Safety Evaluation Report for Calvert Cliffs License Renewal Application

Publication Information

Safety Evaluation Report

Related to the License Renewal of Calvert Cliffs Nuclear Power Plant Units 1 and 2

Safety Evaluation Report with Open Items and Confirmatory Items

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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 is requesting 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 Title 10 of the Code of Federal Regulations Part 54 (10 CFR Part 54).

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 status of the staff's review of information submitted to the NRC through March 5, 1999, the cutoff date for consideration in the SER. The staff has identified open items that must be resolved before it can make a determination on the application. These items are summarized in Section 1.4 of this report. In order to close these items, the staff requires the additional information identified in this report. The staff will provide its final conclusion on the

review of the Calvert Cliffs license renewal application in an update to this SER.

1 Introduction and General Discussion

- 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 Project Directorate for License Renewal, 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. Unless otherwise noted, the staff reviewed and considered information submitted through March 5, 1999. Information received after that date was reviewed on a case-by-case basis, depending on the stage of the safety review. 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, and at the Calvert County Public Library, 30 Duke Street, Prince Frederick, Maryland 20678.

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.

Sections 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. Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). The conclusions of this report are given in Section 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 provides a summary of the staff's onsite review activities and references to any relevant inspection reports, and specifically identifies any inspection results that were used, in part, as the basis for the staff's conclusions.

In accordance with 10 CFR Part 51, the staff will prepare 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 will be 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.
•	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 principals, 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. The draft and final plant-specific supplement to the GEIS will be prepared by the staff separate from this report.

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. Should the license numbers be changed on issuance of the renewed license, the staff will make conforming changes to Item 3 of the attachment, and any other sections of the indemnity agreement as appropriate. Therefore, the requirements of 10 CFR54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewal 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 Sections 2, 3, and 4 of this report.

The staff's evaluation of the environmental information required by 10 CFR 54.23 will be found in the draft and final plant-specific supplements to the GEIS that state the considerations related to renewing the license for the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. These documents will be prepared by the staff separate from this report.

When the report of the Advisory Committee on Reactor Safeguards required by 10 CFR 54.25 is issued, it will be incorporated into Section 5 of this SER. The finding required by 10 CFR 54.29 will be placed in Section 6 of this report.

1.4 Summary of Open Items

As a result of its review of the license renewal application for Calvert Cliffs, including the additional information provided to the NRC through March 5, 1999, the staff identified the following issues that remained open at the time this report was prepared. An issue is open if BGE has not provided a sufficient basis for its resolution, or has not yet provided requested information and the staff is unaware of what will be included in the promised submittal. Each open item has been assigned a unique identifying number, which identifies the section in this report where the open item is described. For example, Open Item 3.0-1 is discussed in Section 3.0 of this report.

Item	Description

2.2.3.8-1	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 the license renewal application (LRA) addresses the safety-related diesel buildings but does not address the station blackout (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 license renewal application (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 emergency diesel generator (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 is considering whether 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 emergency diesel generator building’s intended safety function, should be included within the scope of license renewal.

2.2.3.17.2.1-1	In response to NRC Question No. 5.6.4, regarding exclusion of the emergency dousing function of the containment spray (CS) system from the scope of license renewal, the applicant referenced Section 6.7.2 of the UFSAR, which explains that the dousing system is isolated in Modes 1 through 4. Licensee calculations show that the maximum post-loss-of-coolant accident charcoal bed temperature will not cause iodine desorption or charcoal bed ignition. However, the licensee states that the system is available to provide fire protection to the charcoal beds in order to support certain maintenance activities in Modes 5 and 6. 10 CFR 50.48 guided the staff to evaluate the plants' fire protection features as satisfying the provisions of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 and reflects this evaluation in the Fire Protection SER. In Section F of Appendix A to BTP APCSB 9.5-1, charcoal filters are identified as needing automatic fixed suppression systems due to their inaccessibility during normal plant operations. Further, Section 4, "Ventilation," states that fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52. The fixed fire suppression system used in this application consists of the water supply piping and direction nozzles. The staff reviewed the applicant's response and found no new information that would support the licensee's conclusion that the piping and nozzles that provide the emergency dousing function do not meet the scoping requirements of 10 CFR 54.4(a)(3).

2.2.3.23.2.1-1	Section 5.11B.1.2 in 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 steam generator (SG) compartment and reactor vessel annulus. As a result, the staff questioned that 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 with 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. The staff is 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; therefore, this is an Open Item.

2.2.3.30-1	Since the non-safety-related service water (SRW) header is credited with preserving cooling water inventory in the safety-related portions of the 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 [per 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 because it only 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 is the staff's opinion that the information in the cited references reinforces 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).

2.2.3.33.2.2-1	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"). 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.
3.0-1	The content of the final safety analysis report (FSAR) supplement is dependent upon the final bases for the staff's safety evaluation, as will be reflected in a subsequent revision to this report. In addition, improved guidance is being developed for updating the contents of FSARs under 10 CFR 50.71(e). Therefore, the resolution of the information that needs to be added to the FSAR will be addressed after the other open and confirmatory items are resolved, prior to issuance of a renewed license. The content of the FSAR will be tracked as an Open Item.
3.1.4.3-1	In Section 3.2 of Appendix A to the license renewal application, the applicant discussed how some internal portions of the reactor vessel (RV) cooling shroud can harbor pockets of liquid that may be inaccessible for visual inspection without removing interference. The staff's understanding of the boric acid corrosion inspection program is that it does not provide for removing interference; thus, it is unclear how the applicant is managing this aging issue.

3.1.6.3-1	The staff identified several systems in which the applicant proposed to use a one-time age-related degradation inspection to manage age-related degradation mechanism that obviously require periodic, regular inspections, such as for verification of acceptable condition of coatings (auxiliary feedwater, component cooling water, auxiliary building heating and ventilation), and verification that corrosion is not occurring due to leakage (SW, nuclear steam supply system sampling, spent fuel pool cooling). The staff requests that the applicant either expand existing programs (e.g., the boric acid corrosion inspection (BACI) program or the structure and system walkdowns) or confirm that a new aging management program will be developed to ensure that regular, periodic inspections will be performed for these systems.

3.2.3.1.1-1	The staff noted that the applicant did not consider the steam generator carbon steel tube support structures as susceptible to erosion-corrosion. The applicant, in its response to Generic Letter (GL) 97-06, “Degradation of Steam Generator Internals,” referenced a Combustion Engineering topical report that states erosion corrosion is a plausible age-related degradation mechanism (ARDM) under certain conditions. The staff requests that the applicant include erosion-corrosion of the tube support structures as a plausible ARDM to be managed for license renewal and the staff requests that the applicant submit an appropriate aging management program. In a letter dated November 19, 1998, the applicant stated that it performs periodic visual inspections of the secondary side of the steam generators (in particular the egg-crates and tube support plates) to look for signs of erosion and tube bundle fouling. However, the staff does not have enough information to conclude that this description of the applicant actions is enough to ensure the applicant will detect aging effects before there is a loss of intended function. Specifically, the applicant needs to clearly identify erosion corrosion of the egg-crate supports as a plausible ARDM, and also needs to provide the specific inspection scope, the inspection frequency, and the acceptance criteria for these visual inspections. The staff is also reviewing separately the applicant’s response to GL 97-06 and will provide additional feedback relevant to this issue upon closeout of that GL.

3.2.3.1.1-2	In view of industry experience and data, the staff considers stress corrosion cracking (SCC) to be plausible for some pressurizer and reactor coolant system (RCS)components, and should be managed by aging-management programs (AMPs). The staff would consider the following existing programs to be 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 Bulletin 82-02, “Degradation of Threaded Fasteners in the RCS Pressure Boundary of PWR Plants;” primary water chemistry control program. The staff would rely on these programs 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 must propose an acceptable alternative.
3.2.3.1.2-1	In 10 CFR 54.21(a)(3), the Commission requires that, for each component subject to AM, the applicant must demonstrate that the effects of aging will be adequately managed for the period of extended operation. The open issue pertains to the applicant’s development of the scope of the fatigue monitoring program (FMP) for the reactor pressure vessel (RPV) and RCS components. The applicant has not completed its evaluation to identify the reactor pressure vessel (RPV) and reactor coolant system (RCS) components to be monitored by the FMP. Although the applicant stated it selected the components for monitoring on the basis of highest fatigue usage, the applicant has not completed evaluation of all RPV and RCS components. These additional component evaluations may result in the identification of additional locations that require monitoring by the FMP. As a consequence, the scope of the FMP, including the parameters that will be monitored by the FMP, has not been completely defined. The applicant should:

	• Describe the scope of the Combustion Engineering review that formed the basis for selecting the critical locations monitored by the FMP.
	• Complete the one-time fatigue analysis of the reactor coolant pumps (RCPs), motor operated valves (MOVs), and pressurizer relief valves (PRVs), and modify the FMP as necessary. 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.
	• Complete the evaluation of the control element drive mechanism (CEDM) and reactor vessel level monitoring system (RVLMS) components and modify the FMP as necessary. 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.
	• Complete the evaluation of the reactor vessel internals (RVI) 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.
3.2.3.2.1-1	The applicant must identify Technical Specification (TS) limits on steam generator (SG) leakage, which provide for defense in depth related to the detection of degradation in the steam generator tubes. The staff considers the TS limit of SG leakage to be a necessary component of an AMP for SG tubes.

3.2.3.2.1-2	In view of the SCC experience by the head closure seal leakage detection line and the safety consequences of a leak (a small break loss of coolant accident), the applicant needs to propose an AMP for SCC. The program the applicant proposed, RV-78, is merely mitigative.
3.2.3.2.1-3	For the cracking of pressurizer shell, heads, including cladding cracking, the applicant stated that cracking was not plausible and did not need aging management. Industry experience has shown that cracking is a plausible ARDM that requires aging management, typically by inspections. The applicant should propose an AMP.
3.2.3.2.1-4	The applicant should perform an augmented inspection of small-bore piping for renewal. The augmented inspection would include Inconel materials, and the information resulting from the response to Information Notice 90-10 should be considered in developing the augmented inspection of Inconel materials.
3.2.3.2.4-1	The applicant should present a discussion of 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.
3.4.3.2.1-1	For the chemical and volume control system (CVCS), 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 to be managed. There are no parameters monitored or inspected as part of this plant modification. However, the staff believes there should be 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.

3.4.3.2.1-2	BGE should provide justification and an implementation schedule for the plant modification in the chemical and volume control system for mitigation of potential stress corrosion cracking caused by the original heat tracing adhesive.
3.4.3.2.2-1	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 heat exchanger (HX) and temperature element (TE) components. In a meeting on February 18, 1999 (NRC meeting summary dated March 19, 1999), 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 a Combustion Engineering report. 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. The applicant should supplement its response to NRC Question 7.1 to include the review of the TE and HXs discussed above.

3.7.3.1.1.1-1	The applicant states that the external surfaces of the diesel fuel oil 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). The staff disagrees 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. Therefore, the staff finds that the applicant needs to identify both coatings and cathodic protection for buried pipelines to be within the scope of license renewal.

3.9.3.2.3-1	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 nuclear steam supply system (NSSS) sampling system. The licensee has stated that there are no practicable means available to mitigate the effects of thermal fatigue, but has established a 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 under 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

3.10.3.2.1-1	In NRC Question No. 3.3.12, the staff asked the applicant to summarize the time-limited aging analysis (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 the letter from the applicant (October 28, 1997), the vertical tendons, in general, possess reasonable tendon lift-off force margins in the order of 25 kips. The staff requested 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 extended period of operation.

	In addition, 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 do this. 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 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 surveillance. 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. Because this type of information is not available in the LRA, the staff cannot make a safety judgment regarding the applicant's TLAA for tendon prestressing force in containment at this time. This item is considered as a part of this Open Item.

3.10.3.2.2-1	In NRC Question No. 3.3.36, the staff raised a concern about sustained exposure of below-grade concrete slabs and walls of the intake structure 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 two out of three 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 west side indicated very high chloride and sulfate content. In a telephone conference on March 2, 1999, the staff requested 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.
3.10.3.2.3-1	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 has not addressed the aging effects of radiation and temperature upon these and other non-metallic elements.

3.11.3.2.2.1-1	BGE should provide information and/or the basis to demonstrate how the preventive maintenance tasks for managing the effects of general corrosion/oxidation for FHE and HLHC systems will be implemented and why this program adequately manages aging.
4.1.3-1	The list of TLAAs provided pursuant to 10 CFR 54.21(c)(1) does not include the upper-shelf energy 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, that irradiation embrittlement as measured by the drop in Charpy upper shelf energy (USE) is not a time-limited aging analysis (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. The applicant should include upper shelf energy evaluation in their list of TLAAs. This Open Item should be resolved in conjunction with Confirmatory Item 3.2.3.2.1-2.
4.1.3-2	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, etc. The calculation of normalized lift-off 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 lift-off 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 lift-off force will be recalculated by the year 2012 to account for the period of extended operation. The deferral of the recalculation of the parameter for the renewal term is, therefore, identified as an open item. The details of this open item are set forth in Section 3.10 of this SER.

4.1.3-3	With respect to metal fatigue (from thermal cycles) of USAS B31.7 class II and III 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, their data search did not identify this issue as a TLAA. In the application, however, the applicant discusses expected cycles during the period of extended operation for some components. These assessments as TLAAs. In addition, during the site meeting, the applicant indicated that the number of cycles was considered in their evaluation of class II and III piping. Hence, the applicant should identify its assessment as a TLAA.

1.5 Summary of Confirmatory Items

As a result of the staffs' review of BGE's application for license renewal, including the additional information and clarifications provided subsequently, the staff identified the confirmatory items listed below, as of the time this report was prepared. Confirmatory items reflect commitments made by BGE or staff actions for which the resolution has not yet been documented or confirmed. In addition, confirmatory items include significant matters that need to be considered as possible license conditions or technical specification requirements, depending on the form of the resolution. Each Confirmatory Item has been assigned a unique identifying number, which identifies the section in this report where the Confirmatory Item is described. For example, Confirmatory Item 3.0-1 is discussed in Section 3.0 of this report.

Item	Description

2.2.3.4.2.2-1	Table 3.3A-1, “Containment Structure Component Types Requiring an aging management review (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 give 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 is a confirmatory item.
2.2.3.17.2.2-1	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. 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 Section(see Section 2.2.3.15.2.2) is a Confirmatory Item.

3.1.3.3-1	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, is an oversight. As such, the structure walkdown reports will be modified to detect the aging effects of reinforced-concrete structures. This is a Confirmatory Item.
3.1.4.3-1	The applicant plans to modify the boric acid corrosion inspection program to specify examinations during each refueling outage of the reactor vessel cooling shroud anchorage to the reactor vessel head for evidence of borated water leakage and all RV cooling shroud structural support members for general corrosion/oxidation. A Confirmatory Item will be used to capture this modification and its schedule.
3.1.5.3-1	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" to indicate that the applicant's Appendix B program also applies to non-safety related structures and components that are subject to aging management review for license renewal, such that any changes to the programs or activities that may affect their effectiveness in managing aging can be appropriately controlled.

3.2.3.2.1-1	The technical bases for the CASS program is contained in EPRI Technical Report 106092. 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 embrittlement, and do require inspection. The proposed screening criteria and inspection are acceptable when revised in accordance with the criteria documented during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999). The applicant should revise the CASS program as discussed in the February 16, 1999, meeting.
3.2.3.2.1-2	The applicant should revise the comprehensive reactor vessel surveillance program as discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999).
3.2.3.2.1-3	To manage aging effects associated with SCC of alloy 600 RPV components, the applicant relies on its alloy 600 program. The applicant stated that the Alloy 600 program does not predict primary water stress corrosion cracking (PWSCC) to be an issue for the period of extended operation. The applicant plans to continue its periodic visual inspections to verify this prediction. The staff requests that the applicant confirm that CEDMs are included in the periodic inspections via the BACI program, confirm that cracking of CEDMs has been considered for a 60-year life, and provide the results of the susceptibility evaluation for the CEDMs relative to this time frame, and provide operating experience from inspections of CEDM nozzles at CCNPP, if available.

3.2.3.2.1-4	To manage aging effects associated with SCC of the control element assembly (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 is above or below the "critical stress" for SCC. As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.15, the applicant indicated that after further review, the function of the CEA shroud bolts is not safety related and, therefore, this stress analysis program would not be implemented. This is a confirmatory item pending review of an applicant submital documenting this finding.
	In addition, An ARDI program is planned to manage the effects of SCC of the CEA shroud bolts. However, as discussed in 3.2.3.2.1C(8) of this SER, the applicant indicated that the CEA shroud bolts do not perform a safety function in accordance with the requirements of 10 CFR 54.4. The applicant was asked to document the resolution of the issue with a description of the function of the CEA shroud bolts that included an explanation of why they do not meet the criteria contained in 10 CFR 54.4.
3.2.3.2.4-1	The applicant should document the basis for not considering the hold down ring as a device subject to stress relaxation.
3.2.3.3-1	If generic safety issue (GSI) 190 is not resolved generically prior to CCNPP operation in the extended period, the applicant must adequately resolve environmental effects on high usage factors with bounding analyses or a monitoring program on a plant-specific basis.

3.3.3.2.1-1	The licensee plans to modify MN-1-319 to (a) specifically identify the field-erected tanks within the scope of the performance assessments, (b) provide additional visual inspection criteria specific to detecting leakage near the refueling water tank (RWT) penetrations, and (c) add guidance regarding approval authority for significant departures from the specified walkdown inspection scope and schedule.
3.3.3.2.1-2	The licensee plans to perform an engineering evaluation of SCC at the RWT penetrations to either (a) confirm that detection of leakage through the “telltale” holes is adequate to manage stress-corrosion cracking (SCC) before a challenge to the structural integrity of the penetrations or (b) include RWT penetrations in the (ARDI) program.

3.3.3.2.2-1	10 CFR Section 54.21(a)(3) requires that for each component subject to AMR, the applicant demonstrate that the effects of aging will be adequately managed. The staff concern pertains to how the applicant demonstrated that fatigue will be adequately managed for the safety injection (SI) piping. Section 5.15 of the LRA indicates that the applicant identified the potential for thermal stratification in the piping between the SI tank check valves and the loop inlet check valves. The LRA also indicates that the applicant will complete an engineering review of the industry task group reports regarding thermal stratification to determine whether SI piping changes are necessary and to determine the impact of such changes on fatigue usage parameters used by the CCNPP fatigue monitoring program (FMP). In NRC Question No. 7.21, the staff asked that the applicant indicate whether the plans for the engineering review include reanalysis for thermal stratification and that the applicant describe the manner by which the time-limited aging analysis (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 SI tank 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. The applicant should 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. The applicant should complete the thermal stratification analysis of the SI piping and modify the FMP as necessary.
3.3.3.2.3-1	The licensee plans to modify MN-1-319 to include additional visual inspection criteria specific to the perimeter seal.

3.4.3.2.2-1	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. In a meeting on February 10, 1999 (NRC meeting summary dated March 19, 1999), held at CCNPP, the applicant stated that it plans to revise the LRA position 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.
3.6.2.1.4-1	In Section 5.11C.1.4 of the LRA, the applicant explains that the newly installed heating ventilation and air conditioning (HVAC) system in the diesel generator building is similar to the system for the control room, and it does not need additional AMR. However, to justify such a conclusion, the applicant should 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.

3.10.3.2.2-1	The applicant considered freeze-thaw as a plausible 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 in.) 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 was 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

3.10.3.2.5 -1	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-1-139 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 structures, systems, and components so that any abnormal or degraded condition will be identified and documented, and corrective actions will be taken before these structures, systems, and components 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) to help 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.

4.1.3-1	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 the February 16, 1999, meeting summary, the applicant has provided an evaluation demonstrating that the current analysis remains valid for the period of extended operation. The staff has reviewed this information and found it acceptable. However, this information should be documented.

2 Structures and Components Subject to Aging Management Review

2.1 Methodology for Identifying Structures and Components Subject to 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 submitted their “Integrated Plant Assessment Methodology”, which was subsequently amended to incorporate changes required by the staff. The amendment to the IPA was provided in a BGE letter dated January 11, 1996. The staff reviewed this methodology and found it to be acceptable as documented in a Final Safety Evaluation (FSE) dated April 4, 1996. BGE license renewal application 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 SER.

2.2 Identification of Structures and Components Subject to 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 Evaluation Approach

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 significant 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 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 memorandum 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 managment review (AMR) as required by 10 CFR 54.21(a)(1) would be identified.

To ensure that the IPA methodology described in Section 2.0 of Appendix A to the LRA was implemented properly 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 111 systems and 24 structures at CCNPP listed in Table 3-1 in Section 2.0 to 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 the 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 the license renewal. In response to the staff's request for additional information, on November 2, 1998, the applicant provided the staff with 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 in additional information 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 describes the technical information related to the systems with component supports at the CCNPP site that are within the scope for license renewal and identified which of those structures and components are subject to an AMR.

2.2.3.1.1 Summary of Component Supports Technical Information in 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 47 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 vessels supports, evaluated in Section 5.18 of Appendix A to the LRA.
- Jet impingement barriers and whip restraints 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 vibrator 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
	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 2.2.3.1.2 of Appendix A to the LRA to determine whether there is reasonable assurance that the applicant has appropriately identified the components 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 7 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 not within the scope of license renewal and, therefore, its component supports were not within 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 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 provided 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)) that 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 identified the piping segments that provide structural support and that are within the scope for license renewal and noted which of those piping segments are subject to an AMR.

2.2.3.2.1 Summary of Technical Information Regarding Piping Segments That Provide Structural Support in the Application

Systems that have safety-related/non-safety-related 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 3.1 of 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 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 identified 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 aging management review (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 CFR54.4(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 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 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 7 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 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.
	• 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 stainless steel 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 stainless steel shell that encloses an aluminum honeycomb material.
	• The SFP platform is a portable work platform 16 ft long x 4 ft 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 stainless steel structural members and can be located along designated walls of the SFP.

	• The SFP storage racks are fabricated of stainless steel 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 stainless steel. 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 stainless steel 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 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 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 stainless steel cables connected to the carriage and through sheaves to its driving winches mounted below the operating floor level. The fuel carrier is mounted on the carriage and is pivoted for tilting by the upending machines.
	• 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 where 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
- Support single failure-proof criteria 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 Updated Final Safety Analysis Report (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 5 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 stainless steel liner, (5) fuel transfer tube stainless steel liner, (6) spent fuel pool reinforced concrete, (7) spent fuel pool stainless steel 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 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 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 scope for 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 scope for 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 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 (HLHC) 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 HLHC 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 stainless steel liner
- fuel transfer tube stainless steel liner
- spent fuel pool reinforced concrete
- spent fuel pool stainless steel liner
- spent fuel pool storage racks, and
- new fuel storage racks

The remaining 48 components, listed in Table 3.2-1 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 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 identified 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 Application

As described in Appendix A to the LRA, the primary containment is designed to withstand an internal pressure of 50 psig, a coincident concrete surface temperature of 276 ºF, and 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 — Provides 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 four 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 three component types for the containment system: (1) air locks and equipment hatch, (2) containment penetrations, and (3) limit switches. Of these three component types, the applicant identified two 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, 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 the application;
- Supports for the steam generators and pressurizer, which are evaluated for the effects of aging in Section 3.1 of the application;
- Supports for the reactor vessel, which are evaluated for the effects of aging in Section 3.2 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 Scope of License Renewal

The staff reviewed Section 5.1, "Containment Structure," of the USAR 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. Based on its review, the staff found that the applicant did not omit anything.

Table 3.3A-1 of the LRA shows that all of the containment structure components that comprise the 37 structural component types within the scope of license renewal that 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 were found not to 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 the LRA. On the basis of the components identified in the referenced tables 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 set forth 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 Aging Management Review

Of 39 device types within the scope of the license renewal rule, 3 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 any electrical/ instrumentation components that should be subject to an AMR. Of the three components, the applicant classified the limit switch as having only an active function and, therefore, not requiring an AMR. One device type, 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 the three electrical/instrumentation device type 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 included 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 L.A. 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 scope 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 the scope of 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 considered 100 percent of the structural and system component types that constitute the CCNPP containment structure and the containment system.

With the exception of the tendon gallery structure, the staff finds that there is reasonable assurance that the applicant has appropriately identified an acceptable scope of structural and system component types for the primary containment structure that are subject to an AMR pursuant to 10 CFR 54.21(a)(1).

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 give 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 is Confirmatory Item 2.2.3.4.2.2-1.

2.2.3.5 Turbine Building Structure

In Section 3.3B, "Turbine Building Structure," of Appendix A to the BGE license renewal application (LRA), BGE described the turbine building and noted the components that are within the scope of license renewal. BGE also noted which of those within-scope components are subject to an aging management review (AMR).

2.2.3.5.1 Summary of Technical Information in 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, BGE described the turbine building, including the conceptual boundaries, and listed the intended functions performed by its structural components. BGE then identifies 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.

BGE 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, BGE developed a generic list of component types for use during the structural component scope task. On the basis of this generic list, BGE determined 24 structural component types for the turbine building (as listed in Table 3.3B-2 of 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 24 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 the 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 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 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. The staff found no omissions by the applicant.

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 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 questioned why the turbine building roof trusses were not listed in Table 3.3B-2 of Appendix A to the LRA. As a result, 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 had not been subjected to an AMR. The applicant stated that the roof trusses are within the scope of license renewal, but are not subject to an AMR because they do not perform an intended function. The staff determined 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 require an AMR.

The staff has reviewed the information in Section 3.3B of Appendix A to the LRA and finds that there is reasonable assurance that the applicant has appropriately identified the structural components subject to 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 describes the technical information related to the intake structure at the CCNPP 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 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 length of the structure.

The intake structure is approximately 90 ft x 385 ft, and is constructed primarily of reinforced concrete. The foundation slab varies in elevation from −26 ft 0 in. to −14 ft 3 in. 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 mils thickness is provided at the exposed face of the exterior walls and below the base slab. Rubber waterstops are also provided at all construction joints up to grade elevation. Subsurface drains are provided to lower the elevation of groundwater around the plant. 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 ft 6 in. 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 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 the 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 Sections 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 final safety analysis report (FSAR), and the content of Section 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 ft 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 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 these 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 under 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 follow:

- The associated pumps are evaluated under the respective systems.
- The fixed bases (normally steel) that support the pumps and connects 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 component support commodity.
- The intake structure 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 the baffle walls to prevent pleasure crafts from entering the intake area. The baffle walls overhangs from the embankment and is 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 licensee.

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 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 intended functions.

The applicant has identified the long-lived and passive structures and components 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 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 describes the technical information related to enclosures for tanks and valves at the CCNPP site that are subject to an AMR for license renewal.

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

The three miscellaneous tank and valve enclosures identified by the applicant as being within the scope of license renewal are 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 the staff 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. Based on 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 the 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 identified the components that are within the scope of license renewal and also identified which of those within-scope components are subject to an AMR.

2.2.3.8.1 Summary of Technical Information in 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:

- Provide structural or functional support or both to safety-related equipment.
- 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.)
- Serve as a pressure boundary or a fission product retention barrier in the event of a design-basis event.
- Serve as a missile barrier (internal or external).
- 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).
- Provide flood protection barrier (internal flooding event).
- 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 prior to issuance of the Unit 1 operating license in 1976, operating experience related to aging mechanisms and their management for the auxiliary building is expected to provide early warning to the applicant for 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 the LRA. A “component support” is the connection between a system, or component within a system, and a plant structural member. Component supports interface with the 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 an 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 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 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 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 is considering whether 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. Until this issue is resolved, it is identified as Open Item 2.2.3.8-1.

In NRC Question No. 3.3.45, the staff asked the applicant to state if any portions of the equipment and floor drainage system (EFTS) 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 EFTS 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 EFTS 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, except for the open item identified above, 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 components 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 applicant should clarify how the component types are grouped such that the discussion in the application and the listing in Table 3.3E-2 are consistent. Nonetheless, 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 aging management review.

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 describes the technical information related to the systems with component supports at the CCNPP site that are within the scope for license renewal and identified which of those structures and components are subject to an AMR.

2.2.3.9.1 Summary of Technical Information in 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 quenched tank. The RCS vent lines from the RPV and the pressurizer also discharge to the quenched 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-in. (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 stainless steel 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-in. (inside diameter) hot leg piping connecting the reactor vessel outlets to the SG inlets, and 30-in. (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 in this evaluation:

- Small tubing and piping that are field run (i.e., instrumentation tubing) and that have no component designators are not evaluated in 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 reviewed in this SER are evaluated in Section 3.1 of Appendix A to the LRA.

Instrumentation and controls covered by the 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 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 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 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 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 Appendix A of the LRA. The RCP and motor-cooling subcomponents are evaluated in this SER out to the connection with the component cooling (CC) system. Included in this evaluation are the SG and pressurizer supports. Component supports, cables, instrument lines, and instruments not identified as RCS components in the RCS scoping results are 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 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, tanks, etc.), 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 (RV); 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, they were not included in the individual system sections. These components are the following:
- 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 in this section.
- 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 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 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, (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 clarifications 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 also 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 as to 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 the 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). Also, its failure would not prevent satisfactory accomplishment of any of the functions identified in 10 CFR 54.4(a)(1). As a result, the applicant correctly determined that the spray head need not be within the scope of license renewal. On the basis of this clarification, the staff agrees with the applicant's conclusion.

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.

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, 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 and describes those that were and were not susceptible to specific ARDMs.

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, BGE 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 does not find any omissions or mistakes in classification (except for the fuses as discussed below) 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 BGE did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 52 components, BGE 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, “Reactor Pressure Vessel and CEDMs/Electrical Systems.”

The following eight device types are evaluated under Section 2.2.3.32, Section 2.2.3.33, and Section 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 categories of fuses and miscellaneous.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 BGE’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, except for the categories of fuses, there is reasonable assurance that BGE 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, BGE (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), that are subject to an aging management review (AMR) for license renewal.

2.2.3.10.1 Summary of Technical Information in the LRA Concerning the RPV & 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 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, BGE 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 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.

Based on the intended functions set forth 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 three that are subject to an AMR. The three device types are 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, they were not included in the individual system sections. These components include the following:

- 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 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 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 accomplished 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 of 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 the applicant to 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 BGE 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 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 the applicant to 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 the LRA and, therefore, was not within the scope of license renewal. The staff concurred with the assessment. NRC Question No. 4.2.3 requested the applicant to clarify whether the component identified in comment (d) of Table 4.2-2 of Section 4.2.1 of 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 the applicant to describe the functions of the core support lug and to 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. Based on 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 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 significant 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 nine 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 under 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 describes the technical information related to the structures and components of the reactor vessel internals (RVI) system at the CCNPP 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 [CS]), and the upper guide structure (UGS) (including the 65 CEA shrouds and incore instrumentation [ICI] guide tubes). The reactor component handling equipment includes the reactor vessel head lifting rig, the RVI lifting rigs, and the surveillance capsule retrieval tool.

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 Updated Final Safety Analysis Report (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 stainless steel 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 CS. The core support assembly is supported by the upper flange of the CSB, which rests on a ledge in the reactor vessel flange. The lower flange of the CSB supports and positions the lower core support structure, which consists of a core support plate (CSP), vertical columns, horizontal beams, and an annular skirt. The weight of the core is supported by the CSP, which transmits the load through the columns to the beams to the skirt to the lower flange of the CSB. The CSP provides support and orientation for the fuel assemblies. The CS, which provides lateral support for the peripheral fuel assemblies, is also supported by the CSP. The lower end of the CSB is restrained radially by six CSB snubbers. 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 functions 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 functions 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), CS, 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 (FAPs), fuel alignment plate/guide lug insert (FP), HDR, ICI thimble support plate (ITSP), ICI thimbles, lower support structure beam assembly (LSSBA), 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 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 discharged with that assembly and since fuel assemblies are replaced after only a few years in the reactor, 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 as the expansion compensating ring in the UFSAR, 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 stating 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 indicates 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 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 an additional 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. As described in Section 4.3 of Appendix A to the LRA, those portions of the RVIs and the associated (supporting) structures and components that fall within the scope of license renewal are also within the scope of license renewal and subject to an AMR. 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 Aging Management Review

According to their function, the RVI structures are determined to perform its 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, BGE (the applicant describes the technical information related to the structures and components of the AFW system at the CCNPP site that are within the scope for license renewal and identified and listed which of those structures and components are subject to an AMR.

2.2.3.12.1 Summary of AFW Technical Information in 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 ºF 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 ºF; 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 provided from the feedwater

system to the engineered safety feature actuation system and the reactor protective system.
- Provide seismic integrity and/or protection of safety-related components.
- 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 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, BGE 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 dated August 21, 1998), and the applicant provided responses to those RAIs by letter dated November 2, 1998.

2.2.3.12.2.1 AFW 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 updated Final Safety Analysis Report (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 the LRA. The staff reviewed the few remaining components of the AFW system 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 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 requested more detailed information from the applicant.

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. 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 concludes 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 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 5.1-1 of Appendix A to the LRA). The staff reviewed the information submitted by the applicant to verify that the grouping was correct. Therefore, 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 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 and are evaluated in this SER. A total of 24 current/pneumatic devices are within the scope of license renewal. Only 8 of these devices are subject to an AMR and are reviewed in this SER. 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 under Section 2.2.3.35, “Instrument Line” of this SER.

The following eight device-types are evaluated under 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, except for fuses.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 RAIs. On the basis of this review, the staff finds that, except for fuses, there is 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 describes the technical information related to the systems with component supports at the CCNPP site that are within the scope for license renewal and identified which of those structures and components of the chemical and volume control system that are subject to an AMR.

2.2.3.13.1 Summary of Technical Information in 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, regeneration 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; and,
- For environmental qualification (10 CFR 50.49)—to maintain functionality of electrical components as prescribed by the environmental qualification program.

Based on the intended functions listed above, the portions of the CVCS that are within the scope of license renewal include all components (electrical, mechanical, and instrumental) 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 all equipment within this boundary is considered a safety-related pressure boundary component.

Based on the intended functions set forth above, 53 device types were listed from the portions of the CVCS that are identified 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. Seventeen of these 25 device types are addressed in Section 5.2 of Appendix A to the LRA, including: 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 (RV), solenoid valve (SV), temperature element (TE), and tank (TK). The remaining eight 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 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 Updated Final Safety Analysis Report (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 applicant-identified portion and, as described below, requested 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 the applicant to specify whether the storage tank and pipe insulation material within the CVCS was within the scope and was subject to an AMR, and if not, to justify excluding these components from the renewal scope. In response, the applicant stated that these insulation materials perform none of the intended functions listed in Appendix A to the LRA and, therefore, are not within the scope of license renewal. The staff reviewed the requirements of the technical specification (TS) to verify the applicant's assertion that the potential age-related degradation of these insulation materials will not affect the system's ability to maintain the required boron concentration. The TS requires that the water temperature be monitored every 24 hours in the safety-related tanks and pipes. As a result, any failure of the heater or excessive heat loss due to degradation of any insulation from these tanks and pipes can be detected in time, and corrective actions can be taken to maintain the required boron concentration and therefore the staff concurs with the licensee in that these insulation materials are not within scope and not subject to an AMR.

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 CVCS component supports 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 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

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 5 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) except for fuses:
- control valve
- solenoid valve
- flow element
- temperature element
- MOV

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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, except for fuses, 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 identified the CC components that are within the scope of license renewal. The applicant also noted which of those within-scope components are subject to an AMR.

2.2.3.14.1 Summary of Technical Information in 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) provides 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; 6 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, they were not included in the individual system sections. These components are:

- 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.
- 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 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 which 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 7 interfacing systems that were not within the scope of license renewal. Of the 7 interfaces, 5 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 at a 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 that there is 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 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 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 5.3-2 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 6 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 finds no significant omissions or mistakes in classification of these components.

The staff agrees with the applicant’s determination, which is consistent with 10 CFR 54.21(a)(1) except for fuses. Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 RAIs. On the basis of this review, the staff finds that, except for the fuses, there is 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 identified the compressed air system components that are within the scope of license renewal. The applicant also noted which of those within-scope 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 consist 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 (LRA Section 5.17) 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 under 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 under 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, i.e., 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; 6 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 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, these common components were not included in the individual system section for compressed air. 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 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 compressed-air system components and supporting structures 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 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 were not 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 provided 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 that there is 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 Aging Management Review

In Section 5.4.1.2 of Appendix A to the LRA, BGE (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 29 device types within the scope of the license renewal rule, 18 device types are electrical / instrumentation components. The staff reviewed the device types that are electrical / instrumentation components to verify that BGE did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 18 components, the applicant classified the following 8 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

The staff agrees with the applicant's determination that these 8 electrical/instrumentation components require moving parts or a change in configuration or properties to perform its intended function except for fuses.

Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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. Verification of the appropriate exclusion basis for solenoid valves in the Compressed Air Section and the Containment Spray System is Confirmatory Item 2.2.3.17.2.2-1.

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 under 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 only perform 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). Structural supports for piping, cabling and other components were evaluated by the applicant in Section 3.1 of 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 only perform the pressure boundary intended function without moving parts or without a change in configuration or properties.

Based on the above evaluation, the staff finds that, with the exception of fuses, there is 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 identified portions of the containment isolation group 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.

2.2.3.16.1 Summary of Technical Information in Application

As described in Appendix A to the LRA, numerous systems have 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 aging management 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 and 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 provided responses to the RAIs.

2.2.3.16.2.1 Containment Isolation Group Within 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, BGE 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 for 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 that the applicant had not omitted anything 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 that there is 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 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 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 identified portions of the CS system 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.

2.2.3.17.1 Summary of Technical Information in 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 5.6-1of 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, they were not discussed in the individual system sections. These components are the following:

- Structural supports for piping, cables, and components that are evaluated for the effects of aging in Section 3.1 of the application, except for the shutdown cooling heat exchanger supports that are addressed in Section 5.6 of the application;
- Electrical control and power cabling, which is evaluated in Section 6.1 of the application; 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 the application.

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 provided responses to those RAIs.

2.2.3.17.2.1 Containment Spray System Within 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 the Appendix A to 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 re-evaluated 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 significant 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 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 determine if there were any structures and components having intended functions that might have been omitted from consideration within the scope of license renewal. Except as described in detail below, the staff found that the applicant had not omitted anything, both with respect to interface boundaries and intended functions, 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 scooping 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 the intended function of fission product removal function adequately dispositioned.

In response to NRC Question No. 5.6.4, regarding exclusion of the emergency dousing function of the CS system from the scope of license renewal, the applicant referenced Section 6.7.2 of the UFSAR, which explains that the dousing system is isolated in Modes 1 through 4. Licensee calculations show that the maximum post-loss-of-coolant accident charcoal bed temperature will not cause iodine desorption or charcoal bed ignition. However, the licensee states that the system is available to provide fire protection to the charcoal beds in order to support certain maintenance activities in Modes 5 and 6. 10 CFR 50.48 guided the staff to evaluate the plants' fire protection features as satisfying the provisions of Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 and reflects this evaluation in the Fire Protection SER. In Section F of Appendix A to BTP APCSB 9.5-1, charcoal filters are identified as needing automatic fixed suppression systems due to their inaccessibility during normal plant operations. Further, Section 4, "Ventilation," states that fire suppression systems should be installed to protect charcoal filters in accordance with Regulatory Guide 1.52. The fixed fire suppression system used in this application consists of the water supply piping and direction nozzles. The staff reviewed the applicant's response and found no new information that would support the licensee's conclusion that the piping and nozzles that provide the emergency dousing function do not meet the scoping requirements of 10 CFR 54.4(a)(3). Until this issue is resolved, it is identified as Open Item 2.2.3.17.2.1-1.

Although not specifically mentioned in Section 5.6.1.2 and Table 5.6-1 of Appendix A to the LRA, 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.

As described above, the staff has reviewed the information in Section 5.6 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 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 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.

Of the device types within the scope of 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. 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.

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 5 device-types are evaluated under 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 significant omissions or mistakes in classification of these components. Based on the applicant’s reasoning, the staff agrees with the applicant’s determination, which is consistent with 10 CFR 54.21(a)(1), except for fuses and solenoid valves.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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. 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 Section(see Section 2.2.3.15.2.2) is Confirmatory Item 2.2.3.17.2.2-1.

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 RAIs. On the basis of its review, the staff finds that, except for the fuses and solenoid valve, 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 identified the DFO system components that are within the scope of license renewal. The applicant also identified which of those within-scope components are subject to an AMR.

2.2.3.18.1 Summary of Technical Information in 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 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 diesel fuel oil 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; aboveground 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, they were not included in the individual system sections. These components are:

- 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 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 BGE application. 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 application, 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 provided 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 that there is 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 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 provided by the applicant to verify that the grouping of the DFO System structures and components were correct. As described in detail below, the staff finds that there is 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 consider 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 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 propertied and that are not subject to replacement based on qualified life or specified time period. Of the 9 electrical/instrumentation components, the applicant classified the following 6 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) except for fuses.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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, except for fuses, 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 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 the 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 identified 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 the following:

- 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 identified that the following typical components are associated with the EDG auxiliaries outside the skid boundary:

- EDG fuel oil day tanks
- EDG fuel oil transfer pumps
- EDG drip tanks
- EDG drip tank pumps
- EDG starting air receivers
- EDG intake/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 identified 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.

On the basis of the intended functions listed above, the applicant identified 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 identified 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 stainless steel 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 identified 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 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. One intended function of the EDG system—providing vital power for safe shutdown in the event of a fire as required by 10 CFR 50.48—was not listed as an intended function by the applicant but was considered by the staff in this evaluation.

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, other than providing vital power in the event of a fire (which did not result in any components being outside the scope of license renewal that should have been within the scope of license renewal), 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 provided in Section 5.8 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 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 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 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 7 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. Based on the applicant's reasoning, the staff agrees with the applicant's determination which is consistent with 10 CFR 54.21(a)(1), except for fuses.

Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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 RAIs. On the basis of its review, the staff finds, except for fuses, 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 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 identified 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.
- 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,” 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 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 those RAIs.

2.2.3.20.2.1 Feedwater System Within 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 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 the application only appeared to 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 the response, the applicant stated that it considers the function of steam generator isolation to include the backup means of stopping FWS flow, i.e., 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 identified 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.

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 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 that there is 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 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 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 5.9-1 of Appendix A to the LRA). The staff reviewed all the information provided by the applicant to verify that the applicant's grouping was correct.

The applicant identified 23 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 23 device types. Of 23 device types within the scope of license renewal rule, 19 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 19 components, the applicant classified the following 13 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

Two device types, SG level transmitter and SG pressure transmitter, are either subject to periodic replacement or are evaluated in another AMR. Eight of the twenty SG level transmitters are included 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.

Two device types, control/power cabling and instrument tubing/valves, are evaluated in Section 2.2.3.32, "Cables;" 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) except for fuses.

Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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 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 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, except for fuses, that there is 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 identified the systems and the components credited with performing fire protection (FP) functions that are within the scope of license renewal. It also identified which of those components within scope 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 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 under 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. The applicant's current licensing basis (CLB) requires compliance with 10 CFR Part 50 (Appendix R, Sections III.G, III.J, III.L, and III.O). 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 identified 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 of 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
- 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 thirteen electrical systems with components that perform FP-intended functions. Those systems require no futher evaluation in Section 5.10 since 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, they were not included in the individual systems and structure 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 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.
- 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) states 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 in 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 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 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 system and structure 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

System	LRA Section*	System	LRA Section*
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 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

System	LRA Section *	System	LRA Section*
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 which 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 is being tracked by Open Item No. 2.2.3.17-1 and further discussion is provided in Section 2.2.3.17 to this safety evaluation report.

As described above, the staff has reviewed the information submitted in Section 5.10 of Appendix A to the LRA and the additional submitted by the applicant in response to the staff's RAIs. On the basis of its review, with the one exception noted above, the staff concludes that 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 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 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 inother 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 PWSTs 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 an SS intended function	Maintain pressure-retaining capability 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)
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)
Demin. Water & 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)

System	NSR Portion of System Within the Scope of LR and Subject to an AMR	Passive FP-intended Function (not addressed in other evaluations)
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)

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. Structures and components were identified by the applicant 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 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, BGE (the applicant) identified portions of the ABHVS 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.

2.2.3.22.1 Summary of Technical Information in 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 prior to 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 ºF in summer and a minimum of 60 ºF 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 ºF 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 ºF or below. During the emergency mode of operation, redundant fans circulate air between the AFW pump room and the EDG room through a system of connecting ductwork, and the rooms are maintained at 120 ºF 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 line penetration area is pressurized and provided with outside air as the cooling medium, and the excess air flows out through the open safety vent to the roof.

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. The saltwater system provides cooling to the cooling unit.

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 in the fuel handling area air is diverted through charcoal filters after it leaves the HEPA filters to minimize the release of radioactive material release 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 ºF 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 contamination 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 §54.4(a)(3):

- For fire protection (10 CFR 50.48) — To provide alternate ventilation to the AFW pump room during a fire
- 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 (1), filter, gravity damper, manual damper, hand valve (1 and 2), heat exchanger (1), and pressure differential indicator (2). The applicant further 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 the application;
- Electrical control and power cabling, which is evaluated in Section 6.1 of the application; and
- Process and instrument tubing and tubing supports, which are all evaluated in

Section 6.4 of the application.

2.2.3.22.2 Staff Evaluation

The staff reviewed Section 5.11A of the LRA to determine whether there is reasonable assurance that the applicant has appropriately idetnified 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 RAI.

2.2.3.22.2.1 Auxiliary Building Heating and Ventilation System Within 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 the 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 provided Figure 5.11A-1 showing the scoping boundaries for the ABHVS. On the basis of the applicant’s response, the staff agrees that this figure identifies 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 response to the staff’s RAI. On the basis of that review, the staff finds that there is reasonable assurance concludes 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 Aging Management Review

On the basis of the intended system functions listed above, the applicant emphasized that the portions of the auxiliary building H&V 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 auxiliary building H&V 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 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
- pressure converter (relay)
- temperature controller
- position switch
- temperature element
- temperature switch
- motor operator
- temperature indicating controller
- position indicating lamp
- position controller
- temperature transmitter
- control valve

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.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

The staff has reviewed the information included in Section 5.11A of Appendix A to the LRA and additional information submitted by the applicant in response to the staff RAIs. On the basis of this review, the staff finds that, except for fuses, 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).

2.2.3.23 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 identified 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 within-scope components are subject to an AMR.

2.2.3.23.1 Summary of Technical Information in 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 conditions 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 lists 38 device types that are within the scope of license renewal. They also identify 3 addition primary containment H&V system device types (panels, cables and instrument lines, that are evaluated by BGE 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 included in the separate commodity reports that 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 that are evaluated for the effects of aging in Section 3.1 of the application;
- Electrical control and power cabling that is evaluated in Section 6.1 of the application; 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 the application.

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 letter dated September 2, 1998), and by letter dated November 16, 1998, the applicant provided responses to those RAIs.

2.2.3.23.2.1 Primary Containment Heating and Ventilation System Within 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 of 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 the rule.

Section 6.5.4 of the UFSAR describes piping that transfers the condensate leaving the coils to the containment sump. The staff asked (NRC Question No. 5.11.4) the applicant 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 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 that 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 with 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. The staff is 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; therefore, this is Open Item 2.2.3.23.2.1-1.

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. Except for the open item identified in this section of the SER, on the basis of the review stated above, the staff finds that there is 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 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 lists 38 device types that are within the scope of license renewal. They also identify 3 addition primary containment H&V system device types (panels, cables and instrument lines, that are evaluated by BGE in Sections 6.1, 6.2, and 6.5 of Appendix A to the LRA. Of the 41 device types, 21 were determined to perform its intended function with moving parts or with a change in configuration or properties and not require an AMR. Eight device types were evaluated in other sections of the LRA. The remaining 12 device types were determined to require an AMR and included: check valve, control valve, damper, HVAC duct, fan, filter, gravity damper, piping (Code HB), hand valve, heat exchanger, motor-operated valve, and solenoid valve.

The staff reviewed all the information provided 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 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 action 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
- pressure indicator
- pressure indicating differential indicator
- alarm
- relay
- temperature element
- temperature indicator
- power supply
- position indicating lamp
- position switch
- 480V motor (feed from MCC)

The staff reviewed and agrees with the applicant's determination that these device types perform its functions with moving parts or with a change in configuration or properties with the exception of fuses. Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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

Eight of the 11 device types (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 nine 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 had 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, 5.11.7]) from an AMR. BGE explained that such components were excluded for one of the following reasons: (1) they were active components, and were not within the scope of the license renewal, (2) they were not safety-related, and did not impact the functioning 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 applicants justification and determined that the applicant’s justification was consistent with the requirements under 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 under 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, with the exception of fuses, 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, BGE (the applicant) identified portions of the CRHVACS and DGBHVACS and the components therein that are within the scope of license renewal and noted which of those within-scope components are subject to an AMR.

2.2.3.24.1 Summary of Technical Information in 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, BGE 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 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.

BGE 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 BGE as within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument) and their supports. BGE identified a total of 44 device types as within the scope of license renewal. Of these 44 device types, BGE identified 9 that are subject to an AMR. The 9 device types are: analyzer element, gravity damper, damper, heat exchanger, HVAC duct, hand valve (1), fan, temperature transmitter, and filter. BGE further indicated that maintenance of the CRHVACS 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 9 device types subject to an AMR was considered.

BGE 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, 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 the application;
- Electrical control and power cabling, which is evaluated in Section 6.1 of the application; and
- Process and instrument tubing and tubing supports, which are all evaluated in Section 6.4 of the application.

2.2.3.24.2 Staff Evaluation

The staff reviewed Section 5.11C of 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 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.

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 the 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 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 BGE 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, BGE sent Figures 5.11C-1, -2, -3 depicting the scoping boundaries for the CRHVACS and DGBHVACS. On the basis of BGE'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 Aging Management Review

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

BGE identified a total of 44 device types of the control room HVAC system as within the scope of license renewal. Of these 44 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. 9 device types are subject to an AMR: analyzer element, damper, HVAC duct, fan, filter, gravity damper, heat exchanger, hand valve, 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 license renewal rule, 23 device types are identified as electrical/instrumentation components. The staff reviewed 31 device types to verify that BGE did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 31 components, BGE classified the following 23 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-Vdc motor
- position switch
- relay

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

Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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

BGE 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, BGE 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 HVAC system, in Section 5.11C.1.4 of Appendix A to the LRA, BGE explained that the newly installed diesel generator buildings 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 states 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 HVAC system. However, the applicant should demonstrate that the environmental conditions (temperature, moisture content in the air, etc.) and hardware configurations of the diesel generator buildings HVAC system are similar to environmental conditions and hardware configuration in the control room to arrive at such a conclusion (see confirmatory item 3.6.2.1.4-1). This is addressed in Section 3.6.2.1.4 in 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 RAIs. On the basis of this review, the staff finds that, except for fuses, 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. The applicant also 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 identified 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 due to its containment penetration.

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 its entering 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 its entering 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 identified 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 includes 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 includes 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 alternating current 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 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, 8 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.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 inc 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 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 to be within the scope of license renewal that the applicant did not identify.

The staff 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 included 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 identified 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 agrees with the applicant’s approach and the staff 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 Safety Evaluation Report.

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 provided 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 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 or 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). The staff reviewed the information submitted by the applicant to verify that the grouping was correct and found no significant omissions in classification. Therefore, the staff finds that there is 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 BGE did not omit any electrical/instrumentation components that should be subject to an AMR. Of the 24 components, BGE 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 7 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

The following 6 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

With the exception of fuses, 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). Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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. Some device types appear more than once in these tables. The staff finds that BGE included all of these device types as subject to an AMR, which is acceptable.

The staff has reviewed the information in Section 5.12 of Appendix A to the LRA. On the basis of its review of selected structures and components, the staff finds that, except for fuses, that there is 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 describes the technical information related to the structures and components of the NSSS sampling system at the CCNPP site that are within the scope of license renewal and subject to an AMR.

2.2.3.26.1 Summary of Technical Information in 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 5 subsystems: reactor coolant sampling, steam generator blowdown sampling, radioactive miscellaneous waste sampling, gas analyzing sampling, and post-accident sampling.

•	<u>Reactor Coolant Sampling</u>
	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 stainless steel 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.
•	<u>Steam Generator Blowdown Sampling</u>
	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.
•	<u>Radioactive Miscellaneous Waste Sampling</u>

•	<u>Reactor Coolant Sampling</u>
	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.
•	<u>Gas Analyzing Sampling</u>
	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.
•	<u>Post-Accident Sampling</u>

•	Reactor Coolant 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 application describes 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 per 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 includes all safety-related components (electrical, mechanical, and instrument) and their supports that are within the scope of license renewal. 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 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). 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.

- 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 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;
- 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.

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
- circuit breaker
- voltage/current device (relay)
- 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 8 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) except for fuses.

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. Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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, BGE (the applicant) identified portions of the RMS and their components that are within the scope of license renewal and identified which of those “within scope” components are subject to an AMR.

2.2.3.27.1 Summary of Technical Information in 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 such 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. 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 system (SRW) 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 of 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 Section54.4(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 BGE 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, BGE 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).

BGE 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 the application.
- electrical cabling, which is evaluated in Section 6.1 of the application.
- instrument tubing and piping and their associated fittings, instrument valves, and supports, which are all evaluated in Section 6.4 of the application.

2.2.3.27.2 Staff Evaluation

The staff reviewed Section 5.14 of 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 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 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 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. Based on this review, the staff found no significant omissions by the applicant except the item discussed below. 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 the 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 the 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 the above reason 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 significant 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 provided 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 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 the 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, sixteen device types were determined to have passive intended functions and therefore require an AMR. Of the 16 device types requiring an AMR, 12 are electrical/instrumentation components. The following 5 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 HVAC," Section 2.2.3.32, "Cables," and Section 2.2.3.35, "Instrument Lines," of this SER.

- CCS radiator element
- SWS radiator element
- control room ventilation radiator 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 portions of the RMS in the scope of license renewal as required under 10 CFR 54.4.(a)(1), and 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 describes the technical information related to the structures and components of the safety injection (SI) system at the CCNPP 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 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 º 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 (RVs), 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.
- 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 ºF.

- For environment 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.
- 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.

Based on the intended functions described in Appendix A of 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 an 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 an 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 containment, through the SDC header return isolation MOV outside 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 stainless steel 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, RVs, solenoid-operated valves in instrument air supply piping) and their supports are also within the scope of license renewal for the SI system

Based on the intended functions set forth 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 (RV), 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 include the following:

- 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 of 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 of 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 the submittal. 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 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 applicant-identified portion and, as described below, requested the applicant to 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 the rule.

After completing the initial review, by letter dated September 2, 1998, the staff issued requests for additional information (RAIs) regarding the SI system. By letters dated November 9, 1998, the applicant's responded to those RAIs. 10 CFR 54.21(a)(1) states that valve bodies are passive. Page 5.15-12 of Appendix A to the LRA lists solenoid valves among 29 device types identified as having only active functions. NRC Question No. 5.15.1 requested the applicant to clarify why solenoid valves were determined to have only active functions. 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, does 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. The air provided to control valve operating schemes in the SI system is non-safety-related. 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.

Page 6.3-3 (Revision 18) of the CCNPP 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 requested the applicant to indicate if this valve is subject to an AMR, and if so, to cross-reference where this is addressed in Appendix A to the LRA; if not, to provide the basis for 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 CCNPP UFSAR indicates that the containment sump suctions are enclosed by particulate screens. NRC Question No. 5.15.3 requests the applicant to clarify whether these screens are subject to an AMR, and if so, to cross-reference where they are addressed in Appendix A to the LRA; if not, to provide the basis for exclusion. The applicant stated in 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 that there is 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 Aging Management Review

The applicant describes the components of the safety injection (SI) system that are subject to an AMR in Section 5.15.1.3 of Appendix A the LRA. The applicant divided structures and components within the scope of the 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 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 except for fuses, which is discussed below. Therefore, the staff finds that there is 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 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 9 device types are evaluated under 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. components

The following 5 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 properties 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) except for fuses.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 the 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 (RV),
- Tank.

As discussed above, the staff has reviewed the information provided in Section 5.15 of Appendix A to Appendix A to the LRA and the additional information provided by the applicant in response to the staff's RAIs. Based on that review, the staff finds that, except for fuses which are discussed in Section 2.2.3.33, there is 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. The applicant also identified which of those within-scope components are subject to an AMR.

2.2.3.29.1 Summary of Technical Information in 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 water system (ECCS) pump room coolers, as required by General Design Criteria 44 of 10 CFR Part 50, Appendix A.

The SW system for each unit consists of two subsystems. Each subsystem provides SW to a 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 equipment qualification—Maintain functionality of electrical components as addressed by the Equipment 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.
- 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 the application.

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 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 SRW 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 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 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 the license renewal. The applicant categorized those structures and components into device types not subject to an AMR and device types subject to an AMR listed in Table 5.16-1 of Appendix A to the LRA. The staff reviewed the information provided by the applicant to verify that the applicant's grouping was correct. As described in detail below, the staff finds that there is 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, 25 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 any electrical/ instrumentation components that should be subject to an AMR. Of the 25 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 7 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 4 electrical/instrumentation components were classified as subject to an AMR (only pressure boundary/body):

- control valve
- current to pneumatic transducer
- solenoid valve
- temperature indicator

Some of the current to pneumatic transmitters and solenoid valves are periodically replacement 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.

Fuses are addressed in Section 2.2.3.33, "Electrical Commodities," of this SER.

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
- Hand valves
- Heat exchangers
- Pump/driver assemblies
- Relief valves
- Temperature test points

2.2.3.29.3 Review Findings for the Saltwater System

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, except for fuses, there is reasonable assurance that the applicant has appropriately identified the portions of the Saltwater system that is within the scope of license renewal as required under 10 CFR 54.4(a)(1), and 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 identified components and associated structures of the closed-loop SRW system that are within the scope of license renewal and identified which of those within the scope of license renewal components are subject to an AMR.

2.2.3.30.1 Summary of Technical Information in 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 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 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 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 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. However, 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), except for the item identified below, 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 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 [per 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 because it only 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 is the staff’s opinion that the information in the cited references reinforces 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). Until this issue is resolved it is identified as Open Item 2.2.3.30-1.

As described above, the staff has reviewed the information provided in Section 5.17 of Appendix A to the LRA and the additional information provided by the applicant in response to the staff’s

RAIs. Based on that review and upon the applicant's response to the staff's RAIs, except for the open item identified above, the staff finds that there is 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 Aging Management Review

In Section 5.17.1.2 of 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"). The staff reviewed the information provided 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 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 components, the applicant classified 16 of these components as having only active functions and therefore not requiring an AMR. These components types are:

- 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 moto
- 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

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

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 Aging Management Review,” of this SER.

The remaining seven device types are piping and mechanical components that perform passive functions and include the following:

- Piping
- Check valves
- Flow orifices
- Hand valves
- Pump/drain assemblies
- Relief valves
- Tanks

The staff agrees with the applicant’s inclusion of these devices in the AMR program.

The staff has reviewed the information provided in Section 5.17 of Appendix A to the LRA and has determined that there is reasonable assurance that, with the exception of fuses, 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 CCNPP site that are within scope for license renewal and identified which of those structures and components are subject to an aging management review (AMR).

2.2.3.31.1 Summary of SFPCS Technical Information in 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.

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 are 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 exchangers 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 for 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, they were not discussed in the individual system sections. These components are the following:

- Structural supports for piping, cables, and components 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 per 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 Questions No. 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 applicants response and agreed that the components either performed no intended function and were not withing 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 that there is 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 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 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 or 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 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 5.18-2, “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 significant omissions in classification. Therefore, the staff finds that there is 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 8 components 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.

- 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 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), with the exception of fuses and temperature switches.

Fuses are addressed in Section 2.2.3.33, “Electrical Commodities,” of this SER.

As indicated above, the applicant classified temperature switch as subject to an AMR. Because temperature switch performs its intended function by changing configuration or properties, it is an active device and need not be 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 that there is reasonable assurance that the applicant has appropriately identified the structures and components within the scope of license renewal and are subject to an AMR for the SFPCS to meet the requirements stated in 10 CFR 54.21(a)(1), with the exception of fuses.

2.2.3.32 Cables

In Section 6.1, “Cables,” of Appendix A to the LRA, the applicant described cables that were evaluated as a “commodity” in accordance with the applicant’s IPA methodology described in Section 2.0 of the renewal application that are subject to an aging management review (AMR) for license renewal.

2.2.3.32.1 Summary of Technical Information in 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 bindings 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 90ºC 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 (IR) reduction for EPR/XLPE/XLPO non-EQ cables in instrumentation service, which are sensitive to reduction in cable IR

	Group 1—Includes thermal aging for EPR/XLPE/XLPO non-EQ cables in power and control service, which are routed without maintained spacing.
	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 per 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 which 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 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 not within the scope of license renewal are excluded if they met any of the following conditions:

- Cable schemes associated with systems having no license renewal functions;
- Cable schemes which are non-safety related and are associated with systems which do not support any non-safety-related license renewal functions;
- Cable schemes for annunciator circuits which do not support any events regulated under 10 CFR 54.4(a)(3);
- Cable schemes which 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 provided by the applicant in response to the staff's RAIs. On the basis of the review of cables as a commodity group, the staff finds that there is 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 Aging Management Review

In the second step of the staff 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 or properties and are not subject to replacement on the basis of a qualified life or specified time period. However, internal panel wiring which is within the scope of license renewal was properly excluded from an AMR on the basis that it is not exposed to high temperature or high radiation levels and aging which could affect the functionality of the wiring during the period of extended operation is not considered plausible. Therefore, the staff concluded that 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 provided by the applicant in response to the staff RAIs. On the basis of the staff review of cables, that have been evaluated as a "commodity," the staff has determined that 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 identified those systems containing electrical commodities that are within the scope for license renewal and identified which components within the commodity group are subject to an AMR.

2.2.3.33.1 Summary of Technical Information Regarding Electrical Commodities 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 aging management 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, and
- 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, and
- 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 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 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 identified 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 did not find any omissions of safety-related systems from Table 6.2-1.

On the basis of its review, the staff finds that there is 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 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 or 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 the 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 information to verify that the applicant's identification was correct. As described in detail below, the staff finds that the applicant has not omitted anything significant or made any mistake in classification except for the open item discussed below. Therefore, the staff finds that except for the open item, there is reasonable assurance that the applicant has identified the electrical structural enclosures/supports and the enclosure subcomponents subject to an AMR for the electrical commodities.

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) (except for the open item discussed below).

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").

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. This is Open Item 2.2.3.33.2.2-1.

The staff is addressing the categorization of fuses in a generic position. The resolution of this issue will be reported in this section.

The staff has reviewed the information in Section 6.2 of Appendix A to the LRA and additional information submitted by the applicant in response to the staff RAIs. Except as discussed in the open item above, 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 had been evaluated in accordance with the applicant's IPA methodology described in Section 2.0 of Appendix A to the LRA that is subject to an AMR for license renewal.

2.2.3.34.1 Summary of Technical Information in the Application

Section 6.3 of Appendix A to the LRA 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 further an AMR. 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 8 were determined to be subject to an AMR.

The following EQ devices are within the scope of license renewal include:

- cables (CBL)
- seal (SEAL)
- junction box (WRNMS)
- core exit thermocouple system (RI)
- containment penetration assembly (PEN)
- solenoid valve (SV)
- terminal block (TB)
- reactor level vessel monitoring system in-core assembly (TP)

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 per 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 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 with qualified lives greater than or equal to 40 years were included in the list subject to an AMR in accordance with 10 CFR 54.4(a)(3). On the basis of the staff 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 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 or 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 include cables, seals, junction boxes, solenoid valves, terminal blocks, core exit thermoncouple system, containment penetration assembly, 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 identified those systems containing instrument lines that are within the scope for license renewal and identified those components that are subject to an AMR.

2.2.3.35.1 Summary of Technical Information Regarding Instrument Lines 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 the CCNPP IPA methodology (described in Section 2.0 of Appendix A to the LRA) to determine which systems and components are within the scope for 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 of 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 (NSSS) are evaluated in Section 5.13 of Appendix A to the LRA. NSSS 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 may exceed 10 CFR Part 100 limits, or maintain safety-related system boundaries to limit system leakage are within scope of license renewal in accordance with 10 CFR 54.4(a)(1) and (2). The applicant did not identify any intended function under 10 CFR 54.4(a)(3), other than maintenance of the system pressure boundary.

Instruments 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 their final safety evaluation of the applicant's IPA methodology the position that the functional degradation resulting from the affects 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, BGE concluded that the following remaining instrument line components are subject to an AMR:
- small-bore piping and tubing,
- hand valves,
- non-pressure-sensing instruments, and
- 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 per 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 intended functions described in 10 CFR 54.4(b) 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 that there is 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 Aging Management Review

In Section 6.4.1.1 of the application, BGE defined the category "instrument line" as the components located downstream of the process root valves to the process line. BGE 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 the license renewal and included in the instrument Lines Commodity Evaluation (ILCE). BGE 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 significant omissions or mistakes in classification by the applicant.

The staff reviewed the instrument lines and associated mechanical and electrical/ instrumentation components to verify that BGE 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, etc.) 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 which have passive intended function of maintaining the system pressure boundary. The connected instruments would normally be classified as subject to an AMR due their passive intended function. However, BGE 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). BGE 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. BGE 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)(i).

The staff reviewed the information provided in Section 6.4 of Appendix A to the LRA and additional information provided by the applicant in response to the staff RAIs. Based on this instrument line commodity review, the staff has determined that 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 set forth in 10 CFR 54.21(a)(1).

2.2.4 Conclusions

The staff has reviewed the information included 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 that there are open items. The staff has determined that, on favorable resolution of the open items identified in Chapter 2 of this SER, it will be able to conclude that 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).

2.2.4 Conclusions

The staff has reviewed the information included 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 that there are open items. These open items are discussed in Section 2.2.1.1 of this SER. The staff has determined that, on favorable resolution of the open items identified in Section 2.2.1.1 of this SER, it will be able to conclude that there is reasonable assurance that the applicant has identified and listed those structures and components subject to AMR to meet the requirements of 10 CFR 54.21(a)(1).

3 Aging Management Review

Section 3 of this SER provides the staff's evaluation of BGE's (the applicant's) aging management review. 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, as will be reflected in a subsequent revision to this report. In addition, improved guidance is being developed for updating the contents of FSARs under 10 CFR 50.71(e). Therefore, the resolution of the information that needs to be added to the FSAR will be addressed after the other open and confirmatory items are resolved, prior to issuance of a renewed license. The content of the FSAR will be tracked as Open Item 3.0-1.

The applicant has included some components that perform their intended function with moving parts or with a change in configuration or properties in its aging management review. 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 provide 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 provide 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 the applicant's benefit. Therefore, 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 CCNPP nuclear steam supply system (NSSS) and has developed the fatigue monitoring program (FMP) to manage the effects of fatigue for NSSS components. The FMP is discussed in Sections 4.1, 4.2, 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 of this SER.

3.1.1.2 Summary of Technical Information in Application

As described in Sections 4.1, 4.2, 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 six 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 CCNPP. 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 Calvert Cliffs Nuclear Power Plant (CCNPP) 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. An evaluation of cyclic thermal stratification by the applicant 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 on a periodic basis. In Section 4.1 of Appendix A to the LRA, the applicant described different 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 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 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 timeliness of FMP corrective actions.

The FMP relies on the sampling of critical plant transients for selected NSSS components and the SG FW nozzles to manage fatigue. 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. However, the staff has identified several open items regarding the applicant's screening of components to be included in the FMP. The open items regarding the FMP include those identified in Sections 3.2, 3.3, and 3.9 of this SER. These open items must be resolved in order for the staff to conclude 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, to be an adequate program to monitor the effects of low-cycle fatigue at CCNPP. However, the resolution of the open items concerning the FMP, identified in Sections 3.2, 3.3, and 3.9 of this SER, is necessary in order for the staff to conclude 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 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:

<u>Primary water</u>
- RCS
- CVCS
- Containment spray system (CSS)
- Nuclear steam supply sampling system
- SI system
- Spent fuel pool cooling system (SFPCS)

<u>Secondary water</u>
- Auxiliary feedwater system (AFS)
- FWS
- Main steam system
- SG system
- Extraction steam system
- Nitrogen and hydrogen systems

<u>Component cooling and service water</u>
- 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, (10) and 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:

- Chemistry program, CCNPP administrative procedure CH-1, Revision 1 (existing program),
- Specification and surveillance primary systems, CCNPP technical procedure CP-204, Revision 7 (existing program),
- Specifications and surveillance component cooling/service water, CCNPP technical procedure CP-206, Revision 1 (existing program),
- Specifications and surveillance: secondary chemistry, CCNPP technical procedure CP-217, Revision 5 (existing program),
- Specifications and surveillance—demineralizer water, safety battery water, and well water systems, CCNPP technical procedure CP-202, Revision 5 (existing program),
- Make-up demineralizer water system, CCNPP procedure CP-410 (existing program),
- Monitoring radioactivity in systems normally uncontaminated, CCNPP technical procedure CP-224, Revision 4 (existing program), and

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, and component cooling and service water.

The staff notes that the evaluation of aging effects, or ARDMs, identified by the applicant, is discussed by the staff in a system-by-system basis separately in this SER. Also, the applicant's Chemistry Program is not a stand-alone program. The applicant relies on many other AMPs to manage these ARDMs for these systems. The staff's evaluation of these other programs may be found in the systems sections of this SER.

The applicant's program for controlling primary water chemistry is based on CCNPP 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 pump casing in the SFPCS. The staff concludes that the applicant's programs for control 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 be able to control most of the ARDMs in the primary system.

The applicant's program for controlling secondary water chemistry is based on CCNPP 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 have 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 three ARDMs: (1) crevice corrosion, (2) general corrosion, and (3) pitting. These three ARDMs occur mostly in components made from carbon steel 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 control of 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 CCNPP 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 control of 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 aging effects caused by ARDMs in these systems.

3.1.2.4 Conclusions

The staff has reviewed the information included 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 address 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 this plausible aging degradation mechanism 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 applied the structure and system walkdown procedure MN-1-319 (formerly plant engineering guideline PEG-7) as one of its aging management programs. 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 (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 reporting/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 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 CCNPP 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/schedule.

Walkdowns could be conducted for any of the following 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 cracks.

The LRA states that a performance assessment will be performed on each structure and system at least once every six 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 six years. Structure and system walkdowns may also be performed as required for reasons such 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 set forth 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 structures, systems, and components 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 aging management review. The staff 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 aging management programs for license renewal satisfy Element 7 (corrective actions), Element 8 (confirmation process), and Element 9 (administrative controls). 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 six 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 dynamic. Dynamic degradation would result in an initiation of the IR corrective action process. An example of dynamic 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 follow-up 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 structures, systems, and components (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 of the system engineer and other responsible personnel to be an acceptable method to evaluate 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, is an oversight. As such, the structure walkdown reports will be modified to detect the aging effects of reinforced-concrete structures. This is Confirmatory Item 3.1.3.3-1.

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 CCNPP 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 credits 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”; 5.10, “Fire Protection”; 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.” The applicant also credits 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 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 credits 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 conduct visual inspections of borated systems looking for leaks. 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 affected component surfaces) mitigates the effects of concentrated boric acid corrosion. The program also requires engineering evaluation of the affected component(s) for an assessment of the 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 containment and in the auxiliary building as soon as possible after attaining hot standby condition. The specific locations include carbon steel bolting on Class 1 valves, valves in systems containing borated water (which could leak onto Class 1 carbon steel components), and components that are the subject of IR where borated water leakage has been 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 applicant placed the RV head penetrations 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 applicant placed the RCS 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 applicant placed the RPV 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 applicant placed the CVCS 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 applicant placed the MOVs in the containment normal sump drain lines 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 applicant placed the CSS 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 this system. The BACI program as its 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 applicant placed the NSSS sampling system components containing borated water 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 applicant placed the SI system 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 applicant placed the SFPCS 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 corrosion 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/mitigative 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 aging management review. 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 aging management programs 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 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, the applicant responded, in part, to the staff's RAI.

<u>Program Scope</u>

With one exception, 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. The one exception is for Section 3.2. In that section, 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. The staff's understanding of the BACI program is that it does not provide for removing interference; thus, it is unclear how the applicant is managing this potential aging issue. This is Open Item 3.1.4.3-1. 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 is Confirmatory Item 3.1.4.3-1.

Preventive/Mitigative Actions

The staff finds the mitigative actions required by the BACI program acceptable because of removal of concentrated boric acid and elimination of borated water leakage mitigates 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 corrosion, SCC), there are no mitigative actions in the BACI program. For these ARDMs, the applicant relies on conditioning 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 staffs 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 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 in./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"; 5.10, "Fire Protection"; 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. Except for the open items identified in this SER section, 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 the 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. The four phases of the maintenance strategy used by the applicant are (1) discovery, (2) assessment/analysis, (3) corrective action, and (4) confirmation/documentation.

3.1.5.2 Summary of Technical Information in 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 structures, systems and components are maintained consistent with the CLB.

The applicant proposed to use a site expert panel consisting of (1) an engineer with expertise in aging evaluation, (2) a system engineer, (3) appropriate plant program managers/technical area specialists, and (4) an engineer with expertise in aging management implementation to select the appropriate method for detecting aging effects. 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, ARDIs 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 IR 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 at CCNPP is necessary.

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 aging management programs on the program elements rather than on the details of specific plant procedures. To determine whether the applicant aging management programs 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. The staff finds this program approach acceptable. However, 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" 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, such that any changes to the programs or activities that may affect their effectiveness in managing aging can be appropriately controlled. This is Confirmatory Item 3.1.5.3-1.

3.1.5.4 Conclusions

The staff concludes that adequate information will exist 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 relies 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 license renewal application: 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 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 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 provided 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 expansion criteria to follow 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. 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 identified 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. A brief description of the ARDI purpose for each system is provided below.

For the reactor vessels internals (RVI) system (Section 4.3), the applicant identified 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 occurring or, if occurring, 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 be 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 ARDIs at the most susceptible locations in the AFW system to verify that cavitation erosion 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 ARDIs 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 due to 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 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 performs 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 alloy steel 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 CCS relief valves. For those CVCS 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. Normally, the instrument air (IA) system supplies the air for CAS components. The applicant minimizes moisture in the IA system through preventive maintenance procedures. The applicant also credits testing of CAS containment isolation valves with the discovery of general corrosion; these valves are included in the applicant's LLRT program. To verify the effectiveness of these programs and to ensure that general corrosion of the internal surfaces of the CAS components is not occurring for those portions of the CAS outside the scope of the preventive maintenance (PM) and LLRT programs, the applicant plans to perform ARDIs.

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 performs 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 corrosion of the CI group components exposed to water and gas is not occurring. 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. 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 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 preventive maintenance procedure (which performs 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 identifies 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 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 preventive maintenance 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 duct 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 duct 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 components 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 on 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. 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 these programs, the applicant plans to perform an ARDI. 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. 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. 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. 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 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. 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 rubber-lined SW components because the rubber 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 rubber-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 rubber 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 rubber 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 and alloy steel 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 radiation levels, 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 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

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 aging management review 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 aging management review. The staff's evaluation of the applicant's corrective action program is set forth 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 aging management programs 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, 5.5, 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 more detail pertaining to ARDIs. By letter dated November 12, 1998, the applicant responded, in part, to the staff's RAI. The applicant provided 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. The applicant provided appropriate expansion criteria. The staff finds the applicant's use of this program acceptable, except for those cases in which it appears obvious to the staff that regular, periodic inspections are needed. These instances for each affected system are discussed in SER Section 3.1.6.2, and are identified as Open Item 3.1.6.3-1.

- 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. The staff notes that a one-time ARDI is not sufficient to verify the condition of protective coatings for the period of extended operation. Regular, periodic inspections need to be performed.
- The applicant identified general corrosion as a plausible ARDM affecting the external surfaces of carbon and alloy steel 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 staff notes that a one-time ARDI is not sufficient to verify the condition of protective coatings for the period of extended operation. Regular, periodic inspections need to be performed.
- 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. 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 staff notes that a one-time ARDI is not sufficient to verify that corrosion is not being caused by boric acid leakage for the period of extended operation. Regular, periodic inspections need to be performed.
- For those rubber-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 rubber lining and to verify that corrosion is not occurring. The staff notes that a one-time ARDI is not sufficient to verify that corrosion is not occurring as a result of the degradation of rubber lining for the period of extended operation. Regular, periodic inspections need to be performed.
- The applicant 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 radiation levels, 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 staff notes that a ARDI is not sufficient to verify that corrosion due to boric acid leakage is not occurring for the period of extended operation. Regular, periodic inspections need to be performed.

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 to be 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 provide the staff with the ARDI schedule other than to state that ARDIs are planned to be completed before the end of the current operating license. 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 current operating license expires. 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 provided 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 as included in Sections 4.3, 5.1, 5.2, 5.3, 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 provided during a public meeting. Except for the open item identified in this SER section, on the basis of the staff’s review as stated above, the staff concludes that the applicant has demonstrated that the ARDIs are and 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.

Upon satisfactory closure of the open items discussed in this SER, 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, Internals and Reactor Coolant System

3.2.1 Introduction

BGE (the applicant) described its aging management review (AMR) of the reactor vessel, reactor vessel internals, and reactor coolant system (collectively called RVIC) for license renewal in three separate sections of its license renewal application (LRA): Section 4.1, “Reactor Coolant System”; Section 4.2, “Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System”; and Section 4.3, “Reactor Vessel Internals 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 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 describes 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, 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 describes the RPV. The RPV, which houses the reactor core and its supporting structures, is connected to the RCS piping. The RPVs are comprised of a removable head with multiple penetrations; four primary coolant inlet nozzles; two primary coolant outlet nozzles; upper, intermediate, and lower shell courses; and a bottom head and vessel supports. Each vessel is approximately 503.75 in. high, 172 in. in 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 describes 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, generic 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 pitting.

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 technical procedure RCS-10, “Pressurizer Manway Cover Removal and Installation,” for discovering wear on pressurizer components
- Existing CCNPP technical procedures SG-1, SG-2, SG-5, SG-6, and SG-20 for detecting wear and corrosion on SG manway cover closure and seating surfaces, secondary handhold closure surfaces, and primary manway flange seating surfaces
- Existing CCNPP surveillance test procedure STP-0-27-1/2, “Reactor Coolant System Leakage Evaluation,” for discovering wear on RCS valve discs and seating surfaces and for determining source of abnormal RCS leakage
- 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 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.)
- 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 and neutron 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 current licensing basis (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 PT) curves
- Fatigue analyses to predict cumulative effects on 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 letter dated 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 to discuss its responses to the RAIs during meetings on February 10 and 16, 1999 (NRC meeting summary dated March 19, 1999).

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, generic corrosion, IGA, pitting, SCC (including IGSCC and PWSCC), thermal damage, 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 evaluated the applicant's identification of ARDMs broken down into three major categories: (1) aging effects caused by material degradation (e.g., denting, erosion, erosion corrosion, galvanic corrosion, generic corrosion, IGA, pitting, SCC, thermal damage, 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, 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. Erosion corrosion of steam generator components occurs 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 l 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.

However, the staff noted that the applicant did not consider the steam generator carbon steel tube support structures as susceptible to erosion-corrosion. The applicant, in its response to Generic Letter 97-06, "Degradation of Steam Generator Internals," referenced a Combustion Engineering topical report that states erosion corrosion is a plausible ARDM under certain conditions. The staff requests that the applicant include erosion-corrosion of the tube support structures as a plausible ARDM to be managed for license renewal and the staff requests that the applicant submit an appropriate aging management program. In a letter dated November 19, 1998, the applicant stated that it performs periodic visual inspections of the secondary side of the steam generators (in particular the egg-crates and tube support plates) to look for signs of erosion and tube bundle fouling. However, the staff does not have enough information to conclude that this description of the applicant actions is enough to ensure the applicant will detect aging effects before there is a loss of intended function. Specifically, the applicant needs to clearly identify erosion corrosion of the egg-crate supports as a plausible ARDM, and also needs to provide the specific inspection scope, the inspection frequency, and the acceptance criteria for these visual inspections. The staff is also reviewing separately the applicant's response to GL 97-06 and will provide additional feedback relevant to this issue upon closeout of that GL. This is Open Item 3.2.3.1.1-1.

B. Pressurizer and Other RCS Components

For the pressurizer, the applicant determined that the ARDMs of general corrosion and various forms of SCC 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); manway bolting; and alloy 600 welds. On the basis of the description of the pressurizer internal and external environments and materials, the staff concludes 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. 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 corrode 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, fittings, and bolting). 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, bolting, studs, nuts, RPV head closure seal leakage detection piping, fittings, welds, valve bodies and bonnets, spray line nozzle safe end, and RCP and safety valve closure bolting. Thermal aging 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.

The staff finds the applicant's descriptions of plausible ARDMS affecting the pressurizer and RCS to be acceptable but finds 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 aging management programs, 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 considers SCC to be plausible for these pressurizer and RCS components, and should be managed by AMPs. The staff would consider the following existing programs to be 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 Bulletin 82-02, “Degradation of Threaded Fasteners in the RCS Pressure Boundary of PWR Plants”
- Primary water chemistry control program

The staff would rely on these programs 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 must propose an acceptable alternative. This is 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, 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 refers to embrittlement 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 tube 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 does 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 initial application to be generally acceptable, the staff also finds 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 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 non-potential. 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 reactor vessel internals components

Although the staff finds the applicant’s descriptions in the initial application of plausible ARDMS affecting the RVI to be generally acceptable, the staff also finds that the applicant did not discuss the basis for concluding why several RVI components 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 during the meeting on February 16, 1999, for NRC Question 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 4.3.16) The staff has reviewed the bases for non-plausible aging effects and agree that these aging effects do not require an aging management program for the above 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 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 aging management review in accordance with 10 CFR 54.21(a)(1)(ii).

(4) Irradiation-assisted stress corrosion cracking and neutron embrittlement

In Section 4.3.2 of Appendix A to the LRA, the applicant finds that IASCC is not plausible for CCNPP RVI. The staff requested that the applicant provide 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 Nos. 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 irradiation-assisted stress corrosion cracking (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 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 and neutron embrittlement. The aging management of CASS RVI components is discussed in section 3.2.3.3.1.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 above structural analysis results of GSI-15 and given that the RPV supports at CCNPP consist of the short column type under each of the four inlet nozzles, neutron embrittlement of RPV supports does not require an aging management program at CCNPP.

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 nuclear steam supply system (NSSS) and, consequently, fatigue design is part of the CLB for CCNPP. The staff reviewed the information regarding fatigue of NSSS components contained 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 on the applicant fatigue assessment of NSSS components. The applicant responded to these requests in two separate letters dated November 19, 1998, and a letter dated December 10, 1998.

In Section 4.1 of Appendix A to the LRA, the applicant addresses 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 transfer 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 addresses fatigue for the RPV and CEDMs, including the RVLMS. The applicant determined that fatigue is plausible for the RPV, 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 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 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 applicant should describe the scope of the CE review. This is a component of Open Item 3.2.3.1.2-1.

Section 4.3 of the application 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 need further evaluation. For further discussion of this issue, see Section 3.3.3.2.2 of this SER.

3.2.3.1.3 Aging Effects Caused by Wear and Stress Relaxation

In Section 4.1 of Appendix A of 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 due to 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 of the LRA, the applicant addresses wear for the RPV, RVLMS, and CEDMs. According to the applicant, components such as the RPV closure head studs, nuts, and washers: the ICI tube nozzle flanges, studs, and nuts, and some internal components are susceptible to mechanical wear due to relative motion between components.

In Section 4.3, “Reactor Vessel Internals System,” of Appendix A to the LRA, the applicant identifies wear and stress relaxation as ARDMs that require an AMR and AMPs for certain reactor vessel internals (RVI) device types to ensure plant safety during the period of extended plant operation. The device types for which 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 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 RVI 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 and/or neutron irradiation. 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 generic letters, information notices, and industry literature.

3.2.3.2 Aging Management Programs (AMPs) for License Renewal

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 application 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 covers all structures and components subject to an AM. 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 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 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 ½ 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. Except for the open items identified in this SER section, the staff concludes that the applicant submitted enough information in its license renewal application 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 ½ SGs" to detect and repair aging effects associated with denting, pitting and various forms of SCC of the steam generator tubes.

Program Scope

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 Technical Specifications (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.

Preventive/Mitigative Actions

There are no preventive or mitigative actions associated with this test procedure, and the staff did not identify a need for such.

Parameters Monitored

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). Following the EPRI guidelines directs 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, have been demonstrated to 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 it cannot be inspected) and any tube with a cracklike 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 issue report 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 enhance eddy current techniques, and improved analyst qualifications. The applicant demonstrated that it monitors tube degradation at CCNPP through repeated tube pulls.

The staff noted 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 identifies this issue as Open Item 3.2.3.2.1-1.

Except for the open items identified in this SER section, the staff concludes that test procedure STP-M-574-1/2 serves as an effective AMP 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 due to 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/Mitigative Actions

There are no preventive or mitigative actions associated with the ISI program, nor did the staff identify a need for such.

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 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 identify a need for any.

Acceptance Criteria

The applicant stated that any deviation from nominal wall thickness or any unusual variations in wall thickness would cause the applicant 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.

Except for the open items identified in this SER section, the staff concludes that the applicant submitted enough information in its license renewal application 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. Except for the open items in this SER section, 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) SG-20, “SG Primary Manway Cover Removal and Installation”

To manage erosion-corrosion of the secondary manway and handhole and associated cover plates as well as general corrosion and SCC of the steam generator primary manway studs, the applicant credited a modified version of technical procedure SG-20.

Program Scope

The staff finds the scope of the procedure acceptable because the procedure requires a specific examination of the manway and the manway bolting materials.

Preventive/Mitigative Actions

There are no preventive or mitigative actions associated with this test procedure, and the staff did not identify a need for such.

Parameters Inspected/Monitored

The applicant performs a visual inspection of the manway bolting materials to identify degradation. The staff considers visual inspections adequate to detect general corrosion because the effects of corrosion (e.g., rust, cracking, loss of material) is easily identifiable with visual inspections. In a letter dated November 18, 1998, the staff stated that visual inspection may not be adequate to detect SCC because of the size, nature, and location of such cracks. The staff asked the applicant to describe the basis for concluding that visual inspection of the studs is sufficient to detect SCC before there is a loss of intended function. In its response dated December 10, 1998, the applicant stated that it would modify SG-20 to include direction that if leakage has occurred at the joint, additional nondestructive examination (NDE) is required, and the NDE will include an examination for SCC of the studs. The NDE techniques will not rely on strictly visual techniques, but on other examination methods deemed appropriate, such as magnetic particle or dye penetrant examinations. The staff concludes visual inspections, supplemented by the surface techniques as needed are appropriate inspection parameters.

Detection of Aging Effects

Because of adequate scope, inspection technique (subject to the comments discussed above), and inspection frequency (every refueling outage), and operating experience to date, the staff finds that the procedure SG-20 provides reasonable assurance that the intended function of the manway and the manway bolting materials will be maintained.

Acceptance Criteria

The applicant stated that all relevant indications are evaluated, and the staff finds this comprehensive and thus acceptable.

Operating Experience

In a letter dated November 18, 1998, the staff asked the applicant to provide operating experience relevant to SG-20 and general corrosion and SCC of steam generator manway bolting materials. In its response dated December 10, 1998, the applicant described how the procedure had resulted in some new studs being installed in the steam generator primary manway because some studs were damaged in the removal/installation process. The staff concludes that the applicant's operating experience thus far with SG-20 appears to demonstrate effectiveness in identifying degraded conditions. Although the degradation was not the result of an ARDM, the experience does provide the applicant feedback that the scope, parameters, and corrective actions that are part of SG-20 worked effectively.

The staff concludes that the applicant submitted enough information in its LRA to show that SG-20 is an effective AMP for SCC of the steam generator manway and manway bolting materials.

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 staff's review of the BACI program is discussed in detail in Section 3.1.4 of this SER. Except for the open items identified in this SER section, 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 pressurizer components.

(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/Mitigative 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 boron deposits. All 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 Technical Specification limits on leakage to detect leakage that develops between refueling outages. The applicant stated that the inspection interval is sufficient to allow detection of cracked penetrations via boric acid leakage before the cracks attain critical size. The applicant stated that fracture mechanics calculations support the premise that axial cracks would be incapable of attaining a length that could cause unstable crack propagation before becoming throughwall cracks and being detected via boric acid leakage. The applicant also performed evaluations considering boric acid corrosion of carbon or alloy steel components due to leaking alloy 600 nozzles and concluded that such corrosion would not violate code requirements for wall thickness before the leakage would be detected by the routine visual inspection. The applicant also stated that industry experience, along with stress analyses, has shown that circumferential cracks are not expected in alloy 600 penetrations. This is consistent with staff conclusions as documented in a letter to the Nuclear Management Resource Council from the staff dated November 19, 1993, as well as in Generic Letter 97-01 “Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations.”

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.

Detection of Aging Effects

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 evaluation (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 "Parameters Inspected/Monitored" above.

Monitoring and Trending

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 ºF), 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. Except for the open items identified in this SER section, 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 applicant did not state the inspection method to be used. Visual methods, if used, would not be sufficient to monitor crack growth from SCC. Information is needed on how degradation would be detected before loss of function occurs. 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 maybe 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 is Open Item 3.2.3.2.1-2.

(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. For materials found to be susceptible, an AMP composed of periodic in-service inspection (ISI) and flaw acceptance criteria is used.

In Section 4.3.2 of Appendix A to the LRA, the applicant indicates that thermal aging 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 CF_3 and CF_8 and with a delta ferrite content above 20 percent; and
- statically cast parts with a molybdenum content exceeding the requirements of SA-351 Grades

CF_3 and CF_8 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 following revision to its proposed CASS screening criteria:

- Statically cast components with a molybdenum content exceeding the requirements of SA-351 Grades CF_3 and CF_8 and a delta ferrite content exceeding 10 percent will be subject to ISI in accordance with ASME Code Section XI.
- 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).
- Niobium containing cast stainless components are subject to ISI.
- The ISI procedures and techniques will be qualified to Appendix VIII to Section XI of the ASME Code, provided it is eventually possible to qualify an inspection technique for CASS.
- Flaws in CASS with ferrite levels exceeding 25 percent or niobium will be evaluated using ASME Code IWB-3640 procedures. If this occurs, fracture toughness data will be provided on a case-by-case basis.

The technical bases for the CASS program is contained in EPRI Technical Report 106092. 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 embrittlement, and do require inspection. The proposed screening criteria and inspection are acceptable when revised in accordance with the criteria documented during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999). The applicant should revise the CASS program as discussed in the February 16, 1999, meeting. This is Confirmatory Item 3.2.3.2.1-1.

(7) Other AMPs

The applicant considered certain aging effects to be non-plausible. However, in view of industry experience and data, the staff expected these ARDMs to be plausible and managed by AMPs. The staff would consider the following existing programs to be acceptable as AMPs or portions of AMPs because they have been shown to be effective in managing these effects:

- ASME Section XI
- Technical Specifications leakage requirements
- Programs based on the provisions of Bulletin 82-02, “Degradation of Threaded Fasteners in the RCS Pressure Boundary of PWR Plants”
- Primary water chemistry control programs

The applicant should commit to these programs and submit a brief description of operating experience with these programs. Otherwise, the applicant must propose an acceptable alternative. This is a component of Open Item 3.2.3.1.1-2.

For cracking of the pressurizer shell and heads, including cladding cracking, the applicant stated that cracking was not plausible and did not need aging management. Industry experience has shown that cracking is a plausible ARDM that requires aging management, typically by inspections. The applicant should propose an AMP. This is Open Item 3.2.3.2.1-3.

For the cracking of small-bore piping (i.e., smaller that 4 inches nominal pipe size but greater than 1 inch), the applicant is using the same methods for managing aging as for large-bore piping, except for thermal embrittlement which the applicant does not consider a plausible mechanism. For the staff's evaluation of these AMPs, see the preceding section on AMPs of large-bore piping. In addition, the applicant should perform an augmented inspection of small-bore piping for 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 is Open Item 3.2.3.2.1-4.

C. Reactor Pressure Vessel and Internals

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. Except for the open items identified in this SER section, 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 year 55, 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 year 55, the applicant must install neutron dosimetry to permit tracking of the fluence to the RPV.

The proposed program, as the applicant agreed to modify during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), will provide neutron irradiated surveillance data applicable to the period of extended operation. Therefore, it will be able to monitor neutron irradiation during the period of extended operation as is acceptable. The applicant should revise the CRVSP as discussed during the February 16, 1999, meeting. This is 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 RV internals 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 will 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 inspection 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 barrel inside surfaces (the core barrel surface that faces the core). These corners are constructed by welding annealed 304 stainless steel plate. The residual stresses due to 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 barrel. 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 towards 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 barrel 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 barrel, 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 and neutron embrittlement of CASS RVI components, the applicant agreed to modify its approach for management of these ARDMs. This modified approach consists of either an enhanced VT-1 examination of the affected components as part of the applicant's 10-year ISI program during the license renewal term (as discussed above), or a component-specific evaluation to determine the susceptibility to loss of fracture toughness. The proposed evaluation will look first at the neutron fluence of the component. If the neutron fluence is greater than 1 x 10^{17} n/cm^2 (E > 1 MeV), the applicant will conduct a mechanical loading assessment on the component. This assessment will determine the maximum tensile loading on the component during ASME Code Level A, B, C and D conditions. If the loading is compressive or low enough to preclude fracture of the component, then the component would not require inspection. Failure to meet this criterion would require continued use of the enhanced VT-1 inspection. If the neutron fluence is less than 1 x 10^{17} n/cm^2 (E > 1 MeV), the applicant will evaluate whether the affected component(s) are bounded by the screening criteria developed in the CASS evaluation program, discussed earlier in this SER. In order to demonstrate that the CASS evaluation program screening criteria are applicable to RVI components, the applicant will perform a flow tolerance evaluation specific to the reactor vessel internals. If the screening criteria are not satisfied, then an enhanced VT-1 inspection will be performed for the component.

The staff finds the program to be acceptable because the enhanced VT-1 inspection will detect cracks that could lead to failure of the CASS 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. 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. The staff requests that the applicant confirm that CEDMs are included in the periodic inspections via the BACI program, confirm that cracking of CEDMs has been considered for a 60-year life, and provide the results of the susceptibility evaluation for the CEDMs relative to this time frame, and provide operating experience from inspections of CEDM nozzles at CCNPP, if available. This is 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 discussion above 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 is above or below the “critical stress” for SCC. As discussed during a meeting on February 16, 1999 (NRC meeting summary dated March 19, 1999), for NRC Question No. 4.3.15, the applicant indicated that after further review, the function of the CEA shroud bolts is not safety related and, therefore, this stress analysis program would not be implemented. Pending review of an applicant submital documenting this finding, this is Confirmatory Item 3.2.3.2.1-4.

(9) ARDI Program

An ARDI program is planned to manage the effects of SCC of the CEA shroud bolts. However, as discussed in 3.2.3.2.1C(8) of this SER, the applicant indicated that the CEA shroud bolts do not perform a safety function in accordance with the requirements of 10 CFR 54.4. The applicant was asked to document the resolution of the issue with a description of the function of the CEA shroud bolts that included an explanation of why they do not meet the criteria contained in 10 CFR 54.4. This is part of Confirmatory Item 3.2.3.2.1-4.

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 the 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 3.2.3.1.3 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 the 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, 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. This is a component of Open Item 3.2.3.1.2-1.

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.

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 applicant should 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. This is a component of Open Item 3.2.3.1.2-1.

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 reported 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. However, the open issues identified regarding the FMP must be resolved in order for the staff to accept this sampling approach for managing 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 applicant should complete its analyses of the RVI 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. This is a component of Open Item 3.2.3.1.2-1.

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. 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. Except for the open items identified in this SER section, 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 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.
- CCNPP technical procedure RCS-10 provides for visual inspection of the pressurizer manway studs, nuts, and seating surfaces.
- CCNPP technical procedures SG-1, SG-2, SG-5, and SG-6 provide for the inspection of the SG closure surfaces.
- CCNPP technical procedure SG-20 provides for inspection of the SG primary manway flange seating surfaces.
- 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 provides for inspections of SG tubes.

Based on the frequency of the inspections and the inspection technique used the staff concludes 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 maintained during the extended period of operation.

3.2.3.2.4 Wear and Stress Relaxation of Reactor Vessel Internals

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 indicates 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 provide all the information requested. The response was did not include a description of the accuracy of visual examinations required to provide reliable measurements to mange aging effects of wear on the HDR.

The staff held a meeting with the applicant on February 18, 1999 (NRC meeting summary dated March 19, 1999), to address this issue. The issue was discussed with the applicant's licensing representatives and cognizant CCNPP individuals involved in the ISI program and the activities associated with the 10-year ISI RVI examinations and inspections performed during their removal and reinstallation from the pressure vessel (PV). The following information was provided by the applicant during these discussions:

- The ISI visual examinations only identify indications of such surface wear as scratches and gouges and do not provide information on the depth of wear.
- During the inspection of the RVI and its PV support ledge, the depth of wear on mating surfaces is not measured.
- The staff inquired about measurements taken after the reinstallation of the RVI and before lowering the PV head to ensure the proper seating of the RVI. Measurements of the elevation of the top surface of the HDR or RVI flange relative the top of the PV closure flange would ensure proper seating of the RVI and also provide the information for assurance that the effects of wear on the HDR function are adequately managed.
- On the basis of a check of the ISI RVI removal and reinstallation procedures, the applicant could not determine if the RVI seating and PV closure elevation were measured. However, the applicant noted that the 10-year ISI examinations and inspections of the RVI and PV are performed by a subcontractor, and their procedures may include the elevation measurements in their RVI reinstallation procedures. The applicant intends to discuss this with the subcontractor and review the procedures to resolve and document the issue.

Pending an applicant submittal of a documented satisfactory resolution of this issue, this is Open Item 3.2.3.2.4-1.

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 provide 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 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). The following information was given by the applicant as the basis for not considering stress relaxation plausible for the HDR:

- The radiation levels in the area of the HDR are not sufficient for a stress relaxation ARDM to occur. In-pile testing of stainless steel material has shown that substantial loss of preload is possible at PWR operating temperatures in a high-radiation field of approximately 5 x 10^{20} n/cm^2 (E>1MEV) when materials are stressed at or above yield stress. The applicant determined that in extrapolating fluence values from a CE memorandum, dated August 4, 1977, "Relaxation of 13Cr-4Ni Hold Down Ring Material," that fluence levels of the HDR will be in the range of 10^{12} to 10^{13} n/cm^2 for a 60-year life.
- On the basis of discussions with CE, the applicant is certain that the operating stress levels in the HDR are much less than two-thirds of the material yield strength. The HDR is made from ASTM_A182-72, GR. F6, AISI

Pending an applicant submittal documenting this information, this is Confirmatory Item 3.2.3.2.4-1.

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. The staff met with the applicant on February 17, 1999 (NRC meeting summary dated March 19, 1999), to address this issue. The applicant provided the following information during these discussions:

- Contrary to the information provided in Section 4.3,2 of Appendix A to the LRA , the applicant will not be performing an analysis to determine if the existing stresses are above or below the threshold level for SCC. This change evolved from BG&E's determination that the CEA shroud bolts are not within the scope of license renewal.

- The CEA shroud bolts do not perform a safety function in accordance with the requirements of 10 CFR 54.4.

The applicant was asked to document the resolution of the issue with a description of the function of the CEA shroud bolts that included an explanation of why they do not meet the criteria contained in 10 CFR 54.4. This issue, which is addressed in 3.2.3.2.1.C(8) of this SER, is Confirmatory Item 3.2.3.2.1-4.

The RVI technical report indicates that at reactor operating temperatures, neutron embrittlement is plausible for device types that would experience high-energy neutron flux. Although the components nearest the core experience such high fluxes, the fluence levels are not sufficient to cause appreciable neutron embrittlement of components located above the reactor vessel nozzles. The CEA shroud bolts are located directly over the core and well below the pressure vessel nozzles. The report indicates, in part, that the effect of neutron embrittlement is a loss of fracture toughness that leads to cracking or fracture of bolts or fasteners, and that these effects are precursors to the loss of the intended function for the component. The ISI program visual examination is proposed as adequate for control of this ARDM. On the basis of the drawings presented in Appendix A to the LRA, the CEA shroud bolts are almost completely buried within the CEA shroud flange and fuel alignment plate assembly and are not readily accessible for visual examination except for the tops of the bolt heads. Bolt cracking or fracture occurs at the juncture of the bolt head and shank, which is not accessible for visual inspection. On September 3, 1998, the staff requested a description of the portions of the CEA shroud bolts that are accessible for visual examination and a discussion of how the observations can be used to reliably demonstrate and provide adequate assurance that neutron embrittlement will be managed during the period of extended operation (NRC Question No. 4.3.23). On November 19, 1998, the applicant responded to the question. The response did not address the request for a description of the portions of the bolts that are accessible for visual examination and how the observations can be used to reliably demonstrate, and provide adequate assurance, that neutron embrittlement will be managed during the period of extended operation. This issue was discussed in the staff meeting with the applicant on February 18, 1999 (NRC meeting summary dated March 19, 1999). During the meeting, the applicant acknowledged that the shank of the bolts is not accessible for visual examination. However, the applicant reported that the CEA shroud bolts are not within the scope of license renewal in accordance with 10 CFR 54.4 as discussed during a meeting on February 17, 1999 (NRC meeting summary dated March 19, 1999), with regard to the resolution of NRC Question No. 4.3.15. Pending an applicant submittal of a satisfactory resolution of the issue, this is Confirmatory Item 3.2.3.2.1-4, which is also discussed in Section 3.2.3.2.1C(8) of this SER.

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 Section 4.0 of this staff 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 PT) 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 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 in 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 54.21(c)(i) because the PTS screening criteria is satisfied for 20 years beyond the current expiration date of the license.

B. Heatup/Cooldown (Pressure/Temperature or PT) 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 states 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 PT 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 54.21(c)(i) for Unit 1 because the PT limits are valid for 60 years. For Unit 2 the licensee satisfies 54.21(c)(iii) because the PT limits are adequate for 30 EFPY and will be updated to meet the requirements of Appendix G, 10 CFR Part 50 for 48 EFPY (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 of Section XI of the ASME Code. Therefore, with respect to the charpy upper-shelf energy the licensee satisfies 54.21(c)(i) because upper-shelf energy will not fall below 50 ft-lbs before 48 EFPY.

(2) Fatigue

In Section 2.1.3.3 of Appendix A to the LRA, the applicant states 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 design life. Consequently, fatigue 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. Consequently, the staff concludes that the FMP TLAA for the RPV and RCS is only adequate for the current design life of 40 years.

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 provide 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 the only place it relied on the EPRI report was 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 is also applicable to these systems.

If GSI-190 is not resolved generically prior to CCNPP operation in the extended period, the applicant must adequately resolve environmental effects on high usage factors with bounding analyses or a monitoring program on a plant-specific basis. This is Confirmatory Item 3.2.3.3-1.

3.2.4 Conclusions

The staff has reviewed the information included in Section 4.1, "Reactor Coolant System," Section 4.2, "Reactor Pressure Vessels and Control Element Drive Mechanisms/Electrical System," and Section 4.3 "Reactor Vessel Internals System," of Appendix A, "Technical Information," to the LRA and additional information provided by the applicant in response to the staff RAIs. Except for the open items identified in this SER section, 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 Feature Systems

3.3.1 Introduction

BGE (the applicant) described its aging management review (AMR) of the engineered safety features (ESFs) in the following three sections of Appendix A to its license renewal application (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 Application

3.3.2.1 Structures and Components Subject to Aging Management Review

Section 5.5.1.1 of Appendix A to the LRA describes the CI group as consisting only of those CI systems that either have no other components within the scope of license renewal or have components that are evaluated 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 require an AMR are identified in Table 5.5-1 of 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 the LRA identifies the components in the CS system that are subject to an AMR. They include 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 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 above 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, SSC, and weathering as plausible ARDMs for the SI system.

3.3.2.3 Aging Management Programs

The applicant identified the following aging management programs (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 CO-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 operation, consistent with the current licensing basis (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 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, 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, 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 carbon and 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 above-mentioned materials are known to experience these aging mechanisms when exposed to well water and treated water. Based on 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) 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 as to why fatigue is not considered as a plausible aging mechanism for CI group components. In a letter dated November 12, 1998, the applicant responded that the design for 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 above-mentioned materials are known to experience these aging mechanisms when exposed to treated water. Based on 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 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 responded that the reference to "thin-walled" would be deleted. 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 SSC.

Group 6 consists of the 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 for License Renewal

The staff 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 AMR. The staff's evaluation of the applicant's corrective action program is provided 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. On the basis of this evaluation, the staff concludes that the licensee provided enough information in Appendix A to the LRA to show that the BACI Program is an effective AMP to manage general corrosion of the external surfaces of the applicable alloy and carbon steel components in the CI group and the CS and SI systems.

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 four of its chemistry programs, namely, CP-204, "Specification and Surveillance Primary Systems"; CP-206," Specification and Surveillance Component Cooling/Service Water System"; CP-202, "Specification and Surveillances Demineralized Water, Safety-Related Battery Water, and Well Water Systems"; and CP-224 "Monitoring Radioactivity in Systems Normally Uncontaminated," 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. On the basis of the staff's evaluation in Section 3.1.2, the staff concludes that the licensee provided enough information in Appendix A to the LRA to show that CP-204, CP-206, CP-202, and CP-224 are effective AMPs to manage general corrosion, crevice corrosion, and pitting of the internal surfaces of the applicable components in the CS and SI systems.

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 licensee cited 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 licensee welded an additional reinforcement plate or penetration seal plate 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 ºF. 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 a RWT. The licensee attributed the leak to SCC at the penetration weld and performed weld repair to correct the deficiency. The licensee 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 licensee stated that visual inspections for leakage through the "telltale" holes would detect the effects of SCC and allow for timely repair. The licensee 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 licensee provided enough information in its LRA to show that the walkdown inspections will detect SCC of the RWT penetration welds. The licensee plans to modify the program to (a) specifically identify the field-erected tanks within the scope of the performance assessments, (b) provide additional visual inspection criteria specific to detecting leakage near the RWT penetrations, and (c) add guidance regarding approval authority for significant departures from the specified walkdown inspection scope and schedule. To capture this modification, this is Confirmatory item 3.3.3.2.1-1. Because the susceptible locations are not directly accessible, the licensee will complete an engineering review of SCC at the RWT penetrations that will either (a) 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 (b) include RWT penetrations in the ARDI program (previously described). This engineering evaluation is Confirmatory Item 3.3.3.2.1-2 to capture this element of the licensee’s AMP for SCC.

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 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 (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 B31.7 Class II requirements and was subsequently upgraded to Class I requirements. The fatigue criteria applicable to Class I is 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 SE. The applicant described the controlling plant transients and the parameters monitored by the FMP for these locations in response to NRC Questions 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 on a periodic basis. These data are evaluated, and updated usage factors are calculated on a semiannual basis. 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 regarding thermal stratification to determine whether SI piping changes are necessary and to determine the impact of such changes on fatigue usage parameters used by the FMP. In NRC Question No. 7.21, the staff asked that the applicant 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 re-analysis 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. The applicant concluded that the management of nuclear steam supply system (NSSS) fatigue effects meets the requirements of 10 CFR 54.21(c)(1)(iii). The staff notes that 10 CFR 54.21(c)(1)(iii) states that the applicant shall demonstrate "that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation." According to the applicant, the new analysis and potential modifications to the FMP will be complete by the end of 2003. However, the staff understands that whether additional monitoring locations are added to the FMP is not based on a specific value of the usage factor, but may also be based on subjective judgement. Consequently, the applicant has not demonstrated that the effects of aging on intended SI functions will be adequately managed for the extended period of operation. The applicant should complete the thermal stratification analysis of the SI piping and modify the FMP as necessary. This is Confirmatory Item 3.3.3.2.2-1.

As discussed in Section 3.2 of this SER, the applicant's FMP relies on sampling 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. Resolution of the open issue previously discussed is necessary in order for the staff to conclude that the applicant's FMP sampling approach provides an adequate method to manage thermal fatigue of the SI components. In addition, resolution of the open issues regarding the FMP identified in Section 3.2 of this SER is also necessary.

3.3.3.2.3 Weathering

To manage weathering of the RWT perimeter seal (Group 6 in the SI system), the licensee 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. Upon satisfactory closure of the confirmatory items discussed in Section 3.1.3, the staff concludes that the licensee submitted enough information in its LRA to show that the walkdown inspections will detect weathering of the RWT perimeter seals. The licensee plans to modify the program to include additional visual inspection criteria specific to the perimeter seal. To capture this modification, this item is Confirmatory Item 3.3.3.2.3-1.

3.3.3.3 Time-limited Aging Analyses

Section 2.1.3.3 of the LRA identifies 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 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 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 of the TLAA is contained in Section 3.2.3.3 of the SER. The open issue discussed in Section 3.2.3.3 is also applicable to the SI piping. Consequently, the staff concludes that the TLAA for the SI piping is only adequate for the current design life of 40 years.

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 RAIs. Upon implementation of the confirmatory items identified in this SER section, 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

BGE (the applicant) described its aging management review (AMR) of the auxiliary systems (ASs) for license renewal in three separate sections of its LRA. These three sections are 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 Application

3.4.2.1 Structures and Components Subject to an Aging Management Review

Section 5.2 of Appendix A to the LRA describes the CVCS, which provides control of reactor coolant chemistry through boric acid injection for minimizing corrosion and maintaining 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, 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 AMR is listed in Table 5.2-2 of Appendix A to the LRA.

Section 5.4 of Appendix A to the LRA describes 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. The CAS is seismic Category I, and its components are primarily constructed of carbon steel and subjected to an internal environment of compressed air. The applicant's selection of device types requiring AMR is listed in Table 5.4-1 of Appendix A to the LRA.

Section 5.10 of Appendix A to the LRA describes the systems for FP. The FP system includes equipment and facilities important to safety that provide functions of detecting, fighting, and extinguishing fires. Thus, the FP system is needed to protect safety-related (SR) equipment and structures from fire or explosion. Chapter 5.10 of the LRA addresses sixteen systems credited with FP functions within its scope. The applicant performed AMRs on nine of these 16 systems. These nine systems are: SRW, CC, Compressed Air, Diesel fuel oil, AFW, Chemical and Volume Control, RCS, N2H2, MS. These nine 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 Chapter 5.10. The non-safety-related PB parts of these systems are the subject of the staff's review.

The remaining seven 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 AMR for these systems; that is, it does not describe them under separate chapters of the LRA. These systems are addressed in Chapter 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 SE are the fire barrier materials found in five systems. These are Intake Structure, Primary Containment, Barriers and Barrier Penetrations, Auxiliary Building, Turbine Building. The results of the AMR for these systems are provided in Sections 3.3A, 3.3B, 3.3C, and 3.3E of the LRA. These five systems are not addressed in Chapter 5.10.

3.4.2.2 Effects of Aging

The applicant evaluated the applicability of age-related degradation mechanisms (ARDMs) for the A.S. components subject to 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, erosion/corrosion, wear, thermal fatigue, and vibration 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 pump operation. 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, particulate content, and traces of oil or hydrocarbons.

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 section below describes 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 flow 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 with a coating that is not degraded by high temperatures.

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 the 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 leakage in plant heating piping from corrosion. 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.

The next section describes the 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, and hardware, access doors, jambs, and hardware, caulking and sealants, and watertight doors.

For the intake structure, the components that, according to the applicant, contribute as fire barriers are columns, walls, cast-in-place anchors/embedments, fire doors, jambs, and 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, roof slabs, masonry block walls, fire doors, jambs, and hardware, expansion joints, watertight doors, and gypsum board.

The applicant identified weathering of caulking and sealants located outdoors as a plausible ARDM. 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 located outdoors as a plausible ARDM. The applicant shop 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 Preventive Maintenance 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 the following FP-related systems: well and pretreated water, SRW, CC, CA, plant heating, auxiliary feedwater, demineralized water, 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, vibrational fatigue, and wear on CVCS components, (2) general corrosion at the containment penetration of the PA subsystem carbon steel components in the CAS, and (3) corrosion, general corrosion, and pitting on the FP-related piping in 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 current licensing basis (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 4 different methods to manage aging of SSCs used for FP. The applicant systematically evaluated these methods in the sequence below to apply them to the subject components. The methods are:

- Process fire protection program activities
- Process performance and condition monitoring activities
- Process aging management programs credited for safety-related pressure boundary (safety-related PB) components that apply to the non-safety-related pressure boundary (non-safety-related PB) components
- Process normal IPA AMR process

The first method the applicant applies is *process 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 Specifications contain applicability, compensatory actions, testing requirements, and testing 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 three systems: fire protection, diesel fuel oil, and nitrogen and hydrogen gas. The applicant credited this program for partially managing aging effects for the following two systems: 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 *process performance and condition monitoring activities*.

Process 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.

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 structures, systems, and components 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 structures, systems, and components 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 *process aging management programs 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.

<u>Process aging management programs credited for safety-related PB components that apply to the non-safety-related PB components</u>

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 aging management programs credited for the safety-related pressure boundary components if the programs are equally applicable to the non-safety related pressure boundary components. The applicant credited the safety-related pressure boundary aging management review for fully managing aging effects for 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.

<u>Process normal IPA AMR process</u>.

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 specifications 3.7.12 and 4.7.12.a; 10 CFR Part 50, Appendix R; and NRC Generic Letter 86-10, "Implementation of Fire Protection Requirements." Plant personnel typically perform these inspections every 18 months in accordance with technical specification 4.7.12.a.

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 any 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, "Time-Limited Aging Analyses (TLAAs)," of Appendix A to the LRA states that TLAAs are not specifically applicable to the auxiliary systems. However, Section 2.1.3.3 of Appendix A to the LRA indicates that the fatigue analysis of NSSS components is included in the TLAAs. Since portions of the CVCS are connected to the RCS, it is implied that fatigue is 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 3, 1998), and by letter dated November 2, 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 to 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/or 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. Based on the above discussion, 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 are not subject to 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 sea water indicates that the atmosphere at the plant can be classified as marine. Corrosion in a marine atmosphere can occur 400 to 500 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 for License Renewal

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about the aging management programs 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 due to 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 license renewal application. 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 aging management programs 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 aging management review. The staff's evaluation of the applicant's corrective action program is discussed in Section 3.1.5 of this SER. Upon satisfactory closure of the confirmatory items discussed in Section 3.1.5, the staff concludes that the applicant has 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 aging management programs: 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. The staff concludes that the applicant has demonstrated that CP-204 and CP-206 are effective aging management programs to manage crevice corrosion and pitting of the internal surfaces of the stainless steel CVCS components.

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. Upon satisfactory closure of the confirmatory open items discussed in Section 3.1.4, the staff concludes that the applicant has demonstrated that the BACI program is an effective aging management program to manage general corrosion of the external surfaces of the alloy and carbon steel CVCS components.

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. Upon satisfactory closure of the open items discussed in Section 3.1.6, the staff concludes that the applicant has shown that the ARDI program is an effective aging management program to detect 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.

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 due to exposure to moisture carryover from IA, the applicant cited Preventive Maintenance Checklists IPM 10000 (10001), "Check Unit 1(2) Instrument Air Quality." The scope of the preventive maintenance encompasses the entire instrument air system and thus also encompasses the affected CVCS components. The mitigative action associated with this preventive maintenance 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 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 preventive maintenance 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 Preventive Maintenance 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, therefore, are not subject to AMR.

To manage SCC of the external surfaces of certain stainless steel CVCS components exposed to halogens at elevated temperatures, the applicant cited a plant modification. The external surfaces of these stainless steel CVCS components are in contact with halogens that are found in the adhesives used to adhere the heat tracing to the component exterior surfaces and are subject to relatively high temperatures. The applicant installed electrical heat tracing to maintain the boric acid above the saturation temperature; the heat tracing maintains a temperature of approximately 160 ºF. The applicant plans to replace the original adhesive with another method to adhere the heat tracing without introducing halogens. The applicant initiated a plant modification in 1991 to replace the original heat tracing in the CVCS. Portions of the original heat tracing have already been replaced. The modification will be completely implemented before the start of the license renewal period. Implementation of this modification will render this ARDM no longer plausible. The staff finds the scope of the plant modification to be effective in that it encompasses the entire CVCS. 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 to be managed. There are no parameters monitored or inspected as part of this plant modification. However, the staff believes there should be 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. This is Open Item 3.4.3.2.1-1. 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 end 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 is Open Item 3.4.3.2.1-2. Upon satisfactory closure of the open items discussed above, the staff concludes that the plant modification will render SCC of the CVCS components implausible and thus there will no longer be a need to demonstrate an aging management program.

For the CAS, the applicant cited the following aging management programs: Surveillance Test Procedures (STP) STP-M-583-2 "pump and valve inservice testing (IST)," and STP-M-571F-1/2 "local leak rate test, Penetrations 19A, 19B, and 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 due to 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/mitigative 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 that 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 that 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 Section 3.1.3 of this SER.

The staff finds that aging of the passive non-safety-related structures and components is adequately managed because they are subject to the same aging management activities as similar safety-related components.

For the turbine building, intake structure, 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 subsection 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. Upon satisfactory closure of any confirmatory items in that review, 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 significant corrosion of the steel occurs.   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 a meeting on February 18, 1999 (NRC meeting summary dated March 19, 1999), 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 a Combustion Engineering report. 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. The applicant should supplement its response to the Question to include the review of the TE and HXs discussed above. This is Open Item 3.4.3.2.2-1.

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 a reanalysis of the CVCS and auxiliary spray piping was performed 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 through 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 sampling 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 open issues discussed in Section 3.2 of this SER must be resolved in order for the staff to conclude that the FMP sampling approach provides an adequate method to manage thermal fatigue of the 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 an SE 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. In a meeting on February 10, 1999 (NRC meeting summary dated March 19, 1999), held at CCNPP, the applicant stated that it plans to revise the LRA position 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. This is Confirmatory item 3.4.2.2-1.

3.4.3.3 Time-Limited Aging Analyses

Section 2.1.3.3 of Appendix A to the LRA notes 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 concluded that the FMP TLAA for the CVCS is only adequate for the current design life of 40 years. The staff's evaluation of the TLAA is contained in Section 3.2.3.3 of this SER. The open issue discussed in Section 3.2.3.3 is also applicable to the CVCS.

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 there are open items discussed in this Section of this SER. If the applicant resolves these open items, the staff will be able to conclude 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 that 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

BGE (the applicant) described its aging management review (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 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 Provided 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 enchanters, 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, and brass. The internal environment is water at a design pressure of 150 psig and a maximum design temperature of 180 ^{0}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 describes 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 intake structure 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, SWS, 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 emergency core cooling system pump room cooler in order to transfer heat from these heat enchanters 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 or cast iron piping lined with cement mortar, Saran or Kynar, red brass piping, and 70-30 copper-nickel piping, The internal environment is saltwater.

Section 5.17 of Appendix A to the application 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 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 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 AMR. The applicant determined that the aging effects due to the following "plausible" ARDMs should be managed for license renewal: crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion (MIC), 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 Program

The applicant identified the following aging management programs 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 Preventive Maintenance Checklists MPM01012, MPM01013, and MPM01143 (existing program)
- CCNPP Administrative Procedure MN-1-102, "Preventive Maintenance Program" (existing program)
- Repetitive Tasks 10122063 through 10120268, 10122096 through 10122102, 20122067 through 20122072, and 20122100 through 20122106
- Checklists MPM04004, MPM04194, MPM12200, MPM12201, and MPM01001 (modification needed)
- Procedure PUMP-03 (modified program)
- Checklists IPM10000 and IPM10001 (existing program)
- Repetitive Tasks 10112052, 10112053, 10152023, 10152024, 20112006, 20112027, 20152020, and 20152021
- Checklists MPM05000 and MPM00006 (existing program)
- Checklists MPM05000 and MPM05101 (modified program)

- Repetitive Tasks 10122095 (modification needed) 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)
- Containment Penetration Leak Rate Testing (STP-M-571E-1/2) (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)

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 current licensing basis (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 included 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 and Aging Management Programs

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, and brass. 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. The applicant identified the applicable ARDMs as crevice corrosion, galvanic corrosion, general corrosion, microbiologically induced corrosion (MIC), pitting, erosion/corrosion, 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 provided 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 aboveground 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 leaking salt water. 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 gallon per minute. 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 be 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 put these ARDMs in six groups: (1) crevice corrosion and pitting, (2) erosion/corrosion, (3) general corrosion, (4) rubber degradation, (5) selective leaching, and (6) wear. For each of these groups of ARDMs, the applicant described and evaluated the effects of each of these ARDM groups on the component materials, outlined the methods to manage aging, identified aging management programs, 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 which 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 ºF - 110 ºF and 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.

Based on industry data and experience, the staff concludes there are not 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 6 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 180 ^{0}F.

To protect the CC system components from corrosion damage, the applicant is monitoring its chemistry parameters using Calvert Cliffs 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.

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 degradation of these components is not occurring. The staff's evaluation of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

Based on 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 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 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 which 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 ºF—110 ºF 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 due to 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 due to 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. Inspections will be performed, and appropriate corrective action will be taken if erosion/corrosion is discovered. Corrective actions 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.

Based on 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 material. 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 tank.

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.

Based on 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 liner 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.

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 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.” This appendix specifies containment leakage testing requirements, including the types of tests required, testing frequency, test methods, acceptance criteria, and reporting requirements. The applicant believes that Appendix J should provide sufficient information for estimating the degree of damage to a valve’s liner due to aging.

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 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-brass. 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 periodic 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.

Based on 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, control, and relief 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 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. Inspection of the check valves in the CC system will be included in the applicant's ARDI 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 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 6 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 aging management programs, and demonstrated the adequacy of the proposed aging management for each of the identified ARDMs.

Based on industry data and experience, the staff concludes that there are no other applicable ARDMs for the saltwater system. The following is the staff evaluation of the AMPs for these ARDMs.

3.5.3.1.2.1 Crevice Corrosion, General Corrosion, MIC, and Pitting in the Components Without 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, stainless steel, and Monel.

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 which 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 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 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 and elastomer degradation, against which linings do not protect. 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 which are not eliminated by the presence of linings, the applicant subjects the components in the SWS to periodic inspections through the existing preventive maintenance 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.

Based on the existing periodic inspections supplemented by ARDI, the staff concludes that these program 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 preventive maintenance program mitigates the effects of corrosion by minimizing moisture inside the components.

The applicant has inspected the piping immediately downstream of the salt water 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. Based on the mitigative effects of the preventive maintenance 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 tube sheets, 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 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 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 preventive maintenance program is credited for ensuring that degradation of the heat exchangers will be controlled. Specifically preventive maintenance 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 10112052, 10112053, 10152023, 10152024, 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 following guidance provided by CP-206 procedure for maintaining shell side water chemistry and periodic inspections and cleaning of the heat exchanger tubes under the preventive maintenance program will provide adequate protection for these heat exchangers against the aging effects of this ARDM 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 protective coating fails.

The applicant conducts periodic visual inspections and testing for the tube side of the coolers through the existing CCNPP preventive maintenance program to determine if any degradation is occurring. Specifically, preventive maintenance specified in Checklists MPM 05000 and MPM 05101 for the ECCS pump room air coolers are performed every 24 weeks. These checklists require 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 discovered deficiencies. 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 preventive maintenance on the ECCS Pump Room coolers will provide adequate protection of these air coolers against the aging effects of these ARDMs and 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 discover 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 preventive maintenance program. These inspections are accomplished through Repetitive Tasks 10122095 and 20122099, which are performed every 6 years. The applicant credited its ARDI program for the orifice which is not inspected by the current program because of its infrequent use. The staff’s review of the ARDI program is discussed in detail in Section 3.1.6 of this SER.

The staff concludes that these programs will provide adequate protection for these flow orifices against the aging effects of this ARDM and will provide reasonable assurance that these flow orifices 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 system (designated as SRW): 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 aging management programs, and demonstrated the adequacy of the proposed aging management for each of the identified ARDMs.

Section 5.17 indicates that the SRW system was designed to the American National Standards Institute (ANSI) Standard, B31.1 Code requirements. Although ANSI 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. Based on the applicant's assessment the staff agrees that thermal fatigue is not a plausible ARDM for the SRW piping system.

Based on 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 degradation of the components is not occurring. 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.

Based on 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 against aging effects of crevice corrosion/pitting and provide reasonable assurance that these components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.3.1.3.2 Erosion/Corrosion

Erosion/corrosion occurs in the systems containing components made of carbon steel and exposed to moving, turbulent water. In the SRW the piping is carbon steel fabricated into straight sections, bends and tees, a geometry to 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 pH above 9.0. This water remains subcooled to a temperature of 130 ºF and a pressure 102 psig. Based on 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. 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 and determine whether it 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 applicant also indicates that the results of the ARDI program for the safety-related portion of piping will be evaluated for applicability to the non-safety-related SRW piping. 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 provided a response, dated November 16, 1998, to the staff’s RAI and supplemented the 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.

Based on existing periodic inspections supplemented by ARDI, the staff concludes that there is adequate protection for the components in the SRW 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 Preventive Maintenance Checklists IPM 10000 and IPM 10001 is used to inspect the valves. These checklists 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. As a safety precaution, the applicant credited its ARDI program to provide additional assurance that the effects of plausible ARDMs 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 safety evaluation.

Based on the mitigative effects of the water chemistry and preventive maintenance 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 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.

Based on 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 above wear mechanisms, impeded relative motion between two surfaces held in intimate 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 four to five 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 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) crevice corrosion, galvanic corrosion, general corrosion, and pitting 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 aging management programs and demonstrated their adequacy.

Section 5.18.1 of Section 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 determined that the cracking was due to high-cycle fatigue caused by cavitation-induced vibration. The sources of vibration were determined to be 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 implementation of these improvements has prevented recurrence of cracking in SFPCS piping, this cracking is not considered to be a plausible ARDM. Based on 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 susceptible to cracking, as well as the modified valves and orifices is subject to AMR. In its response, the applicant stated that these piping components are in the scope of license renewal and are subject to 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 ºF. 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.

Based on 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 Crevice Corrosion, Galvanic Corrosion, General Corrosion, and Pitting

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 above listed components 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 the Common Aging Management, 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 due to 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.

Based on the mitigative effects of the water chemistry program and the additional assurance provided by the BACI 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 and Radiation Damage

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. Rubber in diaphragms after prolonged exposure to radiation environment will lose its mechanical strength and eventually will break, causing hand valves to leak.

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 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 intimate contact for 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 concludes that these inspections and tests will provide a basis for an aging management program which will ensure that no degradation of valve design function will occur and that the valves will remain operative during the extended period of operation.

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 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 preventive maintenance program. This program follows directives given in CCNPP Preventive Maintenance Tasks 00672007 and 00672008, which implement Mechanical Preventive Maintenance 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 make it specifically applicable to 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 preventive maintenance 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 provide 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 License Renewal

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 evaluation of the applicant’s identification of TLAAs is provided separately in Section 4.0 of this SER.

3.5.4 Conclusions

The staff has reviewed the information included 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 provided by the applicant in response to the staff 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 set forth 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 that 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

BGE described its aging management review (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 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.

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. Due to the unique circumstances pertaining to these HVAC systems (i.e., they have been 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 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 additional AMR. However, to justify such a conclusion, the applicant should 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 is Confirmatory Item 3.6.2.1.4-1.

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 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 due to the following ARDMs are treated as “plausible” and should be managed for the HVAC systems associated with the auxiliary building, 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 Aging Management Review

To expedite the AMR and 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 partially 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 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 the housings for fans in the SRW heat exchanger room are constructed of aluminum.

With regard to the environmental condition of the auxiliary building, the applicant states 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 to 120 ºF, except in the main steam penetration area where the temperature is around 160ºF. 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 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.

All of the above-mentioned components are exposed to moisture.

Control Room

In Section 5.11C, 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 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 and, therefore, the external surfaces are not exposed to the weather or sunlight. The control room

maximum area temperature for normal operating conditions is 110 ºF 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 identifies 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 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 current licensing basis (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

Modified Existing Programs

- CCNPP Administrative Procedure MN-319, “Structure and System Walkdowns” (modified program)
- CCNPP Modified Existing Procedure to Include Specific Items with Respect to Discovery of ARDMs

The combined application of these three programs will be credited for (a) discovery and management of the effects of crevice 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.

CCNPP Age-Related Degradation Inspection Program

- The system walkdowns can identify degradation evident externally from the components. An inspection of the internals would provide additional assurance that the effects of elastomer degradation and wear are being adequately managed. This inspection will be accomplished as part of an ARDI Program.

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 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 Preventive Maintenance Programs

- Preventive Maintenance 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.
- Preventive Maintenance 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.
- Preventive Maintenance Checklist MPM04111 is to be used for the discovery, and management of the effects of radiation damage, elastomer degradation, and wear of damper seals.
- Preventive Maintenance 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.
- 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

Existing CCNPP Maintenance Programs

- Preventive Maintenance 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.
- Preventive Maintenance 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.
- 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 current licensing basis (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 included 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 related 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 subsections.

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, cooling coil housings, etc.) 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 states 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 ºF to 120 ºF, except in the main steam penetration area where the temperature is around 160 ºF.

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 3.11C-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, 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 cites over 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 states 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, balancing fans, and installing flexible collars or cloth boots to minimize vibration. The applicant also modified the existing preventive maintenance 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.

Based on its review of previous records and analysis of operating experience, the applicant determined that the effects of corrosion (crevice corrosion, general corrosion, and pitting) for duct and 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 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 due to 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 seat of the valves could impair the functioning of the valves.

3.6.3.2 Aging Management Programs for License Renewal

The staff evaluation of the applicant's AMPs was focused on program elements rather than on 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 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.

<u>Scope of Program</u>

The staff had some questions about the exclusion of certain components (e.g., containment air cooler lowdown door fusible links, electric hydrogen recombiners) from the scope of license renewal. The applicant explained that such components were excluded because (1) they were active components, and were not within the the scope of license renewal, (2) they were non-safety-related, and did not impact the functioning of other safety-related structures, systems, and components, or (3) they were evaluated under other sections of the LRA. The staff agreed with the applicant's explanations. The staff concludes that the aging management programs for the H&V and HVAC system device types is acceptable because an appropriate scope of system structures and components is covered by the existing and modified inspection and maintenance activities.

<u>Corrective Actions</u>

The applicant's preventive maintenance program was established to maintain plant equipment, structures, systems, and components in a reliable condition for normal operation and emergency use; minimize equipment failure; and to extend equipment and plant life. The program covers all preventive maintenance 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 the developing and enhancing of 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 preventive maintenance 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, the applicant has existing programs 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 review of the walkdown procedure, MN-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 supplement 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 technique, 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 procedure 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 AMR. The staff evaluation of the applicant's corrective action program is provided separately in Section 3.1.5 of this SER. On the basis of this evaluation, the staff concludes that the applicant has provided 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 states that over 20 years of operating experience from HVAC duct cracking ducts due to vibration, fan imbalance, loosening of fasteners, and minor corrosion of cooling coils have been experienced. The corrective actions included addition of supports, balancing of fans, and monitoring of corrosion rates. Based on the operating experience described in Sections 5.11A, 5.11B, and 5.11C, 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

Based on the 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 buildings 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 provided by the applicant in response to the staff RAIs. Except for the confirmatory item identified in this SER section, 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 that 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

BGE (the applicant) described its aging management review (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 provided 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 licensee to discuss and resolve issues pertaining to EDG systems.

3.7.2 Summary of Technical Information in 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 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 all 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 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 identified 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 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 (corrosion fatigue and 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 aging management programs (AMPs) for the EDG systems:

- CCNPP Plant Evaluation Guideline, "System Walkdowns," PEG-7 (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-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 current licensing basis (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 indicates that 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 included 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 renewal AMR, it is reasonable to expect similar degradation as a result of corrosion in the components within the scope of license renewal review. 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 licensee 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 (The applicant letter to NRC dated 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. The staff finds this explanation acceptable.

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 direct exposure of 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 (the applicant 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 to be greater than the minimum specification requirement of 0.25 inch. The muffler internal surfaces were in good condition, and there was no evidence of any age-related degradation. The staff finds this explanation acceptable.

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 addresses corrosion on external and internal surfaces of components.

3.7.3.1.1.1 Corrosion of External Surfaces

The above-ground piping material 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 preventive maintenance programs to inspect for coating degradation as aging management of corrosion of the external surfaces of EDG system components for license renewal. Except for the specific items discussed below, the staff finds this aging management program acceptable 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). The staff disagrees 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. Therefore, the staff finds that the applicant needs to identify both coatings and cathodic protection for buried pipelines to be within the scope of license renewal. This is Open Item 3.7.3.1.1.1-1.

The staff also asked that the applicant describe the degree of compliance with NACE RP 01-69 (92), which describes methods to determine the effectiveness of coatings and cathodic protection programs. The applicant responded that age-related degradation of the external surfaces of the buried DFO piping will be managed by a new Buried Pipe Inspection Program, which is being developed. The staff reviewed the summary of the Buried Pipe Inspection Program and found it to acceptable.

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 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). Inspections of buried pipe occur 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 buried pipe inspections locations are based on previous inspections and are not on a regular schedule. An inspection of selected areas of buried pipe will be conducted during the last 5 years of the current operating licenses. (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 detectible 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 made three excavations of buried DFO system piping 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 to be in pristine condition after approximately 20 years of service.

With the exception of the open item previously identified, 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 FOSTs and internals is carbon steel. The internal surfaces of the FOSTs are covered with a protective coating of a self-curing, inorganic zinc primer (trade name 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's evaluation of the applicant's DFO chemistry program is discussed separately in Section 3.1.2 of this staff SER.

The applicant proposed a new program for inspecting the FOST internal surfaces 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 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 on external surfaces 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 on a periodic basis. 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 detectible by visual techniques and other techniques, such as those based on national codes and standards; (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 procedures are effective. Specifically, on November 1, 1995, the applicant inspected Number 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 internal surfaces was found to be intact, no contact between the system fluid and the internal surfaces of the tank is occurring. The inspection concluded that there were no observed deficiencies during tank visual (interior and exterior) inspections 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 of tank surfaces was found. On April 13, 1997, the applicant inspected Number 21 FOST and found it to be in similarly good condition.

The staff finds the use of these programs by the applicant to be acceptable because (1) this program scope includes the external 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 external 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 PEG-7, MN-3-100, and OL-2-00.

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 preventive maintenance 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 preventive maintenance programs will be modified to include the components subject to AMR and inspection for 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 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 detectible 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 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 these actions taken by 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 provided enough information in Appendix A to the LRA to show that the ARDI Program is an effective AMP for detecting corrosion damage in the above-mentioned systems.

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. The staff disagrees with this conclusion because the applicant has stated in Appendix A to the LRA that no credit is taken for cathodic protection in its evaluation of aging effects. In an 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 NACE Standard RP 0193 (93), "External Cathodic Protection of On-Grade Metallic Storage Tank Bottoms," for managing aging effects on the FOST bottoms. The applicant does have Procedure MN-1-319, "Structure and System Walkdowns," which is credited to discover age-related degradation of the external surfaces of the FOST shell. Operating experience, combined with the results of ultrasonic examinations, indicates that corrosion of the FOST bottoms is not subject to any applicable aging effects. Based on the above discussion, the staff agrees that no aging management of the FOST shell is required.

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 preventive maintenance and a new inspection program to manage fatigue for these components for the period of extended operation. Appendix A to the LRA indicates that preventive maintenance 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 concluded 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 of 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 due to the presence of particles in the high-temperature fluid (liquid or gas) moving with high velocities relative to the affected components. Because during the EDG operation hot exhaust gases may erode certain portions of the muffler, there is a possibility for an ARDM to occur. The applicant does not have any 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 provided 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.

In view of the discussion above, 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 for License Renewal

The staff evaluated the applicant's following AMPs to determine whether the 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)

Appendix A to the LRA indicated that corrective actions for license renewal will be conducted in accordance with programs meeting the requirements of 10 CFR Part 50, Appendix B, and cover all structures and components subject to AMR. Appendix B of Part 50 to 10 CFR, 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 AMR whether they are safety-related or not. The staff considers this approach to be acceptable because corrective actions implemented under Appendix B should be sufficient to maintain the applicant's CLB for the EDG components.

3.7.3.3 Time-Limited Aging Analyses

Appendix A to the LRA indicates that there are no TLAAs applicable to the EDG systems. The staff evaluation of the applicant's identification of TLAAs is provided separately in Section 4 of this staff 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 provided by the applicant in response to the staff RAIs. On the basis of this review, as previously stated, the staff concludes that with the exception of the open item previously identified, the applicant has provided an acceptable demonstration that the aging effects associated with the EDG systems will be adequately managed so that there is reasonable assurance that 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

BGE (the applicant) described its AMR of the SPCSs for license renewal in the following three sections of its 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” of Appendix A, “Technical Information,” 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 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 Provided in The Application

3.8.2.1 Structures and Components Subject to an Aging Management Review (AMR)

Section 5.1 of Appendix A to the LRA describes 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 ºF 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, flow elements and orifice, current/pneumatic device, pump, tank, and turbine.

Section 5.9 of Appendix A to the LRA describes 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, and temperature elements.

Section 5.12 of Appendix A to the LRA, describes the main steam, SG blowdown, extraction steam, and nitrogen and hydrogen systems in detail. Specifically, 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 prior to its entering 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 consists of two independent systems supplying gases for normal plant operations. The applicant determined that the following device types require an AMR: piping, accumulators, valves, 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 due to the following "plausible" ARDMs should be managed for license renewal: cavitation erosion, corrosion, erosion/corrosion, wear, 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 is as 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.

●	Group 1 — Cavitation Erosion of AFW Piping
	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 ºF. 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 steels, alloy steel, and stainless steel.
●	Group 4— External Surface Corrosion of Buried Pipe

●	Group 1 — Cavitation Erosion of AFW Piping
	Group 4 consists of piping that is buried in soil or embedded in concrete and whose external surfaces are subject to crevice corrosion, general corrosion, microbiological by 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 ºF, 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 of the following materials: alloy, chromium-molybdenum, carbon, and stainless steels.
●	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 1 — Cavitation Erosion of AFW Piping
	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.

Feedwater System

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; and
- Group 3— erosion/corrosion for piping, check valves, MOVs, and temperature elements.

A more detailed description of the component materials, environments, and ARDMs follows.