: 9601190247 Fiche: 86831:003-86831:082
January 11, 1996	BGE letter (from R. Denton) forwarding "Calvert Cliffs Nuclear Power Plant Integrated Plant Assessment Methodology, Revision 1." ACN: 9601190237 Fiche: 86831:001-86831:082

December 20, 1995	BGE letter (from R. Denton) forwarding proposed changes to "Calvert Cliffs Nuclear Power Plant Integrated Plant Assessment Methodology, " incorporating responses provided in August 15, 1995 letter as committed to in December 06, 1995 meeting. ACN: 9512280324 Fiche: 86662:189-86662:288
December 15, 1995	BGE letter (from R. Denton) forwarding response to NRC's request for additional information (November 16, 1995) regarding BGE report entitled "Integrated Plant Assessment Methodology (August 18, 19995)." ACN: 9512210261 Fiche: 86699:021-86600:234
December 12, 1995	Meeting summary (from J. Moulton) for December 06, 1995 meeting with BGE regarding proposed responses to requests for additional information resulting from ongoing review of Calvert Cliffs integrated plant assessment methodology. ACN: 9601020007 Fiche: 86682:005-86682:024
November 22, 1995	NRC notification (from J. Moulton) of December 06, 1995 meeting with BGE to discuss NRC request for additional information regarding license renewal integrated plant assessment methodology. ACN: 9511290078 Fiche: 86353:224-86353:225
November 16, 1995	NRC letter (from J. Moulton) requesting additional information regarding BGE report entitled, "Integrated Plant Assessment Methodology (August 18, 1995)." ACN: 9511200213 Fiche: 86280:124-86280:139
November 08, 1995	BGE letter (from R. Denton) forwarding schedule for submitting Integrated Plant Assessment system and commodity reports. ACN: 9511150186 Fiche: 86250:352-86250:354
August 18, 1995	BGE report containing Revision 0 to "Calvert Cliffs Nuclear Poser Plant Integrated Plant Assessment Methodology." ACN : 9508240149 Fiche: 85153:028-85153:165
August 18, 1995	BGE letter (from R. Denton) forwarding Revision 0 to "Calvert Cliffs Nuclear Poser Plant Integrated Plant Assessment Methodology." ACN : 9508240146 Fiche: 85153:026-85153:165
July 27, 1995	NCR notification revision (from S. Reynolds) for August 17, 1995 meeting with BGE to discuss BGE submittal plans for 1995 including BGE topical (system) reports. ACN: 9508040220 Fiche: 84940:040-84940:041
July 27, 1995	NCR notification (from S. Reynolds) for August 17, 1995 meeting with BGE to discuss BGE submittal plans for 1995 including BGE topical (system) reports. ACN: 9508010243 Fiche: 84888:001-84888:002

March 20, 1995	Meeting summary (from S. Hoffman) of March 08, 1995 meeting with BGE regarding BGE's License Renewal Program. ACN: 9503230310 Fiche: 83241:237-83241:307
March 03, 1994	NRC letter (from D. Crutchfield) forwarding draft safety evaluation report for BGE's report, "Integrated Plant Assessment Methodology Volume 1: Systems, Structures, & Components Screening." ACN: 9403280319 Fiche: 78673:301-78673:343
February 24, 1995	NRC notification (from S. Hoffman) of March 08, 1995 meeting with BGE to discuss the utility's approach to license renewal, 1995 plans and status, rulemaking issues and miscellaneous topics regarding BGE's license renewal program. ACN: 9503010174 Fiche: 82883:357-82883:358

APPENDIX B
REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Calvert Cliffs Nuclear Power Plant Units 1 and 2 under Docket Numbers 50-317 and 50-318.

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Charles H. Cruse, BGE to NRC, "Response to Request for Additional Information for the Review of the Calvert Cliffs Nuclear Power Plant, Units 1 and 2, Integrated Plant Assessment Reports for Component Supports and Piping Segments that provide Structural Support," dated November 19, 1998.

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____, Procedure MN-1-319 "Structure and System Walkdowns."

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____, "Quality Assurance Policy for the Calvert Cliffs Nuclear Power Plant," Revision 48.

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____, Calvert Cliffs Nuclear Power Plant, Aging Management Review of Component Supports," Revision 3, January 1997.

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APPENDIX C
ABBREVIATIONS

ABHVS	auxiliary building heating and ventilation system
ABSR&DBG	auxiliary building and safety-related diesel generator building
ACC	accumulator
ACI	American Concrete Institute
ADV	atmospheric dump valve
AFAS	auxiliary feedwater actuation system
AFS	auxiliary feedwater system
AFW	auxiliary feedwater
AFWAS	auxiliary feedwater actuation system
AISC	American Institute of Steel Construction
AMP	aging management program
AMR	aging management review
ANL	Argonne National Laboratory
ANSI	American National Standards Institute
AOR	analysis of record
ARDI	age-related degradation inspection
ARDM	age-related degradation mechanism
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
BACI	boric acid corrosion inspection program
BGE	Baltimore Gas and Electric Co.
B&PV	Boiler and Pressure Vessel Code (ASME)
BS	basket strainer
BTP	branch technical position
CAS	compressed air system
CASS	cast austenitic stainless steel
CBL	cable
CC	component cooling
CCNPP	Calvert Cliffs Nuclear Power Plant
CCS	component cooling system
CCW	component cooling water
CE	Combustion Engineering
CEA	control element assembly
CEASB	control element assembly shroud and bolts
CEDM	control element drive mechanism
CFR	*Code of Federal Regulations*

CI	confirmatory item
CI	containment isolation
CKV	check valve
CLB	current licensing basis
CRHVACS	control room heating, ventilation, and air conditioning system
CRS	cable and raceway system
CRVSP	comprehensive reactor vessel surveillancprogram
CS	containment spray
CSB	core support barrel
CSBA	core support barrel alignment
CSC	core support column
CSP	core support plate
CSS	containment spray system
CST	condensate storage tank
CSTR	core shroud tie rod
CUF	cumulative usage factor
CV	control valve
CVCS	chemical and volume control system
CWS	circulating water system
DBE	design-basis event
DFO	diesel fuel oil
DGBHVACS	diesel generator buildings heating, ventilation, and air conditioning system
EC	electrical commodity
ECCS	emergency core cooling system
ECE	electrical commodities evaluation
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full-power year
EFTS	equipment and floor drainage system [EFDS?]
EPDM	ethylene propylene diene monomer
EPM	electrical preventive maintenance
EPR	ethylene propylene rubber
EPRI	Electric Power Research Institute
EQ	environmental qualification
ERV	electronically operated relief valve
ESF	engineered safety features
ESG	extension shaft guide
ESFAS	engineer safety features actuation system
FAP	fuel alignment pin
FAHD	fuel assembly hold-down
FE	flow element
FEA	finite element analysis
FHA	fire hazards analysis
FHE	fuel handling equipment
FMP	fatigue monitoring program
FO	fuel orifice

FOST	fuel oil storage tank
FP	fire protection
FR	*Federal Register*
FSAR	final safety analysis report
FSE	final safety evaluation
FT	flow transmitter
FW	feedwater
FWS	feedwater system
GIP	generic implementation program
GL	generic letter
GSI	generic safety issue
HAZ	heat-affected zone
HDR	hold-down ring
HDSE	high-density silicon elastomer
HEPA	high-efficiency particulate air
HJTC	heated junction thermocouple
HLHC	heavy load handling cranes
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
H&V	heating and ventilation
HV	hand valve
HX	heat exchanger
IA	instrument air
IASCC	irradiation-assisted stress corrosion cracking
ICI	incore instrumentation
IGA	intergranular attack
IGSCC	intergranular stress corrosion cracking
ILCE	instrument line commodity evaluation
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
IR	issue report
IS	intake structure
ISI	inservice inspection
ISSGC	intake structure semi-gantry crane
IST	in-service testing
ITSP	incore instrumentation thimble support plate
LER	licensee event report
LG	level gauge
LIA	level indicator alarm
LLRT	local leak rate test
LOCA	loss-of-coolant accident
LPSI	low-pressure safety injection
LRA	license renewal application
LS	level switch

LSSBA	lower support structure beam assembly
MCC	motor control center
MIC	microbiologically induced corrosion
MFIV	main feedwater isolation valve
MFW	main feedwater
MOV	motor-operated valve
MS	main steam
MSIV	main steam isolation valve
MSSV	main steam safety valve
MTVEs	miscellaneous tank and valve enclosures
NACE	National Association of Corrosion Engineers
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NPRDS	Nuclear Plant Reliability Data System (INPO)
NRC	Nuclear Regulatory Commission
NSR	non-safety-related
NSSS	nuclear steam supply system
P&ID	piping and instrumentation diagram (in some places), drawing (in other places)
PA	plant air
PASS	post-accident sampling system
PB	pressure boundary
PC	polar crane
PCS	primary containment structure
PCSR	permanent cavity sealing ring
PCV	pressure control valve
PDI	pressure differential indicator
PEG	plant engineering guideline
PE-MCEU	principal engineer–maintenance component engineering unit
PEN	containment penetration assembly
PI	pressure indicator
PM	preventive maintenance
PNL	panel
PORV	power-operated relief valve
PS	pressure switch
PT	pressure/temperature
PT	pressure transmitter
PTS	pressurized thermal shock
PUMP	pump/driver assembly
PVC	polyvinyl chloride
PWR	pressurized water reactor
PWSCC	primary water stress corrosion cracking
PWST	page 2-13
PZV	pressure vessel

RAI	request for additional information
RAS	recirculation actuation signal
RC	reinforced concrete
RCP	reactor coolant pump
RCS	reactor coolant system
RI	core exit thermocouple system
RMS	radiation monitoring system
RP	recommended practice
RPS	reactor protective system
RPV	reactor pressure vessel
RRM	reactor refueling machine
RV	reactor vessel
RLV	relief valve
RVI	reactor vessel internals
RVIC	reactor vessel, reactor vessel internals, and reactor coolant (system)
RVLMS	reactor vessel level monitoring system
RWT	refueling water tank
RWTHX	refueling water tank heat exchanger
SA	saltwater air
S&Cs	structures and components
SACM	Societé Alsacienne de Constructions Mechaniques de Mullhouse
SBO	station blackout
SCC	stress corrosion cracking
SDC	shutdown cooling
SDCHX	shutdown cooling heat exchanger
SEAL	seal
SER	safety evaluation report
SFCHC	spent fuel cask handling crane
SFHM	spent fuel handling machine
SFP	spent fuel pool
SFPCS	spent fuel pool cooling system
SFSS	spent fuel storage system
SG	steam generator
SGBS	steam generator blowdown system
SI	safety injection
SIAS	safety injection actuation signal
SIT	safety injection tank
SOC	statement of considerations
SOV	solenoid-operated valve
SPCS	steam and power conversion system
SQUG	seismic qualification utility group
SR	safety-related
SR-DGB	safety-related diesel generator building
SRP-LR	standard review plan for license renewal
SRW	service water
SSC	systems, structures, and components
SSE	safe-shutdown earthquake

SSER	supplemental safety evaluation report
STP	surveillance test procedure
SV	solenoid valve
SVP	seismic verification program
SW	saltwater
SWA	saltwater air
SWAC	saltwater air compressor
SWS	saltwater system
TB	turbine building
TE	temperature element
TI	temperature indicator
TK	tank
TLAA	time-limited aging analysis
TMI	Three Mile Island
TP	test point
TS	technical specification
TSC	technical support center
TSP	trisodium phosphate
UFSA	updated final safety analysis report
UFSAR	updated final safety analysis report
UGS	upper guide structure
UGSP	upper guide structure support plate
UHS	ultimate heat sink
USAR	updated safety analysis report
USAS	United States of America Standards [I edited this out, but I don't know what you did.]
WOCT	waste oil collecting tank
WRNMS	junction box
XLPE	crosslinked polyethylene
XLPO	crosslinked polyolefin

APPENDIX D

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APPENDIX E
SIGNIFICANT PROGRAM FEATURES WARRANTING REGULATORY CONTROL

Appendix E presents a summary listing of the programs, maintenance activities and inspection procedures that formed a significant basis for the staff's conclusion. As such, this list represents those commitments that warrant regulatory control. BGE will incorporate appropriate changes to the next update of the final safety analysis report (FSAR), following the issuance of the renewed license. The FSAR will be updated for each item in Appendix E in accordance with the guidance for 10 CFR Section 50.71(e). Since future changes to the FSAR will be made in accordance with 10 CFR Section 50.59, these programs, maintenance activities and inspection procedures will be adequately controlled. Until the FSAR update is complete, a license condition requires that any changes to the items on the list be made in accordance with Section 50.59.

The listing in Appendix E also identifies future actions. Throughout this safety evaluation report, the staff has described various schedules for future actions. The staff has determined that none of the future actions are required prior to the end of the current license term in order to effectively manage aging. Therefore, as long as they are completed by the end of the current license term, licensee can make changes to such schedules without prior NRC approval. However, all of the future actions must be completed before the plant enters the period of extended operation, except for the volumetric inspections of the control element drive mechanisms in Unit 1 which will be completed by 2029 as described in Section 3.2.3.2.1.C (6) of the SER. Accordingly, the renewed license also includes a condition that all of the future actions must be completed by the end of the existing license term.

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
1.	3.1	Component Supports	Piping supports, cable raceway supports, heating, ventilation, and air conditioning (HVAC) ducting supports, equipment supports, frames and saddles (inside containment)/loss-of-coolant accident (LOCA) restraints	General Corrosion, Loading Due to Hydraulic Vibration or Water Hammer, Loading Due to Thermal Expansion, Stress Corrosion Cracking (SCC) of High Strength Bolts	Additional Baseline Walkdowns	Thirteen of the systems within the scope of license renewal that contain piping supports are not subject to American Society of Mechanical Engineers (ASME) Section XI inservice inspections (ISIs). Therefore, additional sampling baseline walkdowns will be performed. 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 aging effect 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. For component supports that were not covered or only partially covered by the baseline walkdowns 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 aging effects 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.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
2.	3.1	Component Supports	Piping supports, cable raceway supports, HVAC ducting supports, equipment supports, metal spring isolators and fixed bases (outside containment) /LOCA restraints, frames and saddles/LOCA restraints, frames and saddles/ring foundation for flat bottom vertical tanks (TKs), frames and saddles (inside containment) /LOCA restraints	General Corrosion, Loading Due to Hydraulic Vibration or Water Hammer, Loading Due to Thermal Expansion, Loading Due to Rotating or Reciprocating Equipment, SCC of High Strength Bolts	ISI of ASME Section XI Components (MN-3-110)	The Calvert Cliffs Nuclear Power Plant (CCNPP) ISI Program Plan describes the components to be examined, examination frequency, procedures, acceptance standards, and additional examinations. 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. 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 would detect the effects of aging-related degradation in a timely manner by examining the general mechanical and structural condition of components supports. The ASME Section XI ISI visual examination of the components determines the general mechanical and structural condition of the components and identifies potential degradation caused by aging. If any abnormal condition is identified, the ASME Code provides requirements for the timely correction of the condition.	Existing Program
3.	3.1	Component Supports	Elastomer vibration isolators	Elastomer Hardening	Plant Modification	The Seismic Verification Project 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 Seismic Verification Project walkdown, these supports were identified by the system engineer as requiring replacement, and a modification is planned to replace the elastomer isolators with spring-type isolators. After these isolators are replaced, follow-on inspections will be adequate to manage aging of elastomer vibration isolator component supports for other equipment.	Modification to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
4.	3.1	Component Supports	Cable raceway supports, HVAC ducting supports, equipment supports	General Corrosion	Preventive Maintenance (PM) Checklists	The CCNPP PM Program, MN-1-102, maintains 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 PM activities for nuclear power plant structures and equipment that are within the scope of license renewal. Some PM tasks (repetitive tasks) will be modified to look for the effects of specific aging mechanisms. These inspections will explicitly present inspection requirements for discovery of degraded coatings, material loss, or other indications of aging degradation. Repetitive tasks are automatically scheduled and implemented in accordance with PM Program procedures. Corrective actions are taken when degraded conditions are found during PM inspections. For components supports, the PM checklists (Mechanical Preventive Maintenance [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.	The program will be modified by midnight, July 31, 2014 (Unit 1) or midnight, August 13, 2016 (Unit 2).
5.	3.1	Component Supports	Piping supports	General Corrosion	PM Program (MN-1-102) • Repetitive Task 10672001	See a description of the PM Program in Section 3.1 above. Program for discovery of corrosion due to potential boric acid leakage for the piping supports associated with the spent fuel pool (SFP) demineralizer and filter.	The program will be modified by midnight, July 31, 2014 (Unit 1) or midnight, August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
6.	3.1	Component Supports	Piping supports	General Corrosion, Loading Due to Hydraulic Vibration or Water Hammer, Loading Due to Thermal Expansion	Snubber Visual Inspection Surveillances	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 that the snubber installation exhibits no signs of detachment from foundation or supporting structures, including clamps, welds, concrete anchor bolts, and general condition of concrete; and 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.	Existing Program

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
7.	3.1	Component Supports	Piping supports, cable raceway supports, HVAC ducting supports, equipment supports, elastomer vibration isolators, metal spring isolators and fixed bases (outside containment)/LOCA restraints, frames and saddles/LOCA restraints, frames and saddles/ring foundation for flat-bottom vertical TKs	General Corrosion, Loading Due to Hydraulic Vibration or Water Hammer, Loading Due to Thermal Expansion, Elastomer Hardening, Loading Due to Rotating or Reciprocating Equipment	Structure and System Walkdowns (MN-1-319) Control of Shift Activities (NO-1-200) Ownership of Plant Operating Spaces (NO-1-107)	Under MN-1-319, responsible personnel perform periodic walkdowns of their assigned structures and systems. Currently, structure walkdowns are performed during refueling outages. 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. The walkdown procedure provides specific guidance for identification of specific types of degradation or conditions when performing the walkdowns. The walkdowns will ensure that degraded conditions due to corrosion of steel are identified and corrected such that components will be capable of performing their intended functions under all current licensing basis (CLB) conditions. Control of Shift Activities (NO-1-200) is described in Section 6.4, below. Ownership of Plant Operating Spaces (NO-1-107) is described in Section 6.4, below.	Existing Program

Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
8.	3.2	Cranes, Reactor Vessel Cooling Shroud	Reactor vessel cooling shroud structural support members	Corrosion Due to Boric Acid	Boric Acid Inspection Program (BACI) Program (MN-3-301)	The BACI is credited for discovery and management of general corrosion/oxidation and corrosion due to boric acid for the reactor vessel cooling shroud structural support members by performing visual inspections. This program requires visual inspection and investigation of any leakage or corrosion that is found. A visual examination of external surfaces is performed for components in a borated water system, including the reactor vessel head penetrations. This program will be modified to specify examinations during refueling outages of: (a) the reactor vessel cooling shroud anchorage to the reactor vessel head for evidence of boric acid leakage; and (b) all reactor vessel cooling shroud structural support members for general corrosion/oxidation. The scope of the program is threefold in that it: (a) identifies locations to be examined; (b) provides examination requirements and procedures for the detection of leaks; and (c) provides the responsibilities for initiating engineering evaluations and the necessary corrective actions. The examinations will be performed each refueling outage using qualified inspectors and inspection techniques.	The program will be modified by midnight, July 31, 2014 (Unit 1) or midnight, August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
9.	3.2	Fuel Handling, Cranes	Carbon steel wire rope Carbon steel fuel handling equipment and heavy load handling crane (HLHC) components	Fatigue, Wear, Mechanical Degradation General Corrosion	Load Handling Procedure (MN-1-104)	For activities involving load handling at CCNPP, 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. The wire rope inspections specified in this procedure and implemented through the PM Program 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). All inspections are performed by qualified personnel trained to American National Standards Institute (ANSI) requirements. 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. The procedures in effect at CCNPP comply with NUREG-0612 and the applicable ANSI standards for control of heavy loads.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
10.	3.2	Fuel Handling	Stainless steel wire rope	Fatigue, Wear, Mechanical Degradation	Operating Instructions and Operations Section Performance Evaluations, as applicable Spent Fuel Handling Machine (SFHM) Procedures (OI-25A and PE 0-81-1-O-Q) Fuel Elevators Procedures (OI-25B and PE 0-81-3-O-Q) Refueling Machine Procedures (OI-25C and PE 0-81-2-O-C) Fuel Transfer System Procedure (OI-25E)	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. The Performance Evaluation Program provides for wire rope inspection for the SFHM, reactor refueling machine (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. PE 0-81-1-O-Q directs performance of OI-25A, which requires visual inspection of the hoisting rope while running the hoist through the full length of travel. PE 0-81-2-O-C directs performance of OI-25C, which requires the same activities for the main hoist on each unit's RRM. Visual inspection for damage to hoisting ropes in accordance with OI-25B is directed by PE 0-81-3-O-Q for the spent fuel inspection elevator and the new fuel elevator.	Existing Program

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
11.	3.2	Fuel Handling	Carbon steel components of the SFHM and the RRM	General Corrosion	Operations Section Performance Evaluations and associated Operating Instructions SFHM Procedures (PE 0-81-1-O-Q and OI-25A) Refueling Machine Procedures (PE 0-81-2-O-C and OI-25C)	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). PE 0-81-1-O-Q directs performance of OI-25A, 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. PE 0-81-2-O-C directs performance of OI-25C, which requires the same activities for each unit's RRM. 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 Baltimore Gas and Electric Company (BGE) personnel for monitoring these programs through periodic audits. These controls provide reasonable assurance that the associated activities will continue to be an effective means of monitoring the fuel handling equipment for the effects of general corrosion/oxidation.	Existing Program
12.	3.2	Cranes	Polar crane (PC) rails	Fatigue	Repetitive Task Perform NDE on PC Rails (10992001 (20992000)	See Section 3.1 for a description of the PM Program.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
13.	3.2	Fuel Handling, Cranes, Reactor Coolant (RCS)	Carbon steel parts of spent fuel cask handling crane (SFCHC), PC, intake structure semi-gantry crane (ISSGC), purge valve exhaust monorail hoist, and reactor vessel head lift rig	General Corrosion	Repetitive Tasks (modified to explicitly present inspection requirements): (00812007) (00812008) (00992015) (00992009) (10992010) (20992002) (10992007) (10992017) (20992011) (10642031) (20642030)	See Section 3.1 for a description of the PM Program. Credited for discovery and management of general corrosion effects in carbon steel parts of the Spent Fuel Inspection Elevator, New Fuel Elevator, transfer machine jib crane, SFCHC, PC, ISSGC, and reactor vessel head lift rig, respectively, by performing visual inspections.	The program will be modified by midnight, July 31, 2014 (Unit 1) or midnight, August 13, 2016 (Unit 2).
14.	3.2	Fuel Handling, Cranes	stainless steel and carbon steel wire rope and carbon steel chains	Fatigue, Wear, Mechanical Degradation	Repetitive Tasks: Inspect and Lubricate Fuel Transfer Cables, Winches, and Drivers (10812007, 20812009) Perform NDE on Fuel Handling Machine Crane Hook (10812013, 20812014) Inspect Auxiliary Building Cask Handling Crane (00992009) Lubricate Containment PCs (10992010, 20992002) Inspect Intake Structure Gantry Crane (10992007)	The CCNPP PM Program is described in Section 3.1. These PM repetitive tasks are for discovery and management of fatigue, wear, and mechanical degradation/ distortion effects in wire rope and wear of chains for the Fuel Upending Machines and Transfer Carriages, RRM main hoists, RRM auxiliary hoists, SFCHC, PCs, and ISSGC, respectively, by performing visual inspections. 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 a Load Handling Engineer.	Existing Program

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
15.	3.3A	Containment	Containment emergency sump cover and debris screen	General Corrosion	Containment Emergency Sump Inspection Procedures (STP-M-661-1 for Unit 1, and STP-M-661-2 for Unit 2)	The containment emergency sump cover and screen contains a wire mesh for trapping debris that could potentially be swept up by the safety injection (SI) 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), STP-M-661-1/2, "Containment Emergency Sump Inspection," 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.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
16.	3.3A	Containment	Containment tendons	Prestress Losses	Containment Tendon Procedures (STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2)	Procedure STP-M-663-1/2 provides instructions for the Containment Tendon Surveillance which includes: • 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. 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. 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. The existing tendon lift-off force curves will be re-evaluated to reflect the required prestress levels for the period of extended operation by monitoring the parameters specified in 10 CFR 50.55a(b)(2)(ix)(B), and applying the acceptance criteria for expected trends in prestressing forces and taking appropriate corrective action as specified in Section IWL of the ASME Code.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
17.	3.3A	Containment	Containment tendons	General Corrosion	Containment Tendon STPs (STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2)	The Containment Tendon STP is described in Section 3.3A above. These STPs discover and manage the effects of corrosion on the containment tendons by visual inspection and analysis of the filler grease.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
18.	3.3A	Containment	Grout under tendon bearing plates	Weathering	Containment Tendon Procedures (STP-M-663-1 for Unit 1 and STP-M-663-2 for Unit 2)	The Containment Tendon STP is described in Section 3.3A above. Program for discovery and management of the effects of weathering of grout by visual inspection.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
19.	3.3A	Containment	Containment liner	General Corrosion	Liner Plate Procedures (STP-M-665-1 for Unit 1 and STP-M-665-2 for Unit 2)	An examination of the containment liner plate is periodically performed in accordance with STP-M-665-1(2). 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. 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. 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.	Existing Program
20.	3.3A	Containment	Non-metallic portions of non-environmentally qualified (EQ) electrical penetrations	Radiation and Thermal Damage	Local Leak Rate Test (LLRT) Procedures (M-571J-1 and M-571K-1 for Unit 1 and M-571J-2 and M-571K-2 for Unit 2)	The LLRT is performed under STPs M-571J/K-1 and M-571J/K-2 as part of the overall CCNPP Containment Leakage Rate Testing Program. The CCNPP Containment Leakage Rate Testing Program implements 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 – Option B" and CCNPP Technical Specifications 3.6.1.2, 4.6.1.2, and 6.5.6. Credited for discovery and management of radiation and thermal damage for non-metallic portions of non-EQ electrical penetrations.	Existing Program

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21.	3.3A	Containment	Steel components inside the Containment Structure	General Corrosion	Painting and Other Protective Coatings (MN-3-100)	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, and ANSI N101.4 - 1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." MN-3-100 requires that the responsible engineer perform a walkdown of the inside of containment 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. 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 (ECCS). 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.	Existing Program
22.	3.3A	Containment	Emergency air lock gaskets	Permanent Set	PM Program (MN-1-102) (PAL-2)	PAL-2, Containment Personnel Emergency Escape Air Lock Adjustment, Lubrication, and Inspection, provides instructions for adjustment, lubrication, and inspection of the operating mechanism for the air lock. Degradation of the air lock gaskets is managed by replacement based on condition.	Existing Program
23.	3.3A	Containment	Embedded steel/rebar within the containment wall and dome	General Corrosion	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdowns Program is described in Section 3.1. Guidance will be added to assist in functional adequacy determinations and for authority to deviate from scope or schedule.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
24.	3.3A	Containment	Steel components outside the Containment Structure	General Corrosion	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdowns Program is described in Section 3.1. Guidance will be added to assist in functional adequacy determinations and for authority to deviate from scope or schedule.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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25.	3.3A	Containment	Refueling pool liner and permanent cavity seal ring (PCSR)	Intergranular stress corrosion cracking (IGSCC)	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdowns Program is described in Section 3.1. Guidance will be added to assist in functional adequacy determinations and for authority to deviate from scope or schedule.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
26.	3.3A	Containment	Dome	Commitment only; not credited for aging management	Evaluate Baseline Inspection results	Upcoming Baseline Inspections of Containment Structures will be used to verify that any freeze-thaw damage will not affect intended functions.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
27.	3.3B	Turbine Building	Caulking and sealants that do not function as fire barriers	Weathering	Caulking and Sealant Inspection Program	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 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.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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28.	3.3B	Turbine Building	Caulking and sealants that function as fire barriers	Weathering	Penetration Fire Barrier Inspection (STP-F-592-1/2)	The Penetration Fire Barrier Inspection STP-F-592-1/2 provides instructions for visual inspection of fire barrier penetration seals in fire area boundaries that protect safe shutdown areas. The scope of this procedure is to visually inspect the following type of fire barrier penetration seals for operability: • Electrical conduit and cable tray penetration seals; • HVAC duct penetration seals (ducts without dampers); and • Mechanical pipe and expansion joint penetration seals. 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. 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 Specifications. In addition, any conditions adverse to quality discovered during the inspection are documented on Issue Reports in accordance with the CCNPP Corrective Actions Program.	Existing Program
29.	3.3B	Turbine Building	Carbon steel components	General Corrosion	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdowns Program is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
30.	3.3C	Intake Structure	Caulking and sealants that do not function as fire barriers	Weathering	Caulking and Sealant Inspection Program	The Caulking and Sealant Inspection Program is described in Section 3.3B.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
31.	3.3C	Intake Structure	Caulking, sealants, and expansion joints that function as fire barriers	Weathering	Penetration Fire Barrier Inspection (STP-F-592-1/2)	The Penetration Fire Barrier Inspection is described in Section 3.3B.	Existing Program

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32.	3.3C	Intake Structure	Concrete of fluid-retaining walls and slabs	Aggressive Chemical Attack	PM Program (MN-1-102) 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	The PM Program is described in Section 3.1. • These PM tasks will be modified to include specific age-related degradation mechanisms (ARDMs) where they are not presently included and/or additional specified components/subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
33.	3.3C	Intake Structure	Embedded steel/rebar of fluid-retaining walls and slabs	General Corrosion	PM Program (MN-1-102) 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	The PM Program is described in Section 3.1. • These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
34.	3.3C	Intake Structure	Sluice gate wire rope and chain assemblies	Crevice Corrosion, Microbiologically-Induced Corrosion (MIC) and Pitting	Repetitive Tasks for Inspection of Sluice Gates	The PM Program is described in Section 3.1.	Modified or New Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
35.	3.3C	Intake Structure	Carbon steel components	General Corrosion	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdown is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
36.	3.3D	Miscellaneous Tank & Valve Enclosures	Carbon steel components	General Corrosion	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdown is described in Section 3.1. Program will be modified to specify scope and control of periodic structure performance assessments.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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37.	3.3E	Auxiliary Building and Safety-Related (SR) Station Blackout (SBO) Diesel Building	SFP liner	IGSCC	Nos. 11 & 12 SFPs - Determine Liner Leakage (Operations Section Performance Evaluation PE 0-67-2-O-M), and associated Spent Fuel Pool Cooling - Infrequent Operations, (Operating Instruction OI-24D)	The CCNPP Performance Evaluation Program provides for determination of SFP leakage. PE 0-67-2-O-M 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 Spent Fuel Pool Cooling (SFPC) 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. If the total leakage from all telltale valves exceeds one gallon in a 24-hour period, an engineering evaluation of the condition is performed.	Existing Program

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38.	3.3E	Auxiliary Building and SR/SBO Buildings	SFP storage racks	Loss of Neutron-Absorbing Material	Analysis of Neutron Absorbing Material in Spent Fuel Storage Racks, (Engineering Test Procedure 86-03R)	ETP 86-03R was developed on the basis of vendor recommendations for detecting degradation of neutron-absorbing materials. 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. 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. Unacceptable results are documented, reported, and corrected in accordance with the CCNPP Corrective Actions Program. 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. The program 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.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
39.	3.3E	Auxiliary Building and SR/SBO Buildings	Caulking, sealants, and expansion joints that do not function as fire barriers	Weathering	Caulking and Sealant Inspection Program	The Caulking and Sealants Inspection Program is described in Section 3.3B.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
40.	3.3E	Auxiliary Building and SR/SBO Buildings	Caulking, sealants, and expansion joints that function as fire barriers	Weathering	Penetration Fire Barrier Inspection (STP-F-592-1/2)	The Penetration Fire Barrier Inspection Program is described in Section 3.3B.	Existing Program

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41.	3.3E	Auxiliary Building and SR/SBO Buildings	Carbon steel components	General Corrosion	Structure and System Walkdowns (MN-1-319) Specify scope and control of periodic structure performance assessments	The Structure and System Walkdown is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
42.	4.1	RCS	PUMP	Erosion	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
43.	4.1	RCS	HV	Galvanic Corrosion	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
44.	4.1	RCS	PP, CKV, ERV, MOV, PUMP, steam generator (SG) HX, PZV, RV	General Corrosion	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
45.	4.1	RCS	PP, CV, ERV, HV, PUMP and MOV	Wear	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
46.	4.1	RCS	PP, PUMP and PZV (surge nozzle safe end)	Thermal Embrittlement	Cast Austenitic Stainless Steel (CASS) Evaluation Program	A new program will be developed to manage the effects of thermal embrittlement by identifying those components that may be susceptible to the effects of thermal embrittlement. The CASS Evaluation Program will: (1) screen components; (2) review operating experience; (3) utilize enhanced VT-1 inspection [a visual examination capable of ½ mil resolution] (for reactor vessel internals [RVI] only); and (4) follow industry programs to evaluate thermal embrittlement and change the program accordingly. Susceptibility of individual components to thermal embrittlement will be determined based upon the delta ferrite content of the component, the casting method (static or centrifugal), and the molybdenum content. When delta ferrite content is not documented for a component, it will be estimated using actual material data and Hull's equivalent factors. For components that fail the screening and are deemed susceptible to thermal aging embrittlement, the preferred alternative will be a flaw tolerance evaluation and augmented inspection. Fracture toughness properties used for the flaw tolerance evaluation will be estimated using the method in NUREG/CR-6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," and/or NUREG/CR-4513, Revision 1, "Estimation of Fracture Toughness of Cast Stainless Steels During Thermal Aging in LWR Systems." The intent of the analysis will be to determine if the respective component has adequate fracture toughness, based on its material properties, in order to be capable of performing its pressure boundary function under CLB conditions. A 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 by flaw tolerance analysis, or leak-before-break analysis, or if it is more cost effective to replace rather than perform an analysis. Replacement of the component will make the age-related degradation mechanism (ARDM) non-plausible for the respective component. The corrective actions taken as part of the CASS Evaluation Program will ensure that the CASS components remain capable of performing their pressure boundary function under all CLB	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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						conditions. If the components do not meet the screening criteria described above, then: 1. There will be an augmented inspection combined with a flaw tolerance evaluation; or 2. A full leak-before-break evaluation will be performed to prove that current inspection requirements are adequate to prevent catastrophic failure; or 3. They will be replaced. If an augmented inspection flaw tolerance approach is chosen, the acceptable flaw size for the inspection will be determined as follows: • For non-niobium containing components having less than 25% delta ferrite, a component specific J-R curve will be generated. If a component contains nobium or 25% or greater delta ferrite, the actual fracture toughness properties will be determined on a case-by-case basis. • An elastic-plastic fracture mechanics analysis will be performed for the component to determine the critical flaw size that is stable under all anticipated normal and accident loadings. This analysis may be component specific, or an analysis that bounds a group of components may be referenced. • The critical flaw size will be used to determine the inspection acceptance criteria. The critical flaw size minus an allowance for flaw growth during operation until the next inspection will equal the allowable flaw size. If available inspection technology permits, the inspection for RCS components will be conducted using a volumetric examination appropriate to a pressure-retaining weld on an ASME Section XI category B-L-1, B-M-1, or BJ component. If available inspection technology does not permit a volumetric examination, an alternative approach similar to that described in Code Case N-481 will be used.	Continued From Previous Page

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47.	4.1	RCS	PP, PZV, and SG HX	SCC/IGSCC and Primary Water Stress Corrosion Cracking (PWSCC)	CCNPP Alloy 600 Program	The Alloy 600 Program inspects RCS nozzles during each refueling outage for indications of leakage, through the performance of the BACI Program. 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 various factors. Some of the evaluation factors for PWSCC susceptibility include; operating temperature, material peak stress level, heat treatment, effective full power hours, and industry failures. 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. The Alloy 600 Program Plan includes specific provisions for monitoring industry experience and adjusting the plan accordingly. The program will be modified to include RCS nozzle thermal sleeves and non-pressure boundary components. Welds and base metals are implicitly included in this program.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
48.	4.1	RCS	SG HX	Denting, Wear, Pitting, SCC/IGSCC	Eddy Current Exam of CCNPP Unit 1 SG, and Eddy Current Exam of CCNPP Unit 2 SG (STP-M-574-1/2)	Both STP-M-574-1/2 are credited for discovering aging effects in SG heat exchanger (HX) tubes. The Unit 1 and 2 SG tubes are inspected during each unit's refueling outage. 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. An Issue Report is submitted to plug or sleeve SG HX tubes that are considered susceptible to failure before the next inspection. 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).	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
49.	4.1	RCS	SG HX tubes	Denting, Wear, Pitting, SCC/IGSCC	STP-O-27-1/2, RCS Leakage Evaluation	Calvert Cliffs procedures STP-O-27-1/2, "Reactor Coolant System Leakage Evaluation," are credited for discovering these ARDMs for the SG HX tubes. The procedure will discover these ARDMs by determining if any of the SG HX tubes 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 intended function. The CCNPP Technical Specifications provide the basis for the acceptance criteria of leakage rates.	Existing Program

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50.	4.1	RCS	PP, CKV, CV, ERV, SG HX, MOV, PUMP, PZV, and RV	Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	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 SR 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 historical records. 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 cumulative usage factor of less than or equal to one. The FMP tracks fatigue usage for the limiting components of the Nuclear Steam Supply System (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. A one-time fatigue analysis will be performed for the reactor coolant pumps (RCPs), motor-operated valves (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. The FMP will also assess the effect of the environment using statistical correlations developed by ANL in NUREG/CR-5704. The modified FMP will use the ANL statistical correlations to calculate an effective environmental factor to account for the reduction in fatigue life due to the reactor water environment. This factor will be applied to fatigue loads where the specified threshold criteria for strain rate and temperature have been exceeded. A factor of 1.5 will be used for evaluation of austenitic stainless steel components.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
51.	4.1	RCS	SG HX	Erosion Corrosion	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program

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52.	4.1	RCS	HV	Galvanic Corrosion	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
53.	4.1	RCS	PP, CKV, ERV, MOV, PUMP, SG HX, PZV, RV	General Corrosion	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
54.	4.1	RCS	PP, CV, ERV, HV, PUMP, and MOV	Wear	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
55.	4.1	RCS	PP	Commitment Only; not credited for aging management	Reactor Vessel Flange Protection Ring Removal and Closure Head Installation (CCNPP RV-78)	RV-78 prevents SCC on the reactor pressure vessel (RPV) head seal leakage detection line, making this ARDM not plausible. 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. Clearing the line of fluid eliminates the potential for this ARDM. This procedure will be performed after each refueling outage.	Existing Program

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56.	4.1	RCS	SG HX	Denting, Pitting and SCC/IGSCC	Specification and Surveillance for Secondary Chemistry (CP-217)	The scope of the Chemistry Program procedure CP-217, which controls Feedwater System (FWS) chemistry, includes the SGs, condensate storage tank (CST), feedwater, condensate, Main Steam System, heater drain tanks, condensate demineralizer effluent, SG blowdown ion exchanger effluent, and condensate precoat filters. The Chemistry Program controls fluid chemistry in order to minimize the concentration of corrosive impurities (chlorides, sulfates, oxygen) and optimizes fluid pH. Control of fluid chemistry minimizes the corrosive environment for FWS components, and limits the rate and effects of corrosion/pitting, denting and SCC/IGSCC. Secondary chemistry parameters (e.g., pH, dissolved oxygen levels) are measured at procedurally-specified frequencies. The measured parameter values are compared against target values that represent a goal or predetermined warning limit. If a measured value is out of bounds, corrective actions are taken (e.g., power reduction, plant shutdown) in accordance with the plant secondary chemistry procedure. Remedial actions are specified to minimize corrosion degradation of components and to ensure that secondary system integrity is maintained.	Existing Program
57.	4.1	RCS	SG tube supports	Erosion-Corrosion	Specification and Surveillance for Secondary Chemistry (CP-217)	See the description of CP-217 in Section 4.1 above.	Existing Program

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58.	4.1	RCS	RCP tube-in-tube seal water HX	Intergranular Attack (IGA)	Specification and Surveillance Primary Systems (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. 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 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.	Existing Program
59.	4.1	RCS	PP	SCC/IGSCC	Specification and Surveillance Primary Systems (CP-204)	The Chemistry Procedure CP-204 is described in Section 4.1 above.	Existing Program
60.	4.1	RCS	SG HX	SCC/IGSCC and PWSCC	Specification and Surveillance Primary Systems (CP-204)	The Chemistry Procedure CP-204 is described in Section 4.1 above.	Existing Program

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61.	4.1	RCS	RCP tube-in-tube seal water HX	IGA	Specifications and Surveillance for Component Cooling (CC)/Service Water (SRW) System (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. 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). All of the parameters listed in CP-206 currently have target values that give an acceptable range or limit for the associated parameter.	Existing Program
62.	4.1	RCS	Small bore piping	Fatigue	Age-Related Degradation Inspection (ARDI)	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; • Process for interpretation of examination results; • Process 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. Any abnormal conditions will be addressed by the CCNPP Corrective Actions Program.	ARDI will be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license).

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63.	4.1	RCS	SG tube supports	Erosion-Corrosion	SG Tube Surveillance Program (EN-4-106)	EN-4-106 is credited with discovering erosion-corrosion of the SG tube supports. The procedure allows for the inspectors to use the latest examination techniques to determine if there is any degradation to the SG tubes or tube supports. Remote visual inspections are conducted by lowering a video probe along the periphery of the tube bundle. The results of the inspection are evaluated using a fixed grading criterion. Eggcrate lattice bar structures are graded based on the most severe degradation viewed over the length of each lattice bar between and including the adjacent intersections. Categories currently in use for the inspection and grading criterion are described below: • Category A – Eggcrate lattice bar is in near new condition. This is characterized by a square edged or near square edged lattice bar or minimal thinning over the length of the lattice bar. • Category B – Eggcrate lattice bar is clearly thinned, but more than 50% of the bar remains in place over the length of the lattice bar between and at the intersection with adjacent lattice bars. • Category C – Greater than 10%, but less than 50% of the lattice bar remains over the length of the lattice bar between and at the intersection with adjacent lattice bars. • Category D – Less than 10% of the lattice bar remains over the length of the lattice bar or parts of the lattice bar is completely degraded so that no bar remains at a location between adjacent lattice bar intersections or at the would-be intersections. If two or more of the lattice bars at a single tube location are graded as Category D, then the eggcrate is deemed to be inactive at that tube. Unit 1 was inspected in 1996 and 1998; no eggcrate erosion was found. Unit 2 was inspected in 1999 and marginal, localized eggcrate lattice bar erosion was found.	Existing Program

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
64.	4.1	RCS	RCP tube-in-tube seal water HX	Wear	Use of Operating Experience and the Nuclear Hotline (NS-1-100)	Calvert Cliffs will continually review industry activity and experience with respect to wear of tube in tube RCP seal water HXs in accordance with CCNPP Administrative Procedure NS-1-100, "Use of Operating Experience." Calvert Cliffs will take appropriate actions if any wear-induced pressure boundary leakage occurs in RCP seal water HXs.	Existing Program
65.	4.2	RPVs and Control Element Drive Mechanisms (CEDMs)/ Electrical	RPV Alloy 600 components	SCC	Alloy 600 Program	The Alloy 600 Program is described in Section 4.1. The Alloy 600 Program will be modified to include all Alloy-600 components, not just those forming the pressure boundary.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2). Volumetric inspections of the CEDM nozzles will occur no later than 2029 for Unit 1.
66.	4.2	RPVs and CEDMs/ Electrical	RPV head and vessel	General Corrosion	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
67.	4.2	RPVs and CEDMs/ Electrical	RPV Alloy 600 nozzles	SCC	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
68.	4.2	RPVs and CEDMs/ Electrical	PZV (RPV), TP (Reactor Vessel Level Monitoring System [RVLMS]), CEDM	Wear	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
69.	4.2	RPVs and CEDMs/ Electrical	RPV	Neutron Embrittlement	CCNPP Comprehensive Reactor Vessel Surveillance Program (CRVSP)	The CCNPP surveillance program implements the requirements of 10 CFR Part 50, Appendix H, and provides the necessary data to monitor the embrittlement status of the reactor vessels. 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. 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 factors to identify and obtain test results and materials representative of the CCNPP RPVs from all available sources. These results to date demonstrate that CCNPP	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2). Unit 1 has two supplemental capsules that are designated for testing in 2000 and 2012. Continued From Previous Page

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						RPVs will remain well within established regulatory limits through the period of extended operation. In addition, BGE is participating in Combustion Engineering Owners Group (CEOG) programs targeted toward improving the accuracy of current processes and industry standards for determining the resistance of RPV materials to initiation and propagation of cracks (fracture toughness). The regulations already require embrittlement and loss of upper shelf energy 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. Baltimore Gas and Electric Company will continue to make periodic adjustments of neutron embrittlement and loss of upper shelf energy predictions, as needed, to account for any new information on the RPV beltline materials. In addition, BGE will make the following modifications to the CRVSP: 1. The capsule withdrawal schedule will be revised to provide data at neutron fluences equal to or greater than the projected peak neutron fluence at the end of the period of extended operation. 2. If the last capsule is withdrawn before the 55^{th} year, BGE will establish reactor vessel neutron environment conditions (fluence, spectrum, temperature, and neutron flux) applicable to the surveillance data and the Unit's pressure-temperature curves. If the plant operates outside the limits established by these conditions, the applicant must inform the NRC and determine the impact of the condition on RPV integrity. 3. If the last capsule is withdrawn before the 55^{th} year, BGE will install neutron dosimetry to permit tracking of the fluence to the RPV. Therefore, there is reasonable assurance that the affects of neutron irradiation on the CCNPP RPVs will be managed.	
70.	4.2	RPVs and CEDMs/ Electrical	Incore Instrument (ICI) tube nozzle flanges and associated components	Wear	ICI Flange Cleaning and Inspection (RV-85)	RV-85 is credited for the discovery of wear.	Existing Program

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71.	4.2	RPVs and CEDMs/ Electrical	PZV (RPV), CEDM, TP (RVLMS)	Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	The FMP is described in Section 4.1. The FMP will be modified to perform an engineering evaluation for CEDM/RVLMS components to ensure that the components are bounded.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
72.	4.2	RPVs and CEDMs/ Electrical	RPV components susceptible to general corrosion	General Corrosion	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
73.	4.2	RPVs and CEDMs/ Electrical	RPV anchor bolts	SCC	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
74.	4.2	RPVs and CEDMs/ Electrical	RPV components susceptible to mechanical wear	Wear	ISI of ASME Section XI Components (MN-3-110)	The ISI Program is described in Section 3.1.	Existing Program
75.	4.2	RPVs and CEDMs/ Electrical	RVLMS flanges and associated components	Wear	Installation of the Flexible Heated Junction Thermocouple in the Reactor (RVLMS-2)	RVLMS-2 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.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
76.	4.2	RPVs and CEDMs/ Electrical	RPV head and vessel	General Corrosion	RPV O-Ring Replacement (RV-22)	RV-22 is 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. Any evidence of general corrosion would be found during the performance of this procedure.	Existing Program
77.	4.2	RPVs and CEDMs/ Electrical	RPV, studs, nuts, and washers	General Corrosion, Wear	RPV, Stud, Nut, and Washer Cleaning (RV-62)	RV-62 is credited for the discovery of general corrosion and wear. 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.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
78.	4.3	RVI	CEASB (shroud bolts only)	Commitment Only; not credited for aging management	Analysis of CEA Shroud Bolts	BGE has determined that the control element assembly (CEA) shroud bolts are not required for the CEA shroud and fuel alignment pin (FAP) functions to be performed during normal and design basis event conditions. However, the boundary conditions for the CEA shrouds will change when all of the bolts are considered failed. This extreme assumption may result in changes in the natural frequency of CEA shrouds and could have an effect on the CEA shroud response. Also, because of the tight radial clearances between the CEA shroud flow channels and the precision machined holes in the FAP, BGE has determined that the conditions needed for unacceptable wear to occur at the interface between the FAP and CEA shrouds are not credible. The CEA shrouds and FAP will resist vertical and lateral operating and accident loads to the extent necessary for the CEAs to function as required and for adequate core cooling to be maintained. However, because of the potential to affect the CEA shroud frequency response with the extreme assumption that all of the CEA shroud bolts are failed, BGE will perform an analysis to confirm the above conclusions.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
79.	4.3	RVI	CEASB (shroud bolts only), CSTR (tie rods, nuts, and set screws only)	Stress Relaxation, SCC	ARDI Program	The ARDI Program is credited for 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.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
80.	4.3	RVI	CEASB (shroud assembly tubes only), CSC	Thermal Aging	Delta Ferrite Calculation for CASS Components	The delta ferrite content will be determined for CCNPP's RVI components made from CASS, and the results 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. 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. If the new calculations show that thermal aging is plausible, then these components would be managed by the CASS Evaluation Program. This program is described in Section 4.1.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
81.	4.3	RVI	CEASB (except spanner nuts, tabs, shroud bolts, retention blocks, and shaft retention pins)	High Cycle Fatigue	ISI of ASME Code Section XI Components, existing program implementing procedures (MN-3-110)	The ISI Program is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
82.	4.3	RVI	As applicable	Commitment only; not credited for aging management	ISI of ASME Code Section XI Components, existing program implementing procedures (MN-3-110)	Irradiation assisted stress corrosion cracking (IASCC) is considered not plausible for the RVI, however, BGE will continue to develop data through industry research to determine the susceptibility of RVI components to IASCC. Until the data and analyses become available confirming that IASCC should not be considered a plausible ARDM, BGE will perform enhanced VT-1 inspections to detect cracks (if any occur) in the RVI components believed to be potentially most susceptible to IASCC. The inspections will be performed as part of the 10-year ISI program during the license renewal term. (The ISI Program is described in Section 3.1.) Plant-specific justification will be provided to the NRC in the event the analyses and data support elimination of the inspection. Appropriate revisions to the ISI Program will be made to address the scope, methodology, detection, and acceptance criteria for these new inspections.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
83.	4.3	RVI	CEASB (except spanner nuts and tabs), CS, CSTR, CSB (except upper flange), CSC, CSP, FAP, Fuel Alignment Plate/Guide Lug Insert, LSSBA	Neutron Embrittlement	ISI of ASME Code Section XI Components, existing program implementing procedures (MN-3-110)	BGE will continue to develop data through industry research to determine the susceptibility of RVI components to neutron embrittlement. Until the data and analyses become available confirming that neutron embrittlement should not be considered a plausible ARDM, BGE will perform enhanced VT-1 inspections to detect cracks (if any occur) in the RVI components believed to be potentially most susceptible to neutron embrittlement. The inspections will be performed as part of the 10-year ISI program during the license renewal term. (The ISI Program is described in Section 3.1.) Plant-specific justification will be provided to the NRC in the event the analyses and data support elimination of the inspection. Appropriate revisions to the ISI Program will be made to address the scope, methodology, detection, and acceptance criteria for these new inspections	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
84.	4.3	RVI	ESG (guides only), CSB (upper flange only), CSBA, FAP, Fuel Alignment Plate/Guide Lug Insert (guide lugs and guide lug inserts only), HDR, UGSP	Wear	ISI of ASME Code Section XI Components, existing program implementing procedures (MN-3-110)	The ISI Program is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
85.	4.3	RVI	CS (plates and ribs only), CSTR (tie rods, nuts, and set screws only), CSC, CSP	Low Cycle Fatigue	Low-Cycle Fatigue Analysis of Components Subject to Gamma Heating	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. 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 Combustion Engineering plants. The fatigue critical components require further evaluation. The Code's fatigue design rules will be used to demonstrate that the effects of fatigue can be managed adequately for the RVI components. 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 operation. 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 FMP, or if not bounded, then the specific components will be added to the FMP.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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86.	4.3	RVI	CEASB (shroud bolts only), CSTR (tie rods, nuts, and set screws only)	Stress Relaxation	Stress Relaxation Analysis	Because the CEA shroud bolts and core shroud tie rod and bolts (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. 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. Combustion Engineering's evaluation for stress corrosion for all Combustion Engineering 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. 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. 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 ARDI Program. 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. 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 core shroud and, thus, are not accessible for visual examination.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
87.	5.1	Auxiliary Feedwater (AFW)	Class 'HB' PP	Crevice Corrosion General Corrosion MIC, Galvanic Corrosion and Pitting	AFW Buried Pipe Inspection Program	A new program for buried pipe will include AFW 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.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
88.	5.1	AFW	Class 'EB' PP	Cavitation Erosion	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
89.	5.1	AFW	CVs	Crevice Corrosion, General Corrosion, Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
90.	5.1	AFW	Class 'EB' and 'HB' PP, CKVs, CVs, HVs, and Turbines	Crevice Corrosion, General Corrosion, Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
91.	5.1	AFW	TK, PP, CKVs and HVs	Crevice Corrosion, General Corrosion, Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
92.	5.1	AFW	SVs	Elastomer Degradation and Wear	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

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93.	5.1	AFW	Pump Turbine	Crevice Corrosion, General Corrosion, Erosion Corrosion, Pitting	PM Program (MN-1-102) (Repetitive Tasks 10362000, 10362001, 20362018, 20362019) utilizing AFW Pump Turbine Overhaul (TURB-01) and AFW Pump Turbine Governor Valve Overhaul (VALVE-28)	The PM Program is described in Section 3.1. CCNPP Technical Procedure TURB-01, "Auxiliary Feedwater Pump Turbine Overhaul," disassembles the turbine to inspect 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.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
94.	5.1	AFW	CVOP	General Corrosion	PM Program (MN-1-102) Check Instrument Air (IA) Quality at System Low Points (Repetitive Tasks 10191024 and 20191022)	The PM Program is described in Section 3.1.	Existing Program
95.	5.1	AFW	CKVs	Crevice Corrosion General Corrosion Pitting	Specifications and Surveillance-Demineralized Water, SR Battery Water, Well Water Systems, and Acceptance Criteria for On-line Monitors (CP-202)	The CCNPP Demineralized Water Chemistry Specifications, CP-202, 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. 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. This program will mitigate the effects of crevice corrosion, general corrosion, and pitting of the internal surfaces of AFW System check valves (CKVs) located at the interface with the Chemical Addition System.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
96.	5.1	AFW	PP, CKVs, CVs, HVs, PUMP	Crevice Corrosion, General Corrosion, Pitting	Specifications and Surveillance: Secondary Chemistry (CP-217)	The Chemistry Procedure CP-217 is described in Section 4.1.	Existing Program
97.	5.1	AFW	Pump turbine	Crevice Corrosion, Pitting	Specifications and Surveillance: Secondary Chemistry (CP-217)	The Chemistry Procedure CP-217 is described in Section 4.1.	Existing Program
98.	5.1	AFW	Governor valve pump turbine CVs	Erosion Corrosion, Crevice Corrosion, General Corrosion, Pitting	Specifications and Surveillance: Secondary Chemistry (CP-217)	The Chemistry Procedure CP-217 is described in Section 4.1.	Existing Program
99.	5.1	AFW	Pump turbine	Crevice Corrosion, Pitting	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdown Program is described in Section 3.1.	Existing Program
100.	5.1	AFW	TK, PP, CKVs, HVs	Crevice Corrosion, General Corrosion, Pitting	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdown Program is described in Section 3.1.	Existing Program
101.	5.1	AFW	TK (No. 12 CST)	Elastomer Degradation	Structure and System Walkdowns (MN-1-319)	The Structure and System Walkdown Program is described in Section 3.1.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
102.	5.2	Chemical and Volume Control (CVCS)	Items with boric acid or borated water internal environments	Crevice Corrosion and Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
103.	5.2	CVCS	Letdown HX shell side	Crevice Corrosion and Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
104.	5.2	CVCS	CKVs and CVs	Wear	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
105.	5.2	CVCS	All items exposed to borated water (due to leakage)	General Corrosion	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program

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106.	5.2	CVCS	CVOPs and PCVs with air internal environment	General Corrosion	Check Unit 1(2) IA Quality (IPM 10000 [10001])	The quality of IA System components that are within scope is verified approximately quarterly, based on operating experience and applicable industry standards, in accordance with Checklist IPM10000 and IPM 10001. These checklists assure that the system is being maintained in accordance with industry standards for moisture (dewpoint) and particulate contamination. This procedure is used to mitigate the effects of general corrosion on control valve operators and pressure control valves.	Existing Program
107.	5.2	CVCS	Letdown Line piping, CKVs, CVs, HXs, HVs and TEs	Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	The FMP is described in Section 4.1.	Existing Program
108.	5.2	CVCS	CKVs and CVs	Wear	LLRT, Penetrations 1A, 1B, 1C (M-571A-1[2]) LLRT, Penetrations 2A, 2B (M-571C-1[2])	The LLRT is described in Section 3.3A.	Existing Program
109.	5.2	CVCS	Heat traced PP and components	SCC	Plant Modification to replace heat tracing	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.	Existing Program
110.	5.2	CVCS	Letdown HX shell side	Crevice Corrosion and Pitting	Specification and Surveillance CC/SRW System (CP-206)	The CP-206 is described in Section 4.1.	Existing Program
111.	5.2	CVCS	Items with boric acid or borated water internal environments	Crevice Corrosion and Pitting	Specification and Surveillance Primary Systems (CP-204)	The CP-204 is described in Section 4.1.	Existing Program
112.	5.3	CC	PP, automatic vents, CKVs, CVs, HVs, PUMP casings, REs, RVs, SVs, TEs, TIs, TICs, TKs	Crevice Corrosion, Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

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113.	5.3	CC	PP	Erosion Corrosion	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
114.	5.3	CC	PP, CKVs, CVs, HVs, PUMP casings, RVs, TEs, TIs, TKs	General Corrosion	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
115.	5.3	CC	Automatic vents, CVs, HVs, RVs, SVs	Selective Leaching	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
116.	5.3	CC	CKVs, CVs	Wear	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
117.	5.3	CC	PUMP casings	General Corrosion, Crevice Corrosion, Pitting	CC Pump Overhaul and Inspection (PUMP-14)	The CC pumps are inspected for crevice corrosion/ pitting and general corrosion using the PUMP-14 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. Previous CC pump overhauls at CCNPP did not reveal any problems associated with crevice corrosion/pitting, general corrosion, or any other corrosion mechanisms. Any corrective actions that are required will be taken in accordance with the CCNPP Corrective Actions Program, and will ensure that the components will remain capable of performing their intended function under all CLB conditions.	Existing Program
118.	5.3	CC	CVs	Rubber Degradation, Wear	LLRT, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64 (STP-M-571E-1[2])	The LLRT Program is described in Section 3.3A.	Existing Program
119.	5.3	CC	PP, automatic vents, CKVs, CVs, HVs, PUMP casings, REs, RVs, SVs, TEs, TIs, TICs, TKs	Crevice Corrosion, Pitting	Specification and Surveillance CC/SRW System (CP-206)	Procedure CP-206 is described in Section 4.1.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
120.	5.3	CC	PP, CKVs, CVs, HVs, PUMP casings, RVs, TEs, TIs, TKs	General Corrosion	Specification and Surveillance CC/SRW System (CP-206)	Procedure CP-206 is described in Section 4.1.	Existing Program
121.	5.3	CC	Automatic vents, CVs, HVs, RVs, SVs	Selective Leaching	Specification and Surveillance CC/SRW System (CP-206)	Procedure CP-206 is described in Section 4.1.	Existing Program
122.	5.4	Compressed Air	Containment Penetration portion of the Plant Air Subsystem	General Corrosion	ARDI Program	The ARDI Program is described in Section 4.1	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
123.	5.4	Compressed Air	CKV	Wear	CCNPP Pump and Valve Inservice Test (IST) Program STPs • M-583-1 • M-583-2	Leak rate testing of the CKVs providing SR-non-safety-related (NSR) pressure boundary portions of the system is performed 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). ASME XI, Subsection IWV, directs each licensee to comply with the applicable portions of ASME/ANSI OM-10. ASME/ANSI OM-10 provides the rules and requirements for IST of CCNPP valves, including the types of tests required, frequency of testing, test procedure, test pressures, acceptance criteria, and reporting requirements. The subject CKVs 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 STPs M-583-1 and M-583-2. The corrective actions taken as part of the Pump and Valve IST Program will ensure that the CKVs 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.	Existing Program
124.	5.4	Compressed Air	Containment Isolation Valves (CIVs) of the Plant Air Subsystem	General Corrosion	LLRT, Penetrations 19A (IA Service) 19B (Service Air) (STP-M-571F-1[2])	The LLRT Program is described in Section 3.3A.	Existing Program

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
125.	5.4	Compressed Air	CKVs, MOVs	Wear	LLRT, Penetrations 19A (IA) 19B (Service Air) (STP-M-571F-1[2])	The LLRT Program is described in Section 3.3A.	Existing Program
126.	5.4	Compressed Air	All Compressed Air System carbon steel components	General Corrosion	PM Program (MN-1-102) • 10191024 • 20191022	The PM Program is described in Section 3.1.	Existing Program
127.	5.5	Containment Isolation Group (CIG)	Components exposed to treated water or gaseous waste	Crevice Corrosion, General Corrosion and Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
128.	5.5	CIG	Components exposed to well water	Crevice Corrosion, General Corrosion, MIC, and Pitting	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
129.	5.5	CIG	CKVs, RVs, HVs	Wear	ARDI Program	The ARDI Program is described in Section 4.1.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
130.	5.5	CIG	MOVs in borated water systems	Crevice Corrosion, General Corrosion and Pitting	BACI Program (MN-3-301)	The BACI Program is described in Section 3.2.	Existing Program
131.	5.5	CIG	CIVs exposed to well water	Crevice Corrosion, General Corrosion, MIC, and Pitting	CCNPP Leakage Rate Testing Program: LLRT Procedures STP-M-571G-1(2) STP-M-571M-1(2)	See Section 3.3A for a discussion of the LLRT Program.	Existing Program
132.	5.5	CIG	CIVs	Wear	CCNPP Leakage Rate Testing Program: LLRT Procedures STP-M-571A-1(2) STP-M-571D-1(2) STP-M-571E-1(2) STP-M-571G-1(2) STP-M-571M-1(2)	See Section 3.3A for a discussion of the LLRT Program.	Existing Program

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
133.	5.5	CIG	CIVs exposed to treated water or gaseous waste	Crevice Corrosion, General Corrosion and Pitting	Leakage Rate Testing Program: LLRT Procedures STP-M-571A-1(2) STP-M-571D-1(2) STP-M-571E-1(2) STP-M-571G-1(2)	See Section 3.3A for a discussion of the LLRT Program.	Existing Program
134.	5.6	Containment Spray	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs	General Corrosion, Crevice Corrosion, and/or Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
135.	5.6	Containment Spray	PP, CKVs, CVs, HVs, HXs, MOVs, and PUMPs that are exposed to borated water (due to leakage)	General Corrosion	BACI Program (MN-3-301)	See Section 3.2 for a description of the BACI Program.	Existing Program
136.	5.6	Containment Spray	Shutdown cooling (SDC) HXs	General Corrosion, Crevice Corrosion, and/or Pitting	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
137.	5.6	Containment Spray	PP, CKVs, CVs, FEs, FOs, HVs, HXs, MOVs, PUMPs, RVs, TEs, and TIs) that are exposed to borated water (as process fluid)	General Corrosion, Crevice Corrosion, and/or Pitting	Specification and Surveillance Primary Systems (CP-204)	See Section 4.1 for a description of CP-204.	Existing Program
138.	5.7	Diesel Fuel Oil (DFO)	DFO TKs	Crevice Corrosion, General Corrosion, Pitting, Fouling, and MIC	Determination of Particulate Contamination in DFO (CP-973)	CP-973 provides instructions to quantify insoluble particulate contamination in diesel fuel. This procedure was developed based on industry standards including: • ASTM D-2276-89, Standard Test Method for Particulate Containment in Aviation Fuel; and • EPRI Guidelines: Storage and Handling of Fuel Oil for Standby Diesel Generator Systems, Revision 1. Under this procedure, the analytical data generated from the fuel oil sample is submitted to the Supervisor- Chemistry Environmental Services for review and approval. Diesel fuel in the tank is sampled and analyzed quarterly. Fuel oil is drawn from several levels of the tank for analysis.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
139.	5.7	DFO	DFO TKs	Crevice Corrosion, General Corrosion, Pitting, Fouling, and MIC	DFO Storage Tank Water Check (STP O-106-0)	Under STP O-106-0, water that may collect at the DFO tank bottom is periodically drained and fuel chemistry is analyzed. If the amount of drained water or fuel chemistry is found not to meet the established standards, corrective action is implemented as required. Draining the water will minimize the degradation of the internal surface of the carbon steel tank bottom, and will also minimize the possibility of MIC since microbes require water to survive and multiply. If more than one gallon of water is drained, the operator is required to notify the shift supervisor, and the situation will be investigated to determine and correct the source of the water	Existing Program
140.	5.7	DFO	Buried PP	Crevice Corrosion, General Corrosion, Galvanic Corrosion, MIC, and Pitting	DFO Buried Pipe Inspection Program	A new program for buried pipe inspection will include DFO and will provide assurance that the effects of aging are being effectively managed for the period of extended operation under CLB design loading conditions. This program will consider variations in environmental conditions (including cathodic protection) to select representative samples of the buried piping for inspection to ensure that the pipe coating/wrapping and cathodic protection system are adequately protecting the pipe from external ARDMs.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
141.	5.7	DFO	DFO Tanks	Crevice Corrosion, General Corrosion, Pitting, Fouling, and MIC	Oil Receipt Inspection and Fuel Oil Storage Tank (FOST) Surveillance (CP-226)	Fuel oil chemistry is controlled, under CP-226, including testing for the presence of biologics. The procedure establishes surveillance frequencies, fuel oil specifications (e.g., viscosity, % water and sediment, particulate contamination, and biologics), and corrective actions. Sampling and analysis are performed on new fuel prior to unloading from fuel trucks. This procedure specifies limits for viscosity, water, and sediment for both receipt inspection and Technical Specification surveillance, in accordance with ASTM D975-81. This procedure now requires the addition of a stabilizer/corrosion inhibitor prior to unloading fuel oil into the FOSTs. Prior to adoption of this new approach, the stabilizer/inhibitor was being added with initial tank fill, after being emptied for surveillance. The new approach provides a better assurance that the desired ratio of inhibitor to fuel oil exists. Corrosion inhibitor is added to the fuel to control corrosion of any exposed metal surfaces in the tank. A biocide is also added to the FOSTs for the initial addition, or if the presence of biological activity has been confirmed, to control MIC.	Existing Program
142.	5.7	DFO	All above-ground DFO items	Crevice Corrosion, General Corrosion, and Pitting	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Existing Program
143.	5.7	DFO	DFO TKs	Weathering	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
144.	5.7	DFO	DFO TKs	Crevice Corrosion, General Corrosion, Pitting, Fouling, and MIC	Tank Internal Inspection Program	Draining water and chemistry testing/control of fuel oil provide a high degree of confidence that the effects of the plausible ARDMs will be minimized. However, the internal surfaces of the tank are not accessible during system walkdowns; therefore, a new Tank Internal Inspection Program is intended to provide assurance that the effects of plausible aging are being effectively managed. Under this program, BGE will perform an internal inspection of the FOSTs at periodic intervals based on results of previous inspections. If degradation mechanisms are found, corrective actions will be implemented. Future inspections may be scheduled, if appropriate. This inspection includes the following features: • A visual assessment of the condition of the tank interior in accordance with American Petroleum Institute Standard 653 for FOST inspections; • Measurements of the thickness of the tank interior coating at several locations in the tank, in accordance with ASTM D-1186 for coating thickness measurements; and • Observations for voids and pinholes in the tank coating, in accordance with guidance provided in the recommended practice NACE RP0188, "Discontinuity (Holiday) Testing of Protective Coating." The results of this inspection will be documented and used to assess the overall condition of the tank and the appropriate interval until the next inspection. A PM Repetitive Task will be developed to initiate and track the inspection requirements.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
145.	5.8	Emergency Diesel Generator (EDG)	EDG cooling water piping	Erosion Corrosion	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
146.	5.8	EDG	EDG exhaust mufflers	Erosion Corrosion, Particulate Wear Erosion	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
147.	5.8	EDG	EDG exhaust piping and exhaust mufflers	Fatigue	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
148.	5.8	EDG	EDG starting ACCs, jacket water expansion TKs, DFO day TKs, and drip TKs with their associated TK level switches, HVs, drain traps, exhaust piping and mufflers, and cooling water piping	General Corrosion, Crevice Corrosion, and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
149.	5.8	EDG	EDG fuel oil day TKs, drip TKs, and their associated TK level switches	MIC	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
150.	5.8	EDG	EDG starting air (SA) drain traps	Wear	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
151.	5.8	EDG	Jacket water expansion TSs and cooling water PP	General Corrosion, Crevice Corrosion, and Pitting	CCNPP Specification and Surveillance Diesel Generators' Jacket Cooling System (CP-222)	CP-222 is credited with mitigating the effects of general corrosion, crevice corrosion, and pitting of the cooling water piping and jacket water expansion tanks by monitoring and maintaining EDG jacket water chemistry (e.g., pH, dissolved oxygen). This procedure contains two different sets of chemistry parameters, one for the Fairbanks Morse EDGs, and one for the SACM (Societe Alsacienne De Constructions Mecaniques De Mulhouse) EDG. The water is treated with hydrazine or corrosion inhibitors 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 mitigate EDG jacket water expansion tank and cooling water piping degradation. Procedure CP-222 provides for a prompt review of EDG jacket water chemistry parameters so that steps can be taken to return chemistry parameters to normal levels, and, thus, minimize the effects of general corrosion, crevice corrosion, and pitting.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
152.	5.8	EDG	EDG SA and combustion air (CA) intake piping	General Corrosion, Crevice Corrosion, and Pitting	Clean and Inspect EDG Air Start Distributor and CKVs (MPM13000)	MPM13000 is credited with the discovery of the degradation of internal piping surfaces for EDG SA, and CA intake systems. The MPM will be modified to inspect specifically for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1), or midnight August 13, 2016 (Unit 2)
153.	5.8	EDG	EDG lube oil "Y" strainers	General Corrosion, Crevice Corrosion, and Pitting	Clean/Inspect 2B, 1B, and 2A EDG Lube Oil "Y" Strainers and Baskets (MPM13003, MPM13004/MPM13005)	These checklists are credited with discovery of the effects of degradation on the "Y" strainer internal surfaces. The MPMs will be modified to check for signs of corrosion on the "Y" strainer internal surfaces.	Program to be modified by midnight July 31, 2014 (Unit 1), or midnight August 13, 2016 (Unit 2)
154.	5.8	EDG	EDG SA and CA intake piping and SA system CKVs	General Corrosion, Crevice Corrosion, and Pitting	Disassemble, Inspect and Overhaul EDG CKV (MPM07006)	MPM07006 is credited with discovery of the effects of pitting, crevice corrosion, and general corrosion of the internal surfaces of EDG SA System CKVs. This MPM will be modified to inspect specifically for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1), or midnight August 13, 2016 (Unit 2)
155.	5.8	EDG	EDG SA/CA intake piping, EDG intake filters and intake mufflers, and EDG intake filters	General Corrosion, Crevice Corrosion, and Pitting	Inspect EDG Air Intake Filters (MPM07117)	MPM07117 is credited for the discovery of effects of corrosion on the internal surfaces of the EDG SA/CA intake piping, internal surfaces of the EDG intake filters and intake mufflers, and external surfaces of the EDG intake filters. The MPM will be modified to inspect the attached piping for signs of corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
156.	5.8	EDG	EDG SA and CA intake PP	General Corrosion, Crevice Corrosion, and Pitting	Inspect EDG Air Start Valves and Filters (MPM13002)	MPM13002 is credited with the discovery of the effects of corrosion of internal piping surfaces for EDG SA, and CA intake systems. This MPM will be modified to inspect specifically for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
157.	5.8	EDG	EDG exhaust piping and mufflers	General Corrosion, Crevice Corrosion, Pitting, and Fatigue	Perform Visual Examination for EDG Exhaust Components (MPM13110)	MPM13110 is credited with the discovery of degradation of the EDG exhaust piping and exhaust muffler. This task requires examination for evidence of corrosion. The MPM will be modified to look for signs of fatigue on the external surfaces of the EDG exhaust piping and exhaust mufflers.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
158.	5.8	EDG	EDG SA and CA intake PP	General Corrosion, Crevice Corrosion, and Pitting	Remove Relief Valve, Test and Reinstall (MPM01125)	MPM01125 is credited with the discovery of degradation of the internal piping surfaces for EDG SA, and CA intake systems. This MPM will be modified to inspect specifically for corrosion of piping and check for the presence of debris in valves that could indicate the piping in these systems is undergoing corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
159.	5.8	EDG	DFO day TKs, drip TKs and associated level switches	General Corrosion, Crevice Corrosion, Pitting, and MIC	Specification and Surveillance - DFO (CP-226)	CP-226 is credited for mitigating the effects of crevice corrosion, general corrosion, MIC and pitting on the interior surfaces of the EDG DFO day tanks, and drip tanks with associated tank-mounted level switches. Under CP-226, fuel oil chemistry is controlled, including testing for the presence of biologics. The procedure establishes surveillance frequencies, fuel oil specifications (e.g., viscosity, % water and sediment, particulate contamination and biologics), and corrective actions. Sampling and analysis are performed on new fuel prior to unloading from fuel trucks. This procedure specifies limits for water, viscosity, and sediment for both receipt inspection and Technical Specification surveillance for fuel oil in the FOSTs in accordance with ASTM-D975-81. The procedure currently has target values and action levels that give an acceptable range or limit for a given parameter. This procedure now requires the addition of a stabilizer/corrosion inhibitor prior to unloading fuel oil into the FOSTs. Prior to adoption of this new approach, the stabilizer/inhibitor was added only once a year. The new approach provides a better assurance that the desired ratio of inhibitor to fuel oil exists. In August 1989, CP-226 was revised to incorporate criteria in accordance ASTM-D270-65 for taking quarterly samples from the diesel FOSTs. This revision involves taking multilevel samples from each diesel FOST rather than sampling only from the tank bottom, as was done previously.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
160.	5.8	EDG	DFO day TKs, drip TKs	General Corrosion, Crevice Corrosion, Pitting, and MIC	Testing EDGs and the 4 kV LOCA Sequencers (STP O-8A-2, STP O-8B-1, STP O-8B-2)	STP-O-8A-2, STP-O-8B-1, and STP-O-8B-2 are credited for mitigation of crevice corrosion, general corrosion, pitting, and MIC on the interior of the DFO day tanks. The procedures provide for periodic draining of DFO day tank of any water that may be present, which minimizes the corrosive effects of water on carbon steel. The tank sample is taken and visually examined for the presence of water in the fuel. This procedure is currently performed monthly after the EDGs are shut down from testing.	Existing Program
161.	5.9	FWS	MOVs and TEs	Erosion Corrosion	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
162.	5.9	FWS	PP, CKVs, HVs, MOVs and TEs	General Corrosion Crevice Corrosion and/or Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
163.	5.9	FWS	PP	Erosion Corrosion	Erosion/Corrosion Monitoring of Secondary Piping (MN-3-202)	The Erosion Corrosion Monitoring Program is intended to ensure nuclear and personnel safety by early identification and prevention of secondary pipe wall thinning caused by accelerated corrosion, cavitation, or erosion that could lead to ruptures in high energy piping. All of the FWS piping subject to aging management review, as well as all the piping in the system not subject to aging management review, are included in this program. All piping within the scope of the program is evaluated and categorized to determine inspection points where thickness measurements will be taken. Inspection points are determined through evaluations of site-specific data, failures at other plant sites, and modeling of piping systems by the CHECWORKS software developed by EPRI. An ultrasonic NDE is used to determine the wall thickness at a number of grid locations for each inspection point. These data are used with a predictive model to determine additional inspection points, to adjust an inspection point's priority, or to estimate the time remaining before an inspection point's wall thickness reaches the minimum allowable. The results are then analyzed to determine the need to replace components. Inspection data is tracked and extrapolated to estimate the time until the minimum wall thickness will be reached. When an inspection point is estimated to be within 48 to 72 months of the minimum wall thickness, it is placed on a "Yellow Alert." When an inspection point is estimated to be within 24 to 48 months of minimum wall thickness, it is placed on a "Red Alert." When an inspection point is estimated to be within 24 months of the required minimum thickness, it is classified as "Unsatisfactory." If any of the alert values are reached, corrective actions are initiated in accordance with the inspection procedure.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
164.	5.9	FWS	PP	Low Cycle Fatigue	Evaluation of the Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal	To fully address fatigue for license renewal, CCNPP has initiated an additional evaluation, in conjunction with EPRI, to evaluate the effects of low cycle fatigue on the FWS, the pressurizer surge line, and the charging/letdown lines. The evaluation will apply 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 evaluation objective includes the development and justification of aging management practices for fatigue at various component locations for the renewal period. Specifically for the FWS, the evaluation will: • identify those specific components that are considered fatigue sensitive; • utilize tracking data for the SG feedwater nozzle to determine if the anticipated fatigue usage is acceptable for license renewal and bounds the anticipated fatigue usage of the connected ANSI B31.1 piping; • assess the impact of environmental effects for those components that are projected to be bounded by the CLB through the period of license renewal; • perform an analysis using the methodology identified in the ASME Section XI non-mandatory Appendix L on fatigue evaluation for those components not bounded by the CLB through the period of license renewal; and • address the conclusions drawn in SECY-95-245 (completion of the Fatigue Action plan) with respect to components/locations considered in NUREG/CR-6260 relative to the issue of environmental effects.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
165.	5.9	FWS	PP	Low Cycle Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	See Section 4.1 for a description of the FMP.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
166.	5.9	FWS	CKVs	Erosion Corrosion	PM Program (MN-1-102)	See Section 3.1 for a description of the PM Program.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
167.	5.9	FWS	PP, CKVs, HVs, MOVs, and TEs	General Corrosion Crevice Corrosion and/or Pitting	Specifications and Surveillance - Secondary Systems (CP-0217)	See Section 3.2 for a description of CP-217.	Existing Program
168.	5.10	Fire Protection (FP)	Pipe, fittings, flanges, studs, and nuts	Crevice Corrosion General Corrosion Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
169.	5.10	FP	For FP, all NSR portions of the systems required for safe shutdown (Appendix R Fire Scenario) are included in the group	General Corrosion	BACI Program (MN-3-301)	See Section 3.2 for a description of the BACI Program.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
170.	5.10	FP	For FP, all NSR portions of the systems required for safe shutdown (Appendix R Fire Scenario) are included in the group	For Plausible Aging Mechanisms Applicable to These Systems	Conduct of Operations, (NO-1-100)	The demands placed on most NSR systems and components during normal operation are the same as, or greater than, the demands placed on them during mitigation of fires. Therefore, satisfactory performance of periodic functional tests can be used to demonstrate that aging is adequately managed for the passive FP functions of NSR components. A system that is in continuous operation during normal operation can be characterized as undergoing a continuous FP functional test if the system parameters (pressure, temperature, flow, etc.) encountered during performance of FP intended functions are bounded by the normal operating parameters of the system. The performance and condition monitoring activities conducted in accordance with NO-1-100 ensure detection of abnormal conditions. NO-1-100 requires that operators be accountable for their immediate areas of responsibility. This includes performing general inspections and checking the condition of areas and equipment. Operators assess degraded equipment conditions to ensure personnel and affected equipment safety while completing corrective actions. Where the above type of demonstration is successful, performance and condition monitoring activities during normal operation are credited for identifying the effects of system aging. Specific aging management programs are not necessary, and no further evaluation is required. Operator rounds have historically been 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.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
171.	5.10	FP	For FP, all NSR portions of the systems required for safe shutdown (Appendix R Fire Scenario) are included in the group	For Plausible Aging Mechanisms Applicable to These Systems	FP Program (Nuclear Program Directive SA-1)	SA-1 establishes requirements and assigns responsibilities for the FP Program at CCNPP. The FP Program is the integrated effort involving components, procedures, and personnel used to carry out all activities of the FP Program and fire prevention. It contains maintenance, testing, and inspection criteria to provide reasonable assurance that various NSR systems are capable of performing their FP intended functions. Any abnormal condition would be detected and investigated to ensure that it does not have the ability to impact safety or adversely affect operation of the system. Any such condition would be repaired prior to impacting the passive FP intended function of the system in question. Fire protection equipment and systems are inspected and tested upon initial installation and periodically thereafter. The inspection and testing is conducted following the guidance of applicable National FP Association Codes and Standards, as well as recommendations and requirements of the insurance carrier and the NRC. Plant procedures mandate test frequencies and the testing process. Applicability, compensatory actions, testing requirements, and testing frequencies for those FP systems that protect safe shutdown and SR equipment are contained in the CCNPP Technical Specifications. Plant procedures also identify compensatory actions to be taken when equipment required for 10 CFR Part 50, Appendix R, safe shutdown actions becomes inoperable.	Existing Program
172.	5.10	FP	For FP, all NSR portions of the systems required for safe shutdown (Appendix R Fire Scenario) are included in the group	For Plausible Aging Mechanisms Applicable to These Systems	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Existing Program
173.	5.11A	Auxiliary Building Heating and Ventilation	Damper seals	Elastomer Degradation, Wear	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
174.	5.11A	Auxiliary Building Heating and Ventilation	Ducts, HXs	General and Crevice Corrosion, Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
175.	5.11A	Auxiliary Building Heating and Ventilation	Damper seals	Elastomer Degradation, Wear	PM Program Repetitive Task 00322003 and Checklist MPM01159	See Section 3.1 for a description of the PM Program.	Existing Program
176.	5.11A	Auxiliary Building Heating and Ventilation	Fans	Dynamic Loading	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319. Existing procedure will be modified to include specific items with respect to discovery of this ARDM to help ensure each plausible ARDM is being adequately managed.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
177.	5.11A	Auxiliary Building Heating and Ventilation	Duct flexible collars	Elastomer Degradation, Wear	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319. Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
178.	5.11A	Auxiliary Building Heating and Ventilation	Ducts, HXs	General and Crevice Corrosion, Pitting	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319. Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
179.	5.11B	Primary Containment Heating and Ventilation	Cooling coil internal surfaces	Crevice Corrosion, Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
180.	5.11B	Primary Containment Heating and Ventilation	Piping, HVs, MOVs	General Corrosion, Crevice Corrosion, MIC, Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
181.	5.11B	Primary Containment Heating and Ventilation	HVs	Wear	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
182.	5.11B	Primary Containment Heating and Ventilation	Damper seals	Radiation Damage, Elastomer Degradation, Wear	CCNPP PM Program Checklist MPM04111 (Unit 1), MPM09005 (Unit 2)	See Section 3.1 for a description of the PM Program.	Existing Program

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
183.	5.11B	Primary Containment Heating and Ventilation	CIVs	General Corrosion, Crevice Corrosion, MIC, Pitting	Containment Leakage Rate Testing Program STP M-571I-1, STP M-571I-2, and STP M-671-1	See Section 3.3A for a description of the LLRT Program.	Existing Program
184.	5.11B	Primary Containment Heating and Ventilation	CKVs, CVs, MOVs	Wear	Containment Leakage Rate Testing Program STP M-571I-1, STP M-571I-2, and STP M-671-1	See Section 3.3A for a description of the LLRT Program.	Existing Program
185.	5.11B	Primary Containment Heating and Ventilation	Cooling coil external surfaces	Crevice Corrosion, Pitting	PM Program (MN-1-102) PM Checklists MPM09007	See Section 3.1 for a description of the PM Program.	Existing Program
186.	5.11B	Primary Containment Heating and Ventilation	Fans	Dynamic Loading	PM Program (MN-1-102) Checklists MPM09150 and MPM09151	See Section 3.1 for a description of the PM Program.	Existing Program
187.	5.11B	Primary Containment Heating and Ventilation	Fans	Dynamic Loading	PM Program (MN-1-102) Checklists MPM04112 and MPM04197	See Section 3.1 for a description of the PM Program.	Existing Program
188.	5.11B	Primary Containment Heating and Ventilation	Cooler housings	General Corrosion, Crevice Corrosion, Pitting	PM Program (MN-1-102) Checklists MPM09150 and MPM09151	See Section 3.1 for a description of the PM Program.	Existing Program
189.	5.11B	Primary Containment Heating and Ventilation	Cooler rubber boots	Radiation Damage, Elastomer Degradation, Wear	PM Program (MN-1-102) Checklists MPM09150, and MPM09151	See Section 3.1 for a description of the PM Program.	Existing Program
190.	5.11B	Primary Containment Heating and Ventilation	Cooling coil internal surfaces	Crevice Corrosion, Pitting	Specifications and Surveillance for CC/SRW Systems (CP-206)	See Section 4.1 for a description of the CP-206.	Existing Program
191.	5.11B	Primary Containment Heating and Ventilation	Fans	Dynamic Loading	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
192.	5.11B	Primary Containment Heating and Ventilation	Duct flexible collars	Elastomer Degradation, Wear	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Existing Program
193.	5.11C	Control Room and Diesel Generator Buildings HVAC	Damper seals	Elastomer Degradation, Wear	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
194.	5.11C	Control Room and Diesel Generator Buildings HVAC	Dampers, ducts, fans, filters, HXs	General Corrosion, Crevice Corrosion, MIC, Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
195.	5.11C	Control Room and Diesel Generator Buildings HVAC	Dampers, ducts, fans, filters, HXs	General Corrosion, Crevice Corrosion, MIC, and Pitting	PM Program (MN-1-102) PM Checklists MPM09109, MPM09000, MPM04169, MPM09021, MPM09115, MPM09132, MPM07111, MPM09022, and EPM30700	See Section 3.1 for a description of the PM Program.	Existing Program
196.	5.11C	Control Room and Diesel Generator Buildings HVAC	Damper seals	Elastomer Degradation, Wear	PM Program (MN-1-102) PM Checklist MPM09021	See Section 3.1 for a description of the PM Program.	Existing Program
197.	5.11C	Control Room and Diesel Generator Buildings HVAC	Fans	Dynamic Loading	Structure and System Walkdowns (MN-1-319) Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	See Section 3.1 for a description of the MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
198.	5.11C	Control Room and Diesel Generator Buildings HVAC	Duct flexible collars	Elastomer Degradation, Wear	Structure and System Walkdowns (MN-1-319) Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	See Section 3.1 for a description of the MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
199.	5.11C	Control Room and Diesel Generator Buildings HVAC	Dampers, ducts, fans, filters, HXs	General Corrosion, Crevice Corrosion, MIC, and Pitting	Structure and System Walkdowns (MN-1-319) Existing procedure will be modified to include specific items with respect to discovery of these ARDMs to help ensure each plausible ARDM is being adequately managed.	See Section 3.1 for a description of the MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
200.	5.12	Main Steam, Extraction Steam, Nitrogen & Hydrogen, Compressed Air, CVCS, FWS, Chemical Addition	Piping, CKVs, CVs, HVs, ACCs, encapsulations, FOs, HXs, MOVs, TEs, and TKs	General Corrosion, Crevice Corrosion, Pitting, Erosion Corrosion, Cavitation Erosion, Selective Leaching, Wear	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
201.	5.12	Chemical Addition	PP	Cavitation Erosion	Erosion/Corrosion Monitoring of Secondary Piping (MN-3-202)	See Section 5.9 for a description of the Erosion/Corrosion Program.	Existing Program
202.	5.12	Chemical Addition	PP, CKVs, CVs, FOs, HVs, HXs, and MOVs	General Corrosion, Crevice Corrosion, Pitting, and Erosion Corrosion	Erosion/Corrosion Monitoring of Secondary Piping (MN-3-202)	See Section 5.9 for a description of the Erosion/Corrosion Program.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
203.	5.12	Main Steam, Compressed Air	PP, HVs, PCVs, CKVs	General Corrosion, Crevice Corrosion, Pitting	IPM10000 and IPM10001	The quality of the air to IA System components that are within scope is periodically verified, in accordance with Checklists IPM10000 and IPM10001. These checklists assure that the system is being maintained in accordance with industry standards for moisture (dewpoint) and particulate contamination. Maintenance of dry air mitigates corrosion of compressed air components.	Existing Program
204.	5.12	Main Steam, Compressed Air	CVs	General Corrosion, Crevice Corrosion, Pitting, Erosion Corrosion, Wear	MSIV-4; PM Program Repetitive Tasks 10832098, 10832099, 20832089, and 20832090	Main steam isolation valves are periodically inspected as part of the plant's PM Program. These specific PM activities for each of the MSIVs require the periodic disassembly and inspection of these valves, per the requirements of procedure MSIV-04. These regularly scheduled inspections would result in the detection of the effects of degradation such that corrective action would be taken.	Existing Program
205.	5.12	Main Steam, Compressed Air	MSIV actuation system	Any Plausible Aging Effects	PM Program (MN-1-102) Repetitive Tasks 10832067, 10832068, 20832062, 20832063 (replacement program)	See Section 3.1 for a description of the PM Program.	Existing Program
206.	5.12	Main Steam	SG blowdown HXs	General Corrosion, Crevice Corrosion, and Pitting	Specifications and Surveillance for CC/SRW Systems (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
207.	5.12	Main Steam	SG blowdown radiation monitor cooler	General Corrosion, Crevice Corrosion, Pitting, and Selective Leaching	Specifications and Surveillance for CC/SRW Systems (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
208.	5.12	Chemical Addition	Piping, HVs	General Corrosion, Crevice Corrosion, and Pitting	Specifications and Surveillance for Demineralized Water, SR Battery Water, Well Water Systems, and Acceptance Criteria for On-Line Monitors (CP-202)	See Section 5.1 for a description of CP-202.	Existing Program
209.	5.12	Main Steam, Nitrogen & Hydrogen	PP, CKVs, CVs, HVs, ACCs, Encapsulations, FOs, HXs, MOVs, TEs, and TKs	General Corrosion, Crevice Corrosion, Pitting, Erosion Corrosion, Wear	Specifications and Surveillance for Secondary Systems (CP-217)	See Section 4.1 for a description of CP-217.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
210.	5.13	NSSS Sampling	HXs, HVs, and SVs	Crevice Corrosion and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
211.	5.13	NSSS Sampling	CKVs in the gas return line to containment from the Post-Accident Sampling System	Elastomer Degradation	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
212.	5.13	NSSS Sampling	Sample coolers, CVs, and HVs that are exposed to borated water (due to leakage)	General Corrosion	BACI Program (MN-3-301)	See Section 3.2 for a description of the BACI Program.	Existing Program
213.	5.13	NSSS Sampling	CVOP	General Corrosion	Check Unit 1(2) IA Quality (Checklists IPM 10000 [10001])	The quality of IA System components that are within scope is periodically verified in accordance with Checklist IPM10000 and IPM10001. These checklists assure that the system is being maintained in accordance with industry standards for moisture (dewpoint) and particulate contamination.	Existing Program
214.	5.13	NSSS Sampling	PP and Valves in the RCS hot leg sampling line	Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	See Section 4.1 for a description of the FMP.	The program will be modified by midnight, July 31, 2014 (Unit 1) or midnight, August 13, 2016 (Unit 2).
215.	5.13	NSSS Sampling	CVs in the RCS hot leg sampling lines	Wear	LLRT, Penetrations 1A, 1B, 1C (M-571A-1[2])	See Section 3.3A for a description of the LLRT Program.	Existing Program
216.	5.13	NSSS Sampling	Containment isolation SVs in the sample return lines from the reactor coolant sample hoods to the reactor coolant drain TK	Crevice Corrosion and Pitting	LLRT, Penetrations 1D, 47A, 47B, 47C, 47D, 48A, 48B, 49A, 49B, 49C (M-571I-1(2))	See Section 3.3A for a description of the LLRT Program.	Existing Program
217.	5.13	NSSS Sampling	HXs that are exposed to chemically treated water from the CC System	Crevice Corrosion and Pitting	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
218.	5.13	NSSS Sampling	Sample coolers, HVs, and SVs that are exposed to borated water (as process fluid)	Crevice Corrosion and Pitting	Specification and Surveillance Primary Systems (CP-204)	See Section 4.1 for a description of CP-204.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
219.	5.13	NSSS Sampling	Sample coolers and HVs that are exposed to steam and feedwater (as process fluid)	Crevice Corrosion and Pitting	Specifications and Surveillance for Secondary Systems (CP-217)	See Section 4.1 for a description of CP-217.	Existing Program
220.	5.14	Radiation Monitoring	PP, HVs, CVs	General Corrosion, Crevice Corrosion, and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
221.	5.14	Radiation Monitoring	CVs	Wear	LLRT, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64 (STP-M-571E-1[2])	See Section 3.3A for a description of the LLRT Program.	Existing Program
222.	5.15	SI	All SI System device types	Crevice Corrosion, General Corrosion, and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
223.	5.15	SI	Recirculation header PP	MIC	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
224.	5.15	SI	Refueling water tank (RWT) penetrations and associated welds	SCC	ARDI Program	See Section 4.1 for a description of the ARDI Program. NOTE: Susceptible locations near the RWT penetrations will be included in this program, as necessary, based on the results of an engineering review of SCC at the RWT penetrations.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
225.	5.15	SI	CKVs, CVs, HVs, HXs, MOVs, RVs, PUMPs, and TKs that are exposed to borated water (due to leakage)	General Corrosion	BACI Program (MN-3-301)	See Section 3.2 for a description of the BACI Program.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
226.	5.15	SI	PP and valves in the safety injection tank (SIT) injection mode flowpath	Fatigue	Engineering Review of CEOG Task Reports related to NRC Bulletin 88-08	Since its inception in 1988, BGE has participated in the extensive program undertaken by the CEOG to address thermal stratification concerns. In response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," BGE identified the potential for thermal stratification in the piping between the SIT outlet CKVs and the loop inlet CKVs, and subsequently confirmed the natural convection phenomenon. Since the current piping analysis for the affected portions of the SI System does not include the additional stresses imposed by thermal stratification, BGE will complete an engineering review of the industry's task reports and determine: (a) any necessary changes to the piping analyses of record for the SI System; and (b) the impact of such changes on fatigue usage parameters used by the FMP.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
227.	5.15	SI	RWT penetrations and associated welds	SCC	Engineering Review of SCC at the RWT Penetrations	The portions of the RWTs susceptible to SCC are not normally accessible for direct visual inspection. BGE will therefore complete an engineering review of SCC at the RWT penetrations that will either confirm that detection of minor leakage from the telltale holes will adequately manage SCC prior to a challenge to the structural integrity of the penetrations under design basis conditions or that will include the RWT penetrations and associated welds in an ARDI Program to verify that unacceptable degradation due to SCC at these locations is not occurring.	Commitment to be completed by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
228.	5.15	SI	PP and valves in the SIT injection and SDC mode flowpaths	Fatigue	Implementation of Fatigue Monitoring (EN-1-300)	See Section 4.1 for a description of the FMP.	Existing Program
229.	5.15	SI	SDC header return isolation MOV outside containment and the SI leakoff return isolation HVs	Crevice Corrosion and Pitting	LLRT, Penetrations 9, 10, 23, 24, 37, 39 (M-571G-1[2]) LLRT, Penetration 41 (M-571L-1[2])	See Section 3.3A for a description of the LLRT Program.	Existing Program
230.	5.15	SI	Loop inlet CKVs, SI header CKVs, and the SIT outlet CKVs	Crevice Corrosion and Pitting	Pump and Valve IST Program	The loop inlet CKVs, SIT outlet CKVs, and SI header CKVs require leak rate testing under the CCNPP Pump and Valve IST Program. This 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). Section XI, Subsection IWV, directs each licensee to comply with the applicable portions of	Existing Program Continued From Previous Page

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						ASME/ANSI OM-10. ASME/ ANSI OM-10 provides the rules and requirements for IST of CCNPP valves, including the types of tests required, frequency of testing, test procedures, 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." Pressure in the piping between the loop inlet CKVs and the SIT outlet CKVs is continuously monitored by instrumentation, with an indication in the Control Room. Monitoring these indications, which demonstrate functionally adequate seat tightness of the loop inlet CKVs on an ongoing basis in lieu of leak rate testing, is part of the overall CCNPP Pump and Valve IST Program. Excessive back leakage through a loop inlet CKV would result in alarm actuation and assessment of the leakage. To ensure such leakage from the RCS will be detected, observation of alarm function is documented as part of the SIT outlet CKV closure verification. If unidentified RCS leakage exceeds the acceptance criteria provided in the CCNPP Technical Specifications, the applicable abnormal operations procedures are implemented. Appropriate corrective actions are determined in accordance with the CCNPP Technical Specifications, Surveillance Test Program procedures, and the CCNPP Corrective Actions Program Calvert Cliffs procedures STP O-65J-1(2), which verify the closure and seat leakage integrity of the SIT outlet CKVs and the SI header CKVs, are also part of the overall CCNPP Pump and Valve IST Program. The SIT outlet CKVs and the SI header CKVs are tested in accordance with ASME/ANSI OM-1987, including OMa-1988 Addenda. Completion of the SIT outlet CKV and SI header CKV closure verification in accordance with STP O-65J-1(2) satisfies the biennial seat leakage measurement requirement.	

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Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
231.	5.15	SI	Low pressure safety injection pump seal HXs and high pressure safety injection Pump seal coolers	General Corrosion, Crevice Corrosion and Pitting	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
232.	5.15	SI	All SI System device types that are exposed to borated water (as process fluid)	General Corrosion, Crevice Corrosion and Pitting	Specification and Surveillance Primary Systems (CP-204)	See Section 4.1 for a description of CP-204.	Existing Program
233.	5.15	SI	RWT penetrations and associated that are exposed to borated water (as process fluid)	SCC	Specification and Surveillance Primary Systems (CP-204)	See Section 4.1 for a description of CP-204.	Existing Program
234.	5.15	SI	RWT HXs	Crevice Corrosion and Pitting	Specification and Surveillances Demineralized Water, SR Battery Water, & Well Water (CP-202)	See Section 5.1 for a description of CP-202.	Existing Program
235.	5.15	SI	RWT penetrations and associated welds	SCC	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
236.	5.15	SI	RWT perimeter seal	Weathering	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
237.	5.16	Saltwater (SW)	Internally lined PP, BSs, CKVs, CVs, HVs and PUMPs	Crevice Corrosion, Galvanic Corrosion, General Corrosion, MIC, Pitting, Selective Leaching and Elastomer Degradation	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
238.	5.16	SW	Shell side of the CC and SRW HXs and susceptible areas of the Unit 1 plate and frame HXs	Crevice Corrosion, General Corrosion, and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
239.	5.16	SW	Internally lined PP, AVVs, CKVs, CVs, FEs, HVs, RVs, TIs, and TPs	Crevice Corrosion, General Corrosion, MIC, and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
240.	5.16	SW	CC and SRW HXs	Crevice Corrosion, Erosion Corrosion, General Corrosion, MIC, Pitting, and Elastomer Degradation	PM Program (MN-1-102) For affected components: <u>Repetitive tasks</u> 10152023; 10152024; 20112006; 20112027; 20152020; and 20152021 <u>Checklists</u> MPM00005 and MPM00006	See Section 3.1 for a description of the PM Program.	Existing Program
241.	5.16	SW	FOs	Crevice Corrosion, Erosion Corrosion, MIC, Particulate Wear Erosion, and Pitting	PM Program (MN-1-102) For affected components: <u>Repetitive tasks</u> 10122095 and 20122099	See Section 3.1 for a description of the PM Program.	Existing Program
242.	5.16	SW	Internally lined PP, BSs, CKVs, CVs, HVs and PUMPs	Crevice Corrosion, Galvanic Corrosion, General Corrosion, MIC, Particulate Wear Erosion, Pitting, and Elastomer Degradation	PM Program (MN-1-102) For affected components: <u>Repetitive tasks</u> 10122063 through 10122068; 10122096 through 10122102; 20122067 through 20122072; 20122100 through 20122106; 10122086 through 10122088; 10122107 through 10122110; and 20122092 through 20122094; <u>Checklists</u> MPM04194; MPM01180; and MPM01181 <u>Procedure</u> PUMP-03	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
243.	5.16	SW	ECCS Pump Room air coolers	Crevice Corrosion, General Corrosion, MIC, and Pitting	PM Program (MN-1-102) For affected components: Checklists MPM05000 and MPM05101 (modification needed)	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
244.	5.16	SW	ACCs, CVs, HVs, and PCVs, with air internal environment	General Corrosion	PM Program (MN-1-102) For affected components: Checklists IPM10000 and IPM10001	See Section 3.1 for a description of the PM Program.	Existing Program
245.	5.16	SW	CC and SRW HXs	Crevice Corrosion, General Corrosion, and Pitting	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
246.	5.16	SW	SW System bolting	General Corrosion	Structure and System Walkdowns (MN-1-319)	See Section 3.1 for a description of MN-319.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
247.	5.17	SRW	PP, CKVs, CVs, FEs, FOs, HVs, PUMPs, REs, RVs, TEs, TIs, TKs subject to crevice corrosion and pitting	Crevice Corrosion and Pitting	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
248.	5.17	SRW	PP including non-SR portions of SRW piping serving Turbine Building loads	Erosion Corrosion	ARDI Program	See Section 4.1 for a description of the ARDI Program. 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.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
249.	5.17	SRW	PP, CKVs, CVs, HVs, PUMPs, RVs, TIs, TKs subject to general corrosion	General Corrosion	ARDI Program	See Section 4.1 for a description of the ARDI Program. 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.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
250.	5.17	SRW	CVs, HVs, and PUMPs subject to selective leaching	Selective Leaching	ARDI Program	See Section 4.1 for a description of the ARDI Program. 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.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
251.	5.17	SRW	Air-operated valves	General Corrosion	Periodic maintenance and verification of dryer effectiveness: Check Unit 1 IA Quality (IPM10000), and Check Unit 2 IA Quality (IPM10001)	The quality of IA System components that are within scope is periodically verified, in accordance with Checklist IPM10000 and IPM 10001. These checklists assure that the system is being maintained in accordance with industry standards for moisture (dewpoint) and particulate contamination. Mitigation of general corrosion of the SRW air-operated valves. 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.	Existing Program
252.	5.17	SRW	PP, CKVs, CVs, FEs, FOs, HVs, PUMPs, REs, RVs, TEs, TIs, TKs subject to crevice corrosion and pitting	Crevice Corrosion and Pitting	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
253.	5.17	SRW	PP, CKVs, CVs, HVs, PUMPs, RVs, TIs, TKs subject to general corrosion	General Corrosion	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program
254.	5.17	SRW	CVs, HVs, and PUMPs subject to selective leaching	Selective Leaching	Specification and Surveillance CC/SRW System (CP-206)	See Section 3.1 for a description of the CP-206.	Existing Program
255.	5.17	SRW	PUMPs	General Corrosion, Crevice Corrosion and Pitting	SRW Pump Overhaul (PUMP-15)	The SRW pumps are inspected for general corrosion, crevice corrosion/pitting using PUMP-15. PUMP-15 instructs the user to inspect certain pump components for erosion, wear, and mechanical damage. The procedure will be modified to include inspections for general corrosion, crevice corrosion/pitting on the pump casing and bushings. The procedure directs the user to contact the System Engineer if any of these indications are found, and to replace parts as necessary.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
256.	5.18	SFPC	Diaphragm HVs	Rubber Degradation	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
257.	5.18	SFPC	All items that are exposed to borated water (due to leakage)	General Corrosion	BACI Program (MN-3-301)	See Section 3.2 for a description of the BACI Program.	Existing Program
258.	5.18	SFPC	Containment isolation HVs	Wear	LLRT, Penetrations 15, 16, 18, 38, 59, 60, 61, 62, 64 (STP-M-571E-1[2])	See Section 3.3A for a description of the LLRT Program.	Existing Program
259.	5.18	SFPC	SFP demineralizer and filter	General Corrosion	Repetitive Task 10672001	See Section 3.1 for a description of the PM Program. The repetitive task will be modified to explicitly call for inspection of the components for signs of boric acid corrosion.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
260.	5.18	SFPC	SFPC PUMPs	Cavitation Erosion, Erosion Corrosion	Repetitive Tasks 00672007, 00672008	See Section 3.1 for a description of the PM Program. Repetitive tasks will be modified to explicitly present inspection requirements.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
261.	5.18	SFPC	All items that are exposed to borated water (as process fluid)	General Corrosion	Specification and Surveillance CC/SRW System (CP-206)	See Section 4.1 for a description of CP-206.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
262.	6.1	Cables	EPR/XLPE insulated power cables EPR/XLPE/XLPO instrumentation cables in critical service	Thermal and Radiative Effects Insulation Resistance Reduction of Instrumentation Cables	Cables Aging Management Program	BGE is committed to managing the cable commodity during the period of extended plant operation as follows: • The ethylene-propylene-rubber (EPR)/ crosslinked polyethylene (XLPE) insulated cables that are in power service, routed with maintained spacing, and subject to plausible thermal aging are going to be monitored with an aging management program. This program will ensure that cable replacement would occur prior to any cable functional failure. BGE is working to define a conditioning monitoring program that will provide acceptance criteria and testing/analysis to determine at what point the cables should be replaced. • The EPR/XLPE insulated cables in power service that run inside of Containment and subject to plausible synergistic thermal and radiative aging are also going to be monitored by an aging management program. This program will ensure that cable replacement would occur prior to any cable functional failure. BGE is working to define a conditioning monitoring program that will provide any necessary acceptance criteria and the testing and analysis that would be required to determine at what point the cables would actually be replaced. • EPR/XLPE/crosslinked polyolefin (XLPO) insulated instrumentation cables in critical service are subject to plausible insulation resistance reduction, which is managed by the existing MN-1-211 instrument calibration program. • EPR cable terminations associated with 4 kV SW and SRW pumps are subject to thermal aging. The aging will be managed by existing EPMs 04000, 04003, and 05135.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
263.	6.2	Electrical Commodities	Battery terminals/ charger and inverter cabinets	Electrical Stressors, General Corrosion, and Wear	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
264.	6.2	Electrical Commodities	Breaker cabinets	Electrical Stressors, Wear, and Fatigue	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
265.	6.2	Electrical Commodities	Bus cabinets	Electrical Stressors, Wear, and Fatigue	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
266.	6.2	Electrical Commodities	Bus cabinets	Electrical Stressors, Wear, and Fatigue	PM Program (MN-1-102) New repetitive tasks	See Section 3.1 for a description of the PM Program.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
267.	6.2	Electrical Commodities	Motor-control cabinets panels	Electrical Stressors, Wear, Fatigue, and Dynamic Loading	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
268.	6.2	Electrical Commodities	Motor-control cabinets panels	Electrical Stressors, Wear, Fatigue, and Dynamic Loading	PM Program (MN-1-102) New repetitive tasks	See Section 3.1 for a description of the PM Program.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
269.	6.2	Electrical Commodities	Miscellaneous panels	Electrical Stressors, Wear, Fatigue, and Dynamic Loading	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
270.	6.2	Electrical Commodities	Miscellaneous panels	Electrical Stressors, Wear, Fatigue, and Dynamic Loading	PM Program (MN-1-102) New repetitive tasks	See Section 3.1 for a description of the PM Program.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
271.	6.2	Electrical Commodities	Local control station panels	Electrical Stressors, Wear, Fatigue, and General Corrosion	PM Program (MN-1-102) Certain existing repetitive tasks	See Section 3.1 for a description of the PM Program. These PM tasks will be modified to include specific ARDMs where they are not presently included and/or additional specified components/ subcomponents where they are not presently inspected.	Program to be modified by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
272.	6.2	Electrical Commodities	Local control station panels	Electrical Stressors, Wear, Fatigue, and General Corrosion	PM Program (MN-1-102) New repetitive tasks	See Section 3.1 for a description of the PM Program.	Program to be implemented by midnight July 31, 2014 (Unit 1) or midnight August 13, 2016 (Unit 2).
273.	6.3	EQ Equipment	All long-lived components on the EQ Master List	Thermal, Radiative, and Kapton-Unique Aging Effects	CCNPP 10 CFR 50.49 Program	BGE will continue to execute its 50.49 Program during the period of extended operation. The Calvert Cliffs 50.49 Program will continue to be administered in accordance with the regulatory requirements of 10 CFR 50.49, the Division of Operating Reactors Guidelines as transmitted by NRC Bulletin 79-01B, and NUREG-0588. The program includes requirements for determining the components in scope per 10 CFR 50.49 and options for management of thermal and radiative aging of components found to be in the scope of 10 CFR 50.49. The program contains the elements necessary to ensure that 50.49 equipment will remain qualified to execute the required 50.49 function(s) under all design loading conditions should a design basis event occur at the end of extended plant life.	Existing Program
274.	6.4	Instrument Lines	Small bore PP, tubing, fittings, HVs and non-pressure sensing instruments	Conditions Adverse to Quality In Main Process Lines	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).
275.	6.4	Instrument Lines	Instrument line supports	General Corrosion and Elastomer Hardening	ARDI Program	See Section 4.1 for a description of the ARDI Program.	Program to be performed prior to, and near, the end of the current license period (e.g., no sooner than five years prior to expiration of the current license term).

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Significant Program Features Warranting Regulatory Control

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
276.	6.4	Instrument Lines	Instrument line supports	General Corrosion	Control of Shift Activities (NO-1-200)	NO-1-200 provides for discovery of conditions that could allow general corrosion to progress for the instrument line supports by performance of visual inspections during plant operator rounds. Under this program, plant operators inspect accessible operating spaces each shift. The containment is also inspected once per shift when the plant is shutdown and the containment is open for normal access. Conditions adverse to quality that are identified during the operator rounds are documented and resolved by the CCNPP Corrective Actions Program. The program provides guidance for specific conditions to inspect for when performing the walkdowns. 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. The corrective actions taken as a result of this program will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.	Existing Program

Item No.	LRA Section	System	Components	Aging Mechanism	Program	Program Description	Implementation Schedule
277.	6.4	Instrument Lines	Instrument line supports	General Corrosion	Ownership of Plant Operating Spaces (NO-1-107)	NO-1-107 provides for discovery of general corrosion (or conditions that could allow general corrosion to progress) for the instrument line supports by performance of visual inspections of plant operating areas. The purpose of the program is to provide requirements and guidance on personnel accountability for the correction of housekeeping, material, and radiological deficiencies. Under this program, owners are identified within each space and provide a point of contact for any individual who finds deficiencies or any concern with the space. Conditions adverse to quality that are identified are documented and resolved by the CCNPP Corrective Actions Program The program provides guidance for types of deficiencies to look for when performing the inspections. Inspection items related to aging management include the following: • Items related to specific ARDMs such as corrosion; • Effects that may have been caused by ARDMs such as loose lines/pipes, loose fasteners, or leakage of fluids; and • Conditions that could allow progression of ARDMs such as unbracketed lines/pipe, missing fasteners, inadequate paint, or leakage of fluids. The corrective actions taken as a result of this program will ensure that the instrument line supports remain capable of performing their passive intended function under all CLB conditions.	Existing Program

Component Key

ACC	Accumulator	HDR	Hold-down Ring
AVV	Auto Vent Valve	HV	Hand Valve
BS	Basket Strainer	HX	Heat Exchanger
CEASB	CEA Shroud and Bolts	LSSBA	Lower Support Structure Beam Assembly
CEDM	Control Element Drive Mechanism	MOV	Motor Operated Valve
CKV	Check Valve	PCV	Pressure Control Valve
CS	Core Shroud	PP	Piping
CSB	Core Support Barrel	PUMP	Pump/Driver Assembly
CSBA	Core Support Barrel Alignment Key	PZV	Pressure Vessel
CSC	Core Support Columns	RE	Radiation Element
CSP	Core Support Plate	RV	Relief Valve
CSTR	Core Shroud Tie Rod and Bolts	RWT	Refueling Water Tank
CV	Control Valve	SV	Solenoid Valve
CVOP	Control Valve Operator	TE	Temperature Element
ERV	Electro-Relief Valve	TI	Temperature Indicator
ESG	CEA Shroud Extension Shaft Guides	TIC	Temperature Indicating Controller
FAP	Fuel Alignment Pins	TK	Tank
FE	Flow Element	TP	Temperature Test Point
FO	Flow Orifice	UGSP	Upper Guide Support Plate

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Docket Numbers 50-317 and 50-318 D.L. Solorio, NRC Project Manager

11. ABSTRACT *(200 words or less)*

This safety evaluation report (SER) documents the technical review of the Calvert Cliffs Nuclear Power Plant (CCNPP), Units 1 and 2 license renewal application (LRA) by the U.S. Nuclear Regulatory Commission staff. The Baltimore Gas and Electric Company (BGE) requested renewal of the Class 104b operating licenses for the Calvert Cliffs units for a period of 20 years beyond the current expiration dates. By letter dated April 8, 1998, BGE submitted a LRA for Calvert Cliffs required by Part 54 of Title 10 of the Code of Federal Regulations.

On the basis of its evaluation of the LRA the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis for the CCNPP, Units 1 and 2 during the period of extended operation.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

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