Safety Evaluation Report

With Open Items Related to the License Renewal of the Edwin I. Hatch Nuclear Plant, Units 1 and 2

Docket Nos. 50-321 and 50-366

Southern Nuclear Operating Company, Inc.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

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ABSTRACT

This safety evaluation report (SER) documents the technical review of the Edwin I. Hatch Nuclear Plant (Plant Hatch), Unit Nos. 1 and 2, license renewal application (LRA) by the U.S. Nuclear Regulatory Commission staff (staff). By letter dated February 29, 2000, Southern Nuclear Operating Company, Incorporated (SNC or the applicant) submitted the LRA for Plant Hatch in accordance with Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54 or the Rule). SNC is requesting renewal of the operating licenses for Unit 1 and Unit 2 (license numbers DPR-57 and NPF-5) for a period of 20 years beyond the current expiration of midnight, August 6, 2014 and midnight, June 13, 2018, respectively.

The Plant Hatch site is located in Appling County, Georgia, approximately 67 miles southwest of Savannah, Georgia. Construction began on Unit 1 in 1969 and its operating license was issued in 1974. Construction began on Unit 2 in 1972 and its operating license was issued in 1978. Each unit consists of a General Electric (GE) boiling-water reactor (BWR) nuclear steam supply system designed to generate 2558 MW-thermal, or approximately 800 MW-electric.

This SER presents the status of the staff's review of information submitted to the NRC through January 31, 2001, 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 the open items. The staff will present its final conclusion on the review on the Plant Hatch LRA in its update to this SER.

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1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is an SER on the application for license renewal for the Edwin I. Hatch Nuclear Power Plant Unit Nos. 1 and 2 (Plant Hatch), as filed by Southern Nuclear Operating Company (SNC or the applicant). By a letter dated February 29, 2000, SNC submitted its application to the United States Nuclear Regulatory Commission (NRC) for renewal of the Plant Hatch operating licenses for an additional 20 years. The NRC staff (the staff) prepared this report and summarizes the results of its 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 the Plant Hatch license renewal review is William F. Burton. Mr. Burton may be contacted by calling 301-415-2853, or by writing to the License Renewal and Standardization Branch, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001.

In its February 29, 2000 submittal letter, SNC requested renewal of the operating licenses issued under Section 104 and Section 103 of the Atomic Energy Act of 1954, as amended, for Unit 1 (license number DPR-57) and Unit 2 (license number NPF-5), respectively, for a period of 20 years beyond the current license expirations of midnight, August 6, 2014 for Unit 1 and midnight, June 13, 2018 for Unit 2. Plant Hatch is located in Appling County, Georgia, approximately 67 miles southwest of Savannah, Georgia. Construction began on Unit 1 in 1969 and its operating license was issued in 1974. Construction began on Unit 2 in 1972 and its operating license was issued in 1978. Each unit consists of a General Electric (GE) boiling-water reactor (BWR) nuclear steam supply system designed to generate 2558 MW-thermal, or approximately 800 MW-electric. Details concerning the plant and the site are found in the Final Safety Analysis Reports (FSAR) for the units.

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 Plant Hatch license renewal is based on SNC’s license renewal application (LRA) and on the answers to requests for additional information (RAIs) from the staff. In meetings and docketed correspondence, SNC has also supplemented its answers to the RAIs. Unless otherwise noted, the staff reviewed and considered information submitted through January 31, 2001. Information received after that date was reviewed on a case-by-case basis, depending on the stage of the safety review. The LRA and all pertinent information and materials, including the FSAR mentioned above, are available to the public for review at the NRC Public Document Room, 11555 Rockville Pike, Room 1-F21, Rockville, MD, 20852-2738 (301-415-4737/800-3974209), and at the Appling County Library, 242 East Parker St., Baxley, Georgia 31513. Material related to the LRA is also available through the NRC’s website, at http://www.nrc.gov/NRC/REACTOR/LR/index.html.

This SER summarizes the results of the staff’s safety review of the Plant hatch LRA 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 LRA was reviewed in accordance with the NRC regulations and the guidance provided in the NRC draft “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants, “ dated September 1997 (SRP-LR).

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 in Section 6.

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

In accordance with 10 CFR Part 51, the staff will prepare a draft for comment, and a final plant-specific supplement to the generic environmental impact statement (GEIS) that discusses the environmental considerations related to renewing the licenses for Plant Hatch. The plant-specific supplement 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). On the basis of 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 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 10 CFR Part 54 established a regulatory process that is expected to be simpler, more stable, and more predictable than the previous license renewal rule. In particular, 10 CFR 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 (SSCs) 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 (SCs).

In parallel with these efforts, the NRC pursued a separate rulemaking effort, 10 CFR Part 51, to focus the scope of the review of environmental impacts of license renewal, in fulfilling 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 in two key principals:

(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 SSCs in the period of extended operation, and possibly a few other issues related to safety during the period of extended operation.

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

In implementing these two principles, the rule in 10 CFR 54.4 defines the scope of license renewal as those SSCs (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 SSCs within the scope of the rule to identify SCs subject to an AMR. SCs subject to an AMR are those that perform an intended function without moving parts or without a change in configuration or properties and that are not subject to replacement based on qualified life or specified time period. 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 SCs will be maintained, consistent with the current licensing basis, 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 through 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 (TLAAs). During the design phase for a plant, certain assumptions are made about the length of time the plant will be operated and these assumptions are incorporated into desgin calculations for several of the plant's SSCs. Under 10 CFR 54.21(c)(1), these calculations must

be shown to be valid for the period of extended operation or must be projected to the end of the period of extended operation, or the applicant must demonstrate that the effects of aging on these SSCs 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 License.” 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 GEIS, 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 CFR 51.53(c)(3)(i), an applicant for license renewal may incorporate these generic findings in its environmental report. Analyses of those environmental impacts that must be evaluated on a plant-specific basis, Category 2 issues, must be included in the environmental report in accordance with 10 CFR 51.53(c)(3)(ii).

In accordance with NEPA and the requirements of 10 CFR Part 51, the NRC performed a plant-specific review of the environmental impacts of license renewal, including whether there was new and significant information not considered in the GEIS. A public meeting was held on May 10, 2000, near Plant Hatch as part of the NRC scoping process to identify environmental issues specific to the plant. Results of the environmental review and a preliminary recommendation with respect to the license renewal action are documented in NRC’s draft plant-specific supplement to the GEIS, which was issued by the NRC on November 3, 2000, and which was discussed at a separate public meeting held on December 12, 2000 in Vidalia, GA. After consideration of comments on the draft, NRC will prepare and publish a final plant-specific supplement to the GEIS. These documents are published separate from this report.

1.3 Summary of Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the Plant Hatch LRA in accordance with Commission guidance and the requirements of 10 CFR 54.19, 54.21, 54.22, 54.23, and 54.25. The standards for renewing a license are contained in 10 CFR 54.29. This SER describes the results of the staff’s safety review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. SNC provided this general information in Section 1 of its LRA for Plant Hatch, submitted by letter dated February 29, 2000. The staff finds that SNC has submitted the information required by 10 CFR 54.19(a) in Section 1 of the LRA.

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." SNC states the following in its LRA regarding this issue:

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

The staff intends to maintain the license numbers on issuance of the renewed license. Therefore, there is no need to make conforming changes to the indemnity agreement, and the requirements of 10 CFR 54.19(b) have been met.

In 10 CFR 54.21, the Commission requires that each application for a renewal license for a nuclear facility must contain the following information: (a) an IPA, (b) current licensing basis (CLB) changes during NRC review of the application, (c) an evaluation of TLAAs, and (d) an FSAR supplement. Sections 3 and 4, and Sections A and B of the LRA, address the license renewal requirements of 10 CFR 54.21(a), (c), and (d), respectively.

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. SNC addresses the requirements of 10 CFR 54.22 in Appendix E of the LRA.

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 SRP. The staff's evaluation of the LRA in accordance with 10 CFR 54.21 and 54.22 is 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 Plant Hatch. These documents will be prepared by the staff separate from this report. When the report of the Advisory Committee on Reactor Safeguards (ACRS), required by 10 CFR 54.25, is issued, it will be incorporated into Section 5 of this SER. The findings required by 10 CFR 54.29 will be placed in Section 6 of this report.

1.3.1 Boiling Water Reactor Vessel Internals Project (BWRVIP) Topical Reports

In accordance with 10 CFR 54.17(e), SNC also incorporated by reference several BWRVIP topical reports into the Plant Hatch LRA. The purpose of the topical reports is to generically demonstrate that the aging effects for reactor coolant system components are adequately managed for the period of extended operation under a renewed license. Specifically, SNC incorporated the following BWRVIP topical reports into its application:

- BWRVIP-05, “BWR RPV Shell Weld Inspection Recommendations,” September 1995
- BWRVIP-06, “Safety Assessment of BWR Reactor Internals,” October 1995
- BWRVIP-18, “Core Spray Internals Inspection and Flaw Evaluation Guidelines,” July 1996
- BWRVIP-26, “Top Guide Inspection and Flaw Evaluation Guidelines,” December 1996
- BWRVIP-27, “Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines,” April 1997
- BWRVIP-38, “Shroud Support Inspection and Flaw Evaluation Guidelines,” September 1997
- BWRVIP-41, “BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines,” October 1997
- BWRVIP-47, “BWR Lower Plenum Inspection and Flaw Evaluation Guidelines,” December 1997
- BWRVIP-48, “Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines,” March 1998
- BWRVIP-60, “Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals,” March 1999
- BWRVIP-62, “Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection,” December 1998
- BWRVIP-74, “BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines,” September 1999.
- BWRVIP-75, “Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313),” October 1999
- BWRVIP-76, “BWR Core Shroud Inspection and Flaw Evaluation Guidelines,” December 1999

- BWRVIP-78, “BWR Integrated Surveillance Program - Unirradiated Charpy Reference Curves for Surveillance Material,” December 1999

All the BWRVIP reports listed above have been approved by the staff, with the following exceptions:

- BWRVIP-62: a safety evaluation has been issued with open items
- BWRVIP-74: staff is writing the final safety evaluation
- BWRVIP-75: a safety evaluation has been issued with open items
- BWRVIP-76: incorporates BWRVIP-07 and 63. Staff has issued its safety evaluation with open items for BWRVIP-63 and is awaiting a response from the BWRVIP.
- BWRVIP-78: staff is awaiting supplemental information in response to an RAI. The staff expects that the RAI response will provide adequate technical justification to approve the proposed integrated surveillance program

1.4 Summary of Open Items

As a result of its review of the LRA for Plant Hatch, including additional information submitted to the NRC through January 31, 2001, the staff identified the following issues that remained open at the time this report was prepared. An issue is open if SNC has not presented a sufficient basis for resolution. Each open item has been assigned a unique identifying number which identifies the section in this report in which the open item is described. For example, Open Item 3.0-1 is discussed in Section 3.0 of this report.

Item	Description
2.1.3.1-1	The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4 (a)(1)(i), (ii), or (iii). In Section 2.1.2.5 of the LRA, the applicant stated that the few cases where non-safety-related components could impact safety-related functions were included in the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2). In the staff’s requests for additional information (RAIs) 3.4-11 and 3.6-51, dated July 28, 2000, the staff requested that the applicant clarify whether the scope of the auxiliary systems discussed in Section 3.2.4 of the LRA includes any spatially-related components and piping segments within the category of “Seismic II Over I” (a non-seismic Category SSC whose failure could cause loss of safety function of a seismic Category I SSC). In addition, the staff requested that the applicant clarify how the aging management programs for the non-safety-related systems and components have been addressed. Specifically, the staff requested the applicant to state whether the same aging management programs discussed in Table 3.2.4 of the LRA also apply to the seismic II over I piping components. The applicant responded to these RAIs in its letter dated

October 10, 2000. The applicant stated that the pipe supports for the seismic II over I piping systems are within the scope of license renewal and thus the supports for the seismic II over I piping systems are included within the scope of the aging management programs identified in the LRA. However, the applicant also stated that no aging management programs are applied to out-of-scope piping segments with seismic II over I piping supports. In a telephone conversation on October 24, 2000, the applicant further clarified this point. The applicant stated that within the context of the Plant Hatch licensing basis, non-safety-related piping systems are postulated to fall in a seismic event if not seismically supported. Thus, for the protection of safety-related piping, some non-safety-related piping is seismically supported. Those seismic supports are within the scope of license renewal, but the applicant does not consider the seismic II over I piping segments to be within the scope of license renewal. The staff does not agree with the applicant's scoping criteria for seismic II over I piping systems. The staff's position is that the seismic II over I piping whose failure could prevent safety-related systems and structures from accomplishing their intended functions should be within the scope of license renewal. The staff considers the seismic II over I piping segments to be within the scope of license renewal. This issue is also discussed in Section 3.6.3.2 of this SER.

2.3.3.2-1 (a) In RAI-2.3.3-HR-1 and RAI-2.3.3-HR-4, the staff asked the applicant to justify its exclusion of the following components (highlighted in HL-26068) from an AMR: water separator, water spray cooler, reaction chamber, blower (C0001A), heater (B001A), and instrument tubing. The applicant responded that these components are a part of skid-mounted hydrogen recombiners, which are active components, and thus not subject to an AMR. Therefore, the applicant determined that the components are also not subject to an AMR.

In a telephone conference, dated September 13, 2000, the staff expressed its disagreement with the applicant's determination to exclude these components from an AMR simply because these components are skid-mounted. The staff requested the applicant to provide additional justification for its position. In response, the applicant provided a paper, entitled "Active Assemblies Used in License Renewal," via an email, dated November 6, 2000.

The staff has reviewed this paper, and finds that the applicant's basis for excluding hydrogen recombiner components, as discussed in the paper, is not consistent with the license renewal rule. The basis for the staff's conclusion summarized below and is described in more detail in Section 2.3.4.2 of this report discussing the emergency diesel generators.

Components are subject to an AMR if they perform a passive function and are long-lived. A passive function is one performed without moving parts or a change in configuration or properties. A function performed with moving parts or a change in configuration or properties is considered

an active function. Components that perform a passive function and are also long-lived must be subject to an AMR, whether they are skid-mounted or not. The staff believes that the water separator, water spray cooler, and reaction chamber are long-lived components with a passive function, and therefore are subject to an AMR. On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components performing a passive function associated with the hydrogen recombiners, and identify AMPs credited with managing the aging effects.

(b) In reviewing drawings HL-21074, HL-11631, HL-11638, the staff found that some of the pumps were highlighted as within the scope of license renewal, but there are no pumps listed in Table 2.3-12 as subject to an AMR. The staff requested the applicant to explain this discrepancy. The applicant explained that on drawings HL-11638 (sheets 1 and 2) and HL-11631 (sheets 1 and 2), all the pumps are part of the diesel generator skid. The applicant further stated that the diesel generator is an active component and, thus, not subject to an AMR. Therefore, the applicant determined that these pumps, which are part of the diesel generator skid, are also not subject to an AMR. However, the pumps that are not part of the diesel generator skid (on drawing HL-21074) are subject to an AMR and appear in Table 2.3.4-19 of the LRA for the fuel oil system. The staff does not agree that pumps can be excluded from an AMR because these pumps are part of the diesel generator skid that constitutes part of a complex assembly.

In a telephone conference on September 13, 2000, the staff expressed its disagreement with the applicant's decision to exclude these components from an AMR simply because these components are skid-mounted. The staff requested the applicant to provide additional justification for its position. In response, the applicant provided a paper, entitled "Active Assemblies Used in License Renewal."

The staff has reviewed this paper and does not agree with the applicant's basis for excluding skid-mounted components that are part of a complex assembly from an AMR.

Regarding complex assemblies, NEI 95-10, Revision 0, stated:

> "There are structures and components that, when combined, are considered a complex assembly (e.g., diesel generator starting air skids or heating, ventilating, and air conditioning refrigerant units). The Rule and associated SOC do not specifically discuss such assemblies. For purposes of performing an aging management review, it is important to clearly establish the boundaries for review. An applicant should establish the boundaries for such assemblies by identifying each structure or component that makes

up the complex assembly and determining whether or not each structure and component is subject to an aging management review. (See example 5 in Appendix C.)"

Example 5 in Appendix C of NEI 95-10, Revision 0, provided an example of a control room chiller complex assembly and guidance on how to establish the boundaries for such an assembly. It notes that once the boundary is determined, long-lived components with a passive function would be appropriately subjected to an AMR.

Components are subject to an AMR if they perform a passive function and are long-lived. A passive function is one performed without moving parts or a change in configuration or properties. A function performed with moving parts or a change in configuration or properties is considered an active function. Components that perform a passive function and are also long-lived must be subject to an AMR, whether they are skid-mounted or not. The staff believes that the water separator, water spray cooler, and reaction chamber are long-lived components with a passive function, and therefore are subject to an AMR. On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components performing a passive function associated with the hydrogen recombiners, and identify AMPs credited with managing the aging effects.

In the staff's evaluation of the Oconee LRA, the staff reached a similar conclusion regarding the treatment of the vendor-supplied diesel generator skid-mounted equipment. Duke had drawn an enclosure around the diesel generator skid and determined that everything within the enclosure was active and therefore not subject to an AMR. The staff disagreed and noted that the assembly included some long-lived components with a passive function which were subject to an AMR. Duke subsequently redefined the evaluation boundaries to ensure that long-lived components with a passive function on the diesel generator skid were subject to an AMR.

On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components with a passive function associated with the emergency diesel generators, and identify AMPs credited with managing the aging effects.

2.3.3.2-2 (a) In its responses to RAI 2.3.3-SGTS-1 and RAI 2.3.3-SGTS-2, the applicant stated that differential pressure indicators, guillotine damper housings, and fan housings in the SGTS are not subject to an AMR based on NEI 95-10, Appendix B guidance. The staff agrees that differential pressure indicators are considered components with an active function and, therefore, are not subject to an AMR. However, the staff questioned whether it was appropriate for the applicant to exclude

guillotine damper housings and fan housings from an AMR. During a telephone conference (telecon) on October 31, 2000, the staff asked the applicant to provide justification for why the housings for the guillotine dampers and fans should be excluded from an AMR.

In response to staff concerns regarding the exclusion from an AMR of the housings for components such as fans, dampers, and heating and cooling coils, the applicant provided, by an e-mail dated November 6, 2000, a paper titled "Active Assemblies Used in License Renewal."

The staff has reviewed this paper and finds that the applicant's basis for excluding fan, damper, and heating and cooling coil housings is not consistent with the license renewal rule, the Statements of Consideration (SOC) accompanying the license renewal rule in 10 CFR Part 54, and the staff's review guidance.

10 CFR 54.21(a)(1) provides that those components that perform their intended functions without moving parts and without a change in configuration or properties (10 CFR 54.21(a)(1)(i)) and that are not subject to replacement based on qualified life or specified time period (10 CFR 54.21(a)(1)(ii)) are subject to an AMR. Such components are commonly considered as "long-lived" and as performing a passive function. 10 CFR 54.21(a)(1)(i) states that "structures and components [with passive functions] include, but are not limited to,... pump casings, valve bodies ... " and lists other components that perform passive functions. The examples cited in the rule illustrate components with significant passive functions.

The SOC, in Section III.f.i(a), further explains that major components may have active functions, passive functions, or both, and cites pumps and valves as examples (SOC Section III.f.i.(a)). Pumps and valves have moving parts, but the Commission concluded that the pressure-retaining function performed by the pump casing and the valve body were important enough to warrant an AMR. The SOC further explains that the Commission does not limit the consideration of pressure boundaries to reactor coolant pressure boundary. The exclusion regarding components is focused on active functions rather than on the exclusion of the entire component, while the AMR applies to the passive function of the component. On this basis, the staff concludes that fans, dampers, and heating and cooling coils may include significant passive pressure-retaining and structural support functions.

Section 2.2.III.A of the draft SRP-LR, September 1997, states that "...some functions of "active" components may meet the criteria of the "passive" description. For example, although a pump or a valve has some moving parts, a pump casing or valve body performs a pressure retaining function without moving parts. A pump casing or a valve body meets this description and would therefore be considered for an aging

management review." It is clear by this passage, and by the examples provided of pumps and valves, that the passive functions of components are subject to an AMR.

In Section 2.1.1 of the LRA, the applicant states that the specific method used to identify in-scope functions and to screen the SSCs required to perform the in-scope functions was developed considering the guidance provided by NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," among other regulatory and guidance documents. Appendix B of NEI 95-10 provides a list of components and their active/passive functions. Item numbers 155 and 163 identify dampers and ventilation fans, respectively. Each of these components is identified in the appendix as performing an active function. The staff notes that the appendix, though it specifically identifies the dampers and ventilation fans, does not address housings for these components.

On the basis of the information in the regulation, the SOC, and guidance provided in the SRP-LR, the staff concludes that the housings for fans, dampers, and heating and cooling coils contribute to the performance of the intended function of fans, dampers, and heating and cooling coils without moving parts and without a change in configuration or properties, and thus are subject to an AMR. This issue also affects the scope of components with passive functions for the control building HVAC, outside structures HVAC, and reactor building HVAC systems, which are discussed in Section 2.3.4.2 of this SER.

Therefore, based on the above staff positions, the staff requests that the applicant identify the passive functions for those fans, dampers, and heating and cooling coils that are within the scope of license renewal. For those passive functions, the applicant should identify any aging effects associated with the components and provide an AMP to manage the aging.

The applicant also agreed to clarify the function of the guillotine damper regarding whether this damper is safety-related and included in the scope of license renewal and subject to an AMR.

(b) In its response to RAI 2.3.4-CBHVAC-1, the applicant also stated that no damper housing, fan housing, and air handling units, including the cooling coils, are found within the license renewal portions of the control building HVAC system based on NEI 95-10, Appendix B guidance. The staff disagrees with the applicant's exclusion from an AMR of housings for fans, dampers, and air handling units, including cooling coils. The staff's position with regard to the treatment of the housings for fans, dampers, and heating and cooling coils is discussed in detail in the staff's review of

the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER applies to the treatment of the component passive functions of the control building HVAC system.

Additionally, in a telephone conference (telecon) held on October 31, 2000, the applicant clarified that the LPCI inverter room and the Unit 2 vital A/C room coolers are no longer in scope due to a design modification. The applicant committed to provide a description of the design modification that clarifies how the modification impacts the LPCI inverter room and Unit 2 vital A/C room functions. The applicant also committed to address why heating coil housings are not specifically identified in Table 2.3.4-20 of the LRA.

(c) In its response to RAI 2.3.4-OSHVAC-1, the applicant stated that roof-mounted exhaust ventilator housings and wall-mounted unit heater housings are not subject to an AMR, since these housings are part of active components (i.e., fan/damper assembly and heater for each, respectively). The staff disagrees with the applicant's exclusion from an AMR of roof-mounted exhaust ventilator and wall-mounted unit heater housings. The staff's position with regard to the treatment of the housings for roof-mounted exhaust ventilators and wall-mounted unit heaters is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER also applies to the treatment of the component passive functions of the outside structures HVAC system.

(d) In its response to RAI 2.3.4-RBHVAC-1, the applicant stated that safeguards equipment room cooler housings are not subject to an AMR, based on NEI 95-10, Appendix B guidance. With regard to this RAI, the applicant also did not address the scope of license renewal and an AMR as relates to air-operated valve bodies, air-operated damper housings, and associated ductwork. Additionally, in a telephone conference (telecon) held on October 31, 2000, the applicant agreed to reconsider its response to RAI 2.3.4-RBHVAC-3, concerning whether certain ductwork identified by the staff is within the scope of license renewal and is subject to an AMR.

The staff believes that the safeguards equipment room cooler housings may be within the scope of license renewal and subject to an AMR. The staff's position with regard to the treatment of the housings for the safeguards equipment room coolers is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER applies to the treatment of the component passive functions of the reactor building HVAC system. Resolution of this issue, including the scoping clarification for the air-operated valve bodies, air-operated damper housing, and associated ductwork, is part of this open item.

2.3.4.2-1 With respect to the radwaste building, the staff reviewed the Plant Hatch FHA dated July 22, 1986 and concludes that fire suppression for certain areas in the radwaste building were included in the 1986 FHA. Specifically, Section IV.B.4.d of the FHA states that "fixed automatic water spray systems are installed in all charcoal filters in the plant". The radwaste building contains charcoal filters which are protected by fixed sprinkler systems. Therefore, the fire suppression piping leading to the charcoal filters, including the nozzles and sprinkler heads, should be included within the scope of license renewal and subject to an AMR.

In addition, Section IV.D of the FHA states that the guidelines for specific plant areas is presented for each specific plant area throughout the FHA. In both the 6/86 and 7/87 revisions to the FHA, the FHA analysis of fire area/zone 2301 (Radwaste Building - All Elevations) states that , "all sections of this area which contain specific fire hazards (charcoal filters) or high concentrations of combustibles (dry waste storage area, Radwaste Control Room) are equipped with detection, suppression, or both." Specifically, the west central portion of fire zone 2301J over the drywaste storage section is equipped with a wet pipe suppression system. To the staff's knowledge, the applicant has not submitted any information to the staff to show that the radwaste suppression system has been physically removed or altered so that it can't perform it's intended function and that no plant evaluations through 50.59 have determined that this suppression system is no longer required for compliance with Appendix A to BTP 9.5-1.

Therefore, it is the staff's view that the radwaste suppression system should be included within the scope of license renewal and subject to an AMR.

3.0-1 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. Therefore, the resolution of the information that needs to be added to the FSAR supplement will be addressed after the other open items are resolved, prior to the issuance of the renewed license.

3.1.1-1 The applicant's reactor water chemistry control program is based on the guidance provided in EPRI TR-103515, "BWR Water Chemistry Guidelines." In the staff's RAIs regarding program elements that deviate from the referenced EPRI guidelines, the applicant indicated that this program meets the guidelines of EPRI TR-103515, Revision 2. The staff notes that EPRI TR-103515, Revision 2, has not been approved by the staff for generic use. Therefore, the applicant should clarify the differences between Revision 1 and Revision 2 of EPRI TR-103515, so the staff can determine whether the provisions of Revision 2 are acceptable.

3.1.3-1 The diesel fuel oil testing program, like the various chemistry control programs in effect at Plant Hatch, is a mitigative activity which is not intended to directly detect age-related degradation. The implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program. Steel storage tanks are

susceptible to corrosion from the outside by contact with the earth unless an effective cathodic protection system is employed. The applicant does not take credit for such a system. Also, water in the fuel oil will be in contact with the tank bottom, possibly causing corrosion. The diesel fuel oil testing program will not be able to detect such degradation. Therefore, the staff concludes that a one-time inspection program is warranted for the diesel fuel oil tanks to verify tank bottom thickness. The addition of a one-time inspection program for the tanks would be consistent with the applicant's approach for other chemistry control programs at Plant Hatch. For example, the torus submerged components inspection program complements the applicant's suppression pool chemistry control. Also, the condensate storage tank inspection complements the applicant's demineralized water and condensate storage tank chemistry control program. The staff requests the applicant provide specific attributes of an inspection program, consistent with other one-time inspections (e.g., inspection scope, inspection technique, acceptance criteria, etc.).

3.1.11-1 The application stated that the plant commodity group in the scope for this activity is class 1 pressure boundary bolting and non-class 1 pressure boundary bolting. Class 1 pressure boundary bolting is fabricated from low alloy steel. The non-class 1 pressure boundary bolting is fabricated to the requirements of ASTM A-307 (Grade B), ASME SA-194 (Grade 2H), and ASME SA-193 (Grade B7). Bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. In response to RAI 3.4-1, the applicant did not state if the yield strength for ASME SA-193 (Grade B7) or any other bolts are limited to less than 150 ksi to avoid the possibility of stress corrosion cracking. See RICSIL No. 055, February 1, 1991, "RPV Head Stud Cracking." The staff requests the applicant to provide this information.

3.1.13-1 (a) In Section C.2.4.3 of the LRA, the applicant credits the PSW and RHRSW inspection program with managing the aging effects of RHR and PSW components exposed to a buried environment. The inspection program includes provisions for cleaning, priming, coating, and wrapping underground pipelines whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping. However, this aspect of the program is not discussed in Sections A.1.13 or B.1.13 of the LRA. The staff requests the applicant enhance its description of the PSW and RHRSW inspection program to clearly state that the scope of the program includes this particular aspect for managing aging effects associated with a buried environment, consistent with the discussion in Section C.2.4.3 of the LRA.

(b) In Table 3.2.3-2 of the LRA, the RHR heat exchanger augmented inspection and testing program is credited with managing, in part, aging effects for various heat exchanger components, including the tubes, tubesheet, and shell. However, the description of the PSW and RHRSW inspection program contained in Section B.1.13 of the LRA includes several references to inspections of heat exchanger components. The

staff requests that the applicant clarify the scope of the PSW and RHRSW inspection program relative to managing aging effects for the various heat exchanger components listed in Table 3.2.3-2 of the LRA.

(c) The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with Division I PSW piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and AMPs are consistent with other piping sections in this system. However, the length of the PSW piping surrounded by the guard pipe is sealed, that is, the plate is welded to the PSW pipe and to the guard pipe at both ends. Thus, the external surface of this section of PSW piping is not accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The staff requests the applicant to provide appropriate information about this one-time inspection, or a comparable engineering evaluation, prior to the end of the current term.

3.1.17-1 In response to RAI 3.1.17-1, the applicant indicated that it plans to implement the provisions of an integrated surveillance program (ISP) that is documented in BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan." Should the ISP not be approved by the NRC, or if it should be modified such that Plant Hatch is not covered by the ISP, the applicant stated that it would develop an RPV surveillance program for the renewal period.

In a telephone conference on November 3, 2000, the applicant reiterated that its expectation is that the ISP, or its implementation document, will address these attributes and that, if the staff rejects BWRVIP-78, or if BWRVIP-78 is modified to the extent that the applicant cannot apply it to Plant Hatch, the applicant will develop an RPV materials surveillance program for the renewal period. As part of this commitment, if the applicant participates in the ISP or implements a plant-specific reactor vessel surveillance program, the ISP or plant-specific program should address the 10 program attributes. If the program cannot meet any program attributes, the applicant should provide a technical justification for the discrepancies.

3.1.18-1 (a) Section A.2.1 of the LRA states that, for water-based fire suppression system components, the fire protection activities prevent or mitigate loss of material by using system flushes to remove undesirable material from

the system. However, the operability of the automatic wet-pipe sprinkler systems, which are required for compliance with 10 CFR 50.48, were not discussed. In response to RAI 3.1.18-7, in which the staff notified the applicant of this omission, the applicant stated that, "unobstructed water flow from the header test valve demonstrates that sprinkler heads and piping are not clogged from corrosion product debris." The staff does not agree with this statement since (1) the arrangement of the test header at the most distant point in the sprinkler system is usually located in the fire suppression piping, which is along the path of least water resistance, and (2) the sprinkler heads are located along the smaller branch line piping and, as a result of their orientation, are typically never exposed to the flow of water during the routine testing of the test header. Since there is little or no flow in the branch lines during testing, the water in these lines remains stagnant and sediment from the raw water, which flows to the header test connection, continues to collect in the smaller branch line piping. This may result in blockage and corrosion of the branch line piping and the sprinkler heads at accelerated rates. The staff has addressed this issue in Generic Letter 89-13, "Service Water Problems Affecting Safety-Related Equipment." The staff requests that the applicant discuss the specific considerations for addressing this aging mechanism in the automatic wet-pipe sprinkler systems.

(b) With regard to the inspection frequency of fire system components, the applicant lists in Section B.2.1 of the LRA the different inspection intervals for the water-based fire protection systems, fire protection pump diesel fuel oil supply system, compressed gas based fire suppression systems, fire penetration seals, cable tray enclosures, and fire doors. In addition to the systems listed above, the applicant describes a one-time inspection called the "Sprinkler Head Inspections" that will be performed at or before the start of the extended period of operation for closed sprinkler heads within the scope of license renewal. In RAI 3.1.18-9, the staff requested that the applicant provide justification for the absence of enhanced inspection programs for the sprinkler heads, which do not have a design life that covers the period of extended operation. In response the applicant stated that, "in general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern," and that using the guidelines of the National Fire Protection Act (NFPA) Code 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection," a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads." The staff does not agree that a one-time inspection is sufficient for the sprinkler heads and recommends that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, Section 2.3.3.1, "Sprinklers." Section 2.3.3.1 states that "where sprinklers have been in place for 50 years, they shall be replaced, or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform

this sampling every 10 years after the initial field service testing. In addition, the staff has notified the nuclear industry, through recent information notices, about the potential failures associated with sprinkler heads. These information notices include IN 99-03, “Potential for Failure of the ‘Model GB’ Series Sprinkler Heads with ‘O-Ring’ Water Seals;” IN 99-28, “Recall of Star Brand Fire Protection Sprinkler Heads;” and IN 97-72, “Potential for Failure of the Omega Series Sprinkler Heads.” Problems with seals leaking and sprinkler heads failing to actuate are typically not detectable through the performance of existing visual inspections. Therefore, the staff requests that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, or provide additional justification for the applicant’s proposed inspection interval.

3.1.28-1 The staff is concerned about vibration-induced cracking in the RHR heat exchangers. The RHR heat exchanger augmented inspection and testing program description is unclear regarding its ability to manage vibration-induced cracking. Therefore, in order to ascertain whether this AMP is adequate to manage vibration-induced cracking, the staff requests that the applicant provide additional information. The requested information is summarized below.

(a) The applicant should provide information on the inspection methods, frequencies, acceptance criteria, and associated bases, which are used to detect vibration-induced cracking.

(b) The applicant should provide information regarding the leakage identified in 1996, including the analyses conducted that determined the cause of the leakage, the operational changes or component modifications that were instituted in response to the leakage, and additional programs which were developed and credited for managing vibration-induced cracking.

(c) The LRA states that measured and recordable values of the inspected or monitored parameters shall not fall below acceptable values for defined inspection locations. The staff requests that the applicant identify the inspection locations, and the inspection criteria used to determine inspection locations, and their bases.

(d) The LRA states that a sample taken from an RHRSW drain valve contained nuclides and as a result, testing was performed on one of the Unit 1 RHR heat exchangers. Dents were found at a number of tube-to-tube support connections and the dents may indicate tube vibration. The staff requests the applicant to provide the basis for its determination that the dents may have been caused by tube vibration, as opposed to localized corrosion. In addition, the staff requests that the applicant provide information regarding industry experience related to the bases and criteria of the inspections credited in the RHR heat exchanger augmented inspection and testing program.

3.2.3.1.1-1 The BWRVIP for the jet pump assembly components is described in EPRI TR-108728, "BWRVIP BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (BWRVIP-41)." The staff-approved BWRVIP-41 does not recommend an inspection of CASS jet pump assembly components because CASS components are considered not susceptible to IGSCC and the neutron fluence in the annulus region is not large enough to cause irradiation embrittlement. However, BWRVIP-41 does not contain any data to indicate the threshold for neutron embrittlement of CASS and does not identify the neutron fluence of the CASS jet pump assembly components. Because BWRVIP-41 does not provide data to support its conclusion that inspection of CASS components is not needed, the staff cannot conclude that the loss of fracture toughness resulting from irradiation embrittlement and cracking is not a plausible aging effect requiring aging management. The staff notes that irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Therefore, if the applicant can show that cracks do not occur in the CASS components, then the staff can conclude that loss of fracture toughness resulting from neutron irradiation embrittlement will not be a significant aging effect.

Industry-wide experience shows that significant cracking has not been observed in CASS jet pump assembly components. To confirm that CASS components are not susceptible to cracking, the applicant should propose an AMP (one-time inspection) for the CASS jet pump assembly components and fuel supports, which will be conducted prior to beginning the extended operating period. The BWRVIP and the NRC's Office of Regulatory Research (RES) is engaged in a joint confirmatory research program to determine the effects of high levels of neutron fluence on BWR internals, including associated age-related degradation, to confirm if CASS components are susceptible to cracking as a result of neutron embrittlement. The results of this program should be used to evaluate the need for the additional one-time inspection of the CASS jet pump assemblies and fuel supports, and to modify the inspection scope and/or frequency, as needed. The applicant should address the 10 AMP attributes in its description of the inspection, including any corrective actions to be taken (including repair and replacement) if cracking is discovered.

3.2.3.2.3-1 The staff is concerned that unanticipated high cycle thermal fatigue resulting from thermal stratification or turbulent penetration could result in cracking of small bore piping. This type of cracking is not evaluated as part of the component cyclic or transient limit program. The ASME Code Class 1 inspection requirements for small-bore piping include a surface examination, but not a volumetric examination. In order to detect cracking resulting from high cycle thermal fatigue, a volumetric examination is required. Since the proposed program does not include a volumetric examination, it may not be capable of detecting high cycle thermal fatigue cracks resulting from thermal stratification or turbulent penetration. Therefore, the applicant should supplement the existing programs with volumetric examination of the limiting locations in small-bore piping systems, excluding socket welds, which could have thermal stratification or turbulent penetration.

3.6.3.1-1 In Section 2.4.6 of the LRA, the intended function of the reactor building penetrations (T54-01) is "maintain secondary containment leakage rates within design limits." In TS Section B 3.6.4.1, under "LCO," it is states "For the secondary containment to be OPERABLE, it must have adequate leak tightness to ensure that the required vacuum ... can be established and maintained." Numerous penetrations associated with the reactor building could contribute towards violating the design limits established for secondary containment (i.e., reactor building). Thus the applicant should have an AMP to demonstrate that the overall effect of numerous degradations has not violated the leakage characteristics of the reactor building.

3.6.3.2-1 (a) In response to RAI 3.6-41 related to torus corrosion, the applicant provided a description of torus degradation found in both Plant Hatch units. However, the applicant emphasized that, in spite of the degradation, the actual shell thicknesses are well above the required minimum shell thicknesses. The applicant stated that it plans to continue to perform desludging, visual examination, and spot coating repairs periodically, based on the history of past inspection. The staff believes that operating experience at Plant Hatch and other industry operating experience related to torus corrosion indicates a need for a program to manage torus corrosion during the period of extended operation. SNC is requested to provide justification as to why this program should not be a separate program in the LRA.

(b) Table 3.3.1-3 does not provide any information regarding the aging management, including surveillance requirements, for gears, latches, and linkages of personnel hatches and penetrations. RAI 3.6-15 requested SNC to identify where fretting and lockup of hinges, locks and closure mechanisms for personnel hatches is discussed in the LRA, or provide a technical justification for not considering fretting and lockup as applicable aging effects for these components. The RAI also asked SNC to provide a description of the AMP for the personnel hatches consistent with the 10 elements in the SRP-LR in sufficient detail to allow the staff to assess the adequacy of this program to manage the applicable aging effects. The applicant responded that locks and closure mechanisms are active components, and are not subject to an AMR. Therefore, fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches and penetrations are not discussed in the LRA. However, aging management for personnel airlocks, hatches, equipment hatches and penetrations are managed by the ISI program, protective coatings program, and primary leak rate testing program as discussed in LRA Sections C.2.6.2, A.1.9, A.2.3, and A.1.14. The staff position regarding fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches and penetrations is that they are subject to an AMR and their aging effects should be managed by an AMP. SNC is requested to provide additional information to demonstrate how it will meet this staff position.

4.1.3-1 (a) Table 4.1.1-1 of the LRA identifies piping stress analyses that consider thermal fatigue cycles as a TLAA. The table does not identify the fatigue analyses of other reactor coolant pressure boundary components or the reactor vessel internals as TLAAs. Section 4.2 of the LRA does address the reactor pressure vessel. In RAI 4.1-2 the staff asked the applicant to identify other components of the reactor coolant pressure boundary that have fatigue analyses. The staff also asked the applicant to describe the TLAAs performed to address fatigue for the reactor coolant pressure boundary components, except for the reactor vessel, that were not included in Table 4.1.1-1, and to describe the TLAA performed for the reactor vessel internals. The applicant was also asked to indicate how these TLAAs meet the requirements of 10 CFR 54.21(c). In response, the applicant stated that the criteria of BWRVIP-74 was used to determine which fatigue analyses were significant enough to be a TLAA. As indicated in the RAI, the applicant discussed the fatigue analysis of the reactor vessel internals in the FSAR. The staff requests that the applicant explain how the fatigue analysis of the vessel internals was found to be acceptable for the 60-year period. The staff also requests that the applicant identify any other components of the reactor coolant pressure boundary that had fatigue analyses and explain how these analyses were found acceptable for the 60-year period.

(b) Section 4.2.2 of the LRA contains a discussion of the Plant Hatch licensing basis pipe break criteria. Part of the Plant Hatch pipe break criteria involves postulation of pipe breaks at locations where the calculated fatigue usage exceeds a specified value. Although the applicant identified the fatigue cumulative usage factor (CUF) calculation as a TLAA, the applicant concluded that the pipe break criteria was only a screening criteria and not a TLAA (the specific design criterion pertaining to the fatigue evaluation of RCS components involves calculating a quantity called the cumulative usage factor. 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). The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In RAI 4.2-1 the staff asked the applicant to provide a description of a TLAA for the pipe break criteria at Plant Hatch and to describe how the TLAA meets the requirements of 10 CFR 54.21(c). In response, the applicant stated that it views the pipe break criteria to be a selection criteria that establishes a bounding set of locations for line break consideration. Although the staff agrees with the applicant’s statement, the staff still considers pipe break postulations a TLAA because the fatigue calculation is a TLAA. Additionally, the NRC previously identified high-energy line break postulation based on fatigue cumulative usage factor as a TLAA in

accordance with 10 CFR 54.3 (60 FR 22480, May 8, 1995). Therefore, the staff requests that the applicant include pipe break postulations based on fatigue usage factor as a TLAA.

4.2.3-1 By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two EPRI technical reports dealing with the fatigue issue. EPRI Reports TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," and TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations" were 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 reports. The staff technical concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998. NEI responded to the staff concerns in a letter dated April 8, 1999. The staff submitted its assessment of the response in an August 6, 1999, letter to NEI. As indicated in the staff letter, the NEI response did not resolve all staff technical concerns regarding the EPRI reports.

The applicant indicates that EPRI license renewal fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects for Plant Hatch. As discussed above, the staff does not agree with the contention that the EPRI fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects. Although the August 6, 1999, letter identified staff concerns regarding the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff has additional concerns regarding the applicability of the EPRI BWR studies to Plant Hatch. EPRI Report TR-107943, “Environmental Fatigue Evaluations of Representative BWR Components,” addressed a BWR-6 plant and EPRI Report TR-110356, “Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant,” used plant transient data from a newer vintage BWR-4 plant. In RAI 4.2-2, the staff requested that the applicant provide additional information regarding the use of the EPRI license renewal fatigue studies to resolve the environmental fatigue issue at Plant Hatch.

In response to the RAI, the applicant discussed its assessment of the impact the environmental correction factors for carbon and low-alloy steels contained in NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” and those for austenitic stainless steels contained in NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels” on the results of the EPRI

studies. As a result of its assessment, the applicant concluded that the correlations have been adequately accounted for via the conservatism of the design basis transients.

The applicant indicated that EPRI Report TR-110356 contained studies that are directly applicable to Plant Hatch because the study involved a BWR-4 that is identical to the Plant Hatch design. The only components evaluated in TR-110356 are the feedwater nozzle and the control rod drive penetration locations. However, the applicant indicated that both Plant Hatch units employ hydrogen water chemistry, whereas the plant in the EPRI study did not consider hydrogen water chemistry. Hydrogen water chemistry affects the level of dissolved oxygen in the primary system. Dissolved oxygen is an important factor in the environmental fatigue effects. The applicant stated that this issue was adequately addressed by its evaluation of the feedwater nozzle contained in EPRI Report TR-105759. It is not clear to the staff how the issue of hydrogen water chemistry was addressed in EPRI Report TR-105759. The applicant's response has not resolved the staff concerns regarding the environmental fatigue issue at Plant Hatch.

The staff requested that the applicant provide an assessment of the six locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999, 'Interim Fatigue Curves to Selected Nuclear Power Plant Components'," March 1995, for an older vintage BWR (BWR-4) considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Plant Hatch Units 1 and 2. The applicant indicated that these locations are monitored by the CCTLP and that the environmental factors have been adequately accounted for by the conservatism in the design basis transient definitions. On the basis of the discussion above, the staff does not agree with the applicant that environmental fatigue concerns regarding the six locations identified in NUREG/CR-6260 have been adequately addressed at Plant Hatch. The applicant is therefore requested to assess these six locations, considering applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704, as applicable.

1.5 Summary of Confirmatory Items

As a result of it's review of the LRA, including the additional information and clarifications that were submitted, the staff did not identify any confirmatory items.

2 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

This section of the SER describes the staff's review of the methodology used by Southern Nuclear Operating Company, Inc. (SNC) to implement the scoping and screening requirements of 10 CFR Part 54 (the Rule), as well as the staff's evaluation of SNCs scoping and screening results.

By letter dated February 29, 2000, SNC submitted its request and application for renewal of the operating licenses for the Edwin I. Hatch Nuclear Plant, Units 1 and 2. As an aid to the NRC staff during the review, SNC provided evaluation boundary drawings that identify the functional boundaries for systems and components within the scope of license renewal. These evaluation boundary drawings are not part of the license renewal application.

On July 14 and July 28, 2000, the staff issued requests for additional information (RAIs) regarding the applicants methodology for identifying structures, systems, and components (SSCs) at Plant Hatch that are within the scope of license renewal and subject to an aging management review (AMR) and the results of the applicant's scoping and screening process. On August 29 and October 10, 2000, the applicant provided responses to the RAIs.

2.1 Scoping and Screening Methodology

2.1.1 Introduction

In Section 2.1, "Scoping and Screening Methodology," of the Plant Hatch license renewal application (LRA), the applicant described the scoping and screening methodology used to identify structures, systems, and components (SSCs) at Plant Hatch that are within the scope of license renewal, and structures and components (SCs) that are subject to an AMR. The staff reviewed the applicant's scoping and screening methodology to determine if it meets the scoping requirements set forth in 10 CFR 54.4(a) and the screening requirements set forth in 10 CFR 54.21.

10 CFR 54.21, "Contents of Application — Technical Information," requires, in part, that each application for license renewal contain an integrated plant assessment (IPA) that identifies and lists those SSCs that satisfy the criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) that are subject to an AMR. 10 CFR 54.4, "Scope," defines the criteria for including SSCs within the scope of the Rule.

In developing the scoping and screening methodology for the Plant Hatch LRA, the applicant considered the requirements of the Rule, the Statements of Consideration (SOCs, 60 FR 22401, May 8, 1995) for the Rule, and the guidance provided by the Nuclear Energy Institute (NEI), "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," Revision 0 (NEI 95-10). In addition, SNC also considered the NRC staff's correspondence with other applicants and with the NEI in the development of this methodology. The applicant stated that the methodology was also developed with the knowledge that some provisions of the Rule may be satisfied by implementing 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (the Maintenance Rule) at Plant Hatch.

2.1.2 Summary of Technical Information in the Application

Section 2.1 of the Plant Hatch LRA, describes the process that SNC used to implement the scoping requirements of the Rule as specified in 10 CFR 54.21(a)(2). As used in the Plant Hatch application methodology, scoping is the process of identifying systems and structures that meet the scoping criteria of 10 CFR 54.4(a)(1) - (3), including the identification of intended functions as defined by 10 CFR 54.4(b) — those functions that are related to meeting one or more of the scoping criteria of 10 CFR 54.4(a)(1) - (3). The Plant Hatch scoping criteria, as applied to plant SSCs are:

- reactor coolant pressure boundary integrity (10 CFR 54.4(a)(1)(i))
- safe reactor shutdown and maintenance (10 CFR 54.4(a)(1)(ii))
- accident consequence prevention or mitigation (10 CFR 54.4(a)(1)(iii))
- non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions associated with the items above (10 CFR 54.4(a)(2))
- compliance with fire protection regulations (10 CFR 50.48) (10 CFR 54.4(a)(3))
- compliance with environmental qualification regulations for electrical equipment(10 CFR 50.49) (10 CFR 54.4(a)(3))
- compliance with anticipated transient without scram (ATWS) regulations (10 CFR 50.62) (10 CFR 54.4(a)(3))
- compliance with station blackout (SBO) regulations (10 CFR 50.63) (10 CFR 54.4(a)(3))

An additional regulation, 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154, “Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors,” January 1987 is not required for boiling water reactor plants.

The identification and listing of structures and components (SCs) that are subject to an AMR is called “screening” in the Plant Hatch application methodology, as discussed in Section 2.1.3 of the LRA for civil/mechanical disciplines, and in Section 2.1.4 of the LRA for the electrical discipline.

2.1.2.1 Technical Information for Identifying Systems, Structures, and Components Within the Scope of License Renewal

As provided in 10 CFR 54.4(a)(1), design-basis events for license renewal are applied as defined in 10 CFR 50.49(b)(1), consistent with the current licensing basis (CLB).
10 CFR 54.4(b) provides that the intended functions that these SSCs must be shown to fulfill in 10 CFR 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in 10 CFR 54.4(b), paragraphs (a)(1)-(3).

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

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

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

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

The scoping requirements of the license renewal rule and the maintenance rule overlap. Because of the similarities in the rules, the Plant Hatch Maintenance Rule Scoping Manual was one of the information sources used to establish an initial listing of plant system and structure functions.

The final list of functions evaluated for license renewal encompasses all plant systems and structures, except as described in Section 2.1.2.3 of the LRA. The functions did not necessarily follow traditional system boundaries, in that the functions included structures and components, irrespective of traditional system nomenclature, that perform or support the identified function. To arrive at the component level, SNC chose to scope at a function level and screen at the component level. SNC elected to use the term "component function" when referring to the specific structure, component, or component group functions needed to support an intended function. Systems and structures that only provide emergency preparedness or physical protection functions were not evaluated in the scoping process.

Safety-Related Systems and Structures

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

- Is the function of the system or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the integrity of the reactor coolant pressure boundary?

- Is the function of the system or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition?

- Is the function of the system or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 100.11?

To answer these questions, the applicant used engineering and licensing documents. The ELI and the SED are engineering documents that provide system-related design information. The FSARs, the Maintenance Rule Scoping Manual, and the SED provide function-related information. The FSARs and applicable references identify the basis for design-basis events at Plant Hatch. If the answer to one or more of the three questions was "YES," the corresponding system or structure function was determined to be within the scope of the Rule and was designated as an intended function as identified by 10 CFR 54.4(b).

In certain cases, the applicant has conservatively chosen to designate some systems as safety-related, even though their functions may not meet any of the scoping criteria of 10 CFR 54.4(a)(1). System functions brought into scope by 10 CFR 54.4(a)(1) were also reviewed to determine whether they were also in scope based on the requirements of 10 CFR 54.4(a)(2) or 10 CFR 54.4(a)(3). In addition, functions may include, in a few cases, both safety-related and non-safety-related components. In those cases, a function would be identified as meeting the scoping criteria of 10 CFR 54.4(a)(1), as well as the requirement for 10 CFR 54.4(a)(2), as described below.

Non-safety-Related Systems and Structures Whose Failure Could Prevent Safety-Related Systems and Structures from Accomplishing Their Functions

10 CFR 54.4(a)(2) provides that "all nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii)" of 10 CFR 54.4 are within the scope of the Rule. Few system and structure functions at Plant Hatch satisfy this criterion because systems and structures supporting safety-related systems and structures were typically designed as safety-related. Each system and structure function in the plant's listing of scoping results was reviewed with respect to this requirement by addressing the following question:

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

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

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

If a function was used to mitigate one or more of the issues or events, the answer to the above question was "YES," the corresponding system or structure function was brought in scope, and

the function was identified as an intended function per 10 CFR 54.4(b). In making determinations associated with this question, SNC also relied on the consideration of actual plant-specific experience, industry-wide operating experience, and existing plant-specific engineering evaluations that were originally addressed by the controlled Maintenance Rule Scoping Manual determinations. Hypothetical failures that result from postulated system functional interdependencies that are not part of the Plant Hatch safety analyses or effects evaluations and that have not been observed at Plant Hatch were not considered.

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

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

- 10 CFR 50.48, "Fire Protection"
- 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"
- 10 CFR 50.62, "Requirements for Reduction of Risk from Anticipated Transients Without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants"
- 10 CFR 50.63, "Loss of All Alternating Current Power"

An additional regulation, 10 CFR 50.61, "Fracture Toughness Requirements for Protection Against Pressurized Thermal Shock Events," does not apply to Plant Hatch, because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154 is not required for boiling water reactor plants.

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

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

- Is the function of the system or structure relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulation for SBO (10 CFR 50.63)?

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

During the review of the EQML, NRC SERs, and docketed correspondence, SNC confirmed that any credited functions and the systems and structures that specifically contribute to accomplishing the functions were included in the list of system or structure functions. For the remaining questions, regarding the fire protection, ATWS, and station blackout regulations, if the answer to any of the questions was "YES," then each corresponding system or structure function was brought into scope and was identified as an intended function per 10 CFR 54.4(b). The NRC SERs and associated docketed correspondence were used to answer these questions.

2.1.2.2 Technical Information for the Structures and Components Subject to an Aging Management Review

<u>Civil/Mechanical Component Screening</u>

The license renewal rule requires a review of plant SSCs to determine if the effects of aging will be adequately managed for certain SCs in the period of extended operation. The process described in LRA Section 2.1.2 was used to identify the intended functions, that is, those SSC functions that are within the scope of the Rule. 10 CFR 54.21(a) requires that an IPA process be applied to SSCs determined to be in scope per 10 CFR 54.4. The IPA process employed by SNC required an initial review of those functions within the scope of the Rule, as determined by the process described in LRA Section 2.1.2, to define intended function evaluation boundaries. The intended function evaluation boundaries were then used to assist in the identification of the SCs that are subject to an AMR.

10 CFR 54.21(a)(1) requires applicants to identify and list the SCs subject to an AMR. LRA Section 2.1.3 defines a "screening" process whereby SNC identified and listed the SCs that met the criteria of 10 CFR 54.21(a)(1)(i) and (ii). Use of the term "passive" within this application is intended to be identical to criterion (i). That is, SCs that perform an intended function without moving parts or without a change in configuration or properties are characterized as "passive." Likewise, use of the term "long-lived" is intended to be identical to criterion (ii). That is, structures and components that are not subject to replacement based on a qualified life or specified time period are characterized as "long-lived."

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

1. Evaluation boundaries were established for each intended function.

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

Intended Function Evaluation Boundaries

This step of the screening process defined the evaluation boundary for the system and structure functions determined to be within the scope of the Rule by the process described in LRA Section 2.1.2. These functions are the intended functions per the definition in the Rule. Defining the evaluation boundary focuses the screening process on the portions of systems and structures that contribute to the performance of one or more intended functions. Evaluation boundaries were established such that multiple, in-scope functions are included in one evaluation boundary description to the extent practical.

Evaluation boundaries were produced using controlled procedures to ensure a consistent approach to preparation and documentation. Evaluation boundaries, as used in this methodology, were not required to match other boundaries that are defined in existing documents such as the FSARs or plant piping and instrumentation diagrams. Defining evaluation boundaries for license renewal does not require the plant to change or redefine other existing boundaries such as pipe class design boundaries or inservice inspection and testing boundaries. In addition, where a functional boundary was defined in the CLB for an in-scope function, the CLB-defined boundary was used. SNC chose to conservatively designate certain components as “in scope” more broadly than the Rule might otherwise require.

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

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

In the process of defining evaluation boundaries, emphasis was placed on ensuring that all interfaces were adequately considered. As necessary, other references, prepared lists, and written descriptions were used to supplement or further clarify the boundary designations on the marked-up drawings. The final set of illustrated mechanical and electrical drawings,

references, and written descriptions formed the "boundary package" for an intended function, and was documented by controlled procedures. In order to maintain a consistent approach to screening, general and specific discipline interface guides were established and used to assist in designating the intended function evaluation boundaries and interfaces.

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

Component Types, Component Groups, and Component Functions

LRA Table 2.1-1 lists component types that are in scope for license renewal at Plant Hatch. This table is based on a table that originated as Appendix B of NEI 95-10, Revision 0 (Ref. 2.1.5.3). During the process of screening structures and components at Plant Hatch, additional component types were identified and are included in LRA Table 2.1-1.

The list in LRA Table 2.1-1 represents the plant-wide list of in-scope structures and components, by component type. The tables in LRA Sections 2.3 through 2.5 present the screening results arranged by plant system or structure member. Each component type listed in the tables in LRA Sections 2.3 through 2.5 is a passive component as determined in LRA Table 2.1-1. Although not required by the Rule, in order to more efficiently screen SCs, component types within each intended function evaluation boundary were grouped to the maximum extent practicable. In creating these component groups, only components of the same type were grouped together. That is, a component group of valves did not include pipe. In addition, only component types within each intended function evaluation boundary that were fabricated of similar materials, and which were subjected to similar environments were grouped. Structural or mechanical components included in each component group were identified and documented by one or a combination of the following methods:

- by establishing a list of the MPL numbers
- by listing the reference drawings
- by describing the component or system

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

Component function(s) for component types subject to an AMR were established on the basis of how the structure or component functions to support maintaining one or more intended functions consistent with the CLB, without reliance on redundancy or probabilistic considerations. LRA Table 2.1-2 provides the list of component functions used in the structure and component screening at Plant Hatch.

Passive Structures, Components, and Component Groups

The SNC process defined evaluation boundaries for intended functions associated with structures and screened the boundaries to identify the passive and long-lived elements of the structures. Although intended function evaluation boundary drawings were not produced for the structures, the structural components screening included the active/passive and long/short-lived determinations as a matter of completeness and to facilitate the aging management reviews.

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

The detrimental effects of aging are assumed to be continuous and incremental. Thus, the detrimental effects of aging may increase as service life is extended, assuming no replacement of components. One way of effectively managing these effects is to replace selected structures and components on a specified time interval, based upon a qualified life of the structure or component. In this step of the screening process, the passive structures and components were reviewed to determine if they are subject to replacement based upon a specified time or qualified component life. Structures and components that are not subject to such replacement were classified as "long-lived." In the methodology employed by SNC, a replacement life must be less than 40 years for the structure or component to be considered "short-lived." Structures and components with replacement lives of 40 years or greater were considered "long-lived." Structures and components subject to replacement based on qualified life were identified as not being subject to an AMR.

Identification of Electrical Components Subject to an Aging Management Review

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

1. Develop a comprehensive list of all electrical component types installed in the plant without regard for system function or license renewal in-scope status.

2. Determine the basic function that each component type performs.

3. Determine which component types perform their function(s) without moving parts or a change in configuration or properties. This results in the list of electrical component types that are subject to an AMR for license renewal.

4. Apply the scoping criteria of 10 CFR 54.4(a)(1) through (3) to the list of component types that meet the screening criteria to determine if the list of electrical component types requiring an AMR can be further reduced.

In order to screen electrical component types to determine those which require an AMR, a complete list of all electrical component types installed in the plant was required. This list was compiled using the lists of components found in 10 CFR 54.21(a)(1)(i) and NEI 95-10,

Appendix B, as the starting point. The resulting list of components was evaluated by plant engineering personnel and system experts who used their knowledge of plant systems and drawings to ensure that the list was complete and contained all electrical component types in use at Plant Hatch. Some component types with similar functions were grouped together for simplicity. The in-scope electrical component types installed at Plant Hatch are included in LRA Table 2.1-1. The list of electrical component types that are subject to an AMR appears in LRA Table 2.5.15-1.

Application of 10 CFR 54.21 Screening Criteria to Electrical Component Types

Having compiled the electrical component type list, 10 CFR 54.21 criteria were applied to determine which component types are subject to an AMR. The screening criteria of 10 CFR 54.21(a)(1)(i) and (ii) were applied to the comprehensive list of electrical component types to accomplish this step. Components are subject to an AMR if they meet both of the following screening criteria:

- 10 CFR 54.21(a)(1)(i) – The component performs an intended function as described in 54.4 without moving parts or without a change in configuration or properties.

- 10 CFR 54.21(a)(1)(ii) – The component is not subject to replacement based on a qualified life or a specified time period.

An active/passive determination in accordance with 10 CFR 54.21(a)(1)(i) was documented for each type of electrical component installed at Plant Hatch. This determination is presented in LRA Table 2.1-1.

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

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

Application of 10 CFR 54.4 Scoping Criteria to Electrical Component Types

Scoping was performed as described in LRA Section 2.1. The set of passive, long-lived component types derived from the process described in LRA Section 2.1.4.1, steps 1 through 3,

was then evaluated against the scoping criteria stated in step 4. This step was performed to further define the set of electrical component types that are subject to an AMR. The set of electrical component types remaining after completion of steps 1 through 4 of the screening process are included in the list in LRA Table 2.1-1 as component types that are subject to an AMR.

2.1.3 Staff Evaluation

The staff reviewed the methodology used by the applicant to identify SSCs at Plant Hatch that meet the scoping criteria of 10 CFR 54.4, and to identify SCs that meet the screening criteria of 10 CFR 54.21(a)(1) and (2). The staff used Standard Review Plan for License Renewal (SRP-LR), Section 2.1, “Scoping and Screening Methodology,” to perform the scoping and screening review.

2.1.3.1 Evaluation of the Methodology for Identifying Systems, Structures, and Components That are Within the Scope of License Renewal

The staff evaluated the applicant’s scoping methodology, as described in the LRA, to determine whether the methodology met the requirements of 10 CFR 54.4. As part of the evaluation process, the staff conducted an audit from June 12 through June 15, 2000, to determine whether the scoping methodology described by SNC in its LRA was implemented consistent with the requirements of 10 CFR Part 54 and the Plant Hatch LRA. The audit took place at the SNC offices in Birmingham, Alabama. The audit consisted of a review of the scoping methodology implementing procedures and supporting information used by SNC to identify the Plant Hatch SSCs within the scope of the license renewal rule. The audit also examined a selected sample of products or results obtained by SNC through its use of the scoping and screening methodology procedures.

The staff followed guidance provided in Section 2.1.3.1 of the SRP-LR to evaluate the scoping methodology described in Section 2.1.2.1 of this SER. The staff reviewed the applicant’s process used to identify and classify SSCs as safety-related and non-safety-related, and to identify and classify SSCs that meet the definition of “regulated events” (i.e., those SSCs that are relied on in safety analyses or plant evaluations to perform functions that demonstrate compliance with the requirements of the fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63) regulations).
Section 2.1.2.4 of the LRA described the applicant’s process to identify safety-related SSCs that are within the scope of the Rule. Section 2.1.2.5 of the LRA described the applicant’s process to identify non-safety-related SSCs within the scope of the Rule. Section 2.1.2.6 or the LRA described the applicant’s process to identify those SSCs that meet the requirements of the regulations associated with regulated events. In Section 2.1.2.6 of the LRA, the applicant noted that 10 CFR 50.61 does not apply to Plant Hatch because, as specified in the regulation, an evaluation in accordance with Regulatory Guide 1.154, is not required for BWRs. The staff agrees with this determination.

On the basis of its review of the scoping methodology described in the LRA and summarized in Section 2.1.2.1 of this SER, the staff concludes that, pending resolution of the Open Item 2.1.3.1-1, identified below, the methodology, as described in the LRA, is consistent with

the requirements of the Rule, and that the scoping methodology will identify SSCs that meet the scoping criteria of 10 CFR 54.4. A summary of the scoping portion of the audit is described below.

During the audit at the SNC offices, the staff reviewed a variety of scoping methodology implementation procedures, including License Renewal Service Procedure (LRS) 1-1, “Revisions and Distribution of the License Renewal Services Procedures Manual,” LRS 1-2, “Scoping Procedure,” LRS 1-3, “Plant Hatch Scoping Template,” LRS 1-4, “Boundary Procedure,” and LRS 1-9, “LRS Database Control Procedure.” The team also held discussions with SNC technical personnel, examined licensing basis documents, and reviewed samples of system functional boundary description packages to better understand the scoping and screening process.

Plant Hatch License Renewal Scoping and Screening Procedures Review Results

The applicant employed implementation procedures LRS 1-2 and LRS 1-3 to perform the scoping process. LRS 1-3 provided overall license renewal scoping evaluation guidance. The applicant began its process for identifying SSCs that are within the scope of the Rule by relying on 131 systems and 256 functions that were previously identified in the Plant Hatch maintenance rule scoping manual. Additional functions were also identified through a review of the CLB, which includes the Plant Hatch FSARs, operating license/technical specifications, docketed correspondence, SEDs, maintenance rule scoping database, and the ELI, and through a review of NRC safety evaluations reports to identify additional functions associated with regulated events as defined in 10 CFR 54.4(a)(3).

In the subsequent phase of the review, the applicant evaluated all Plant Hatch systems and structures on a function-by-function basis against specific license renewal criteria, including (a) safety-related — reactor coolant pressure boundary (§54.4(a)(1)(i)); (b) safety-related — safe shutdown (§54.4(a)(1)(ii)); (c) safety-related — prevent or mitigate the consequences of accidents §54.4(a)(1)(iii)); (d) non-safety-related [functions] that affect safety-related functions (§54.4(a)(2)); and (e) relied on to demonstrate compliance with 10 CFR 50.48 (fire protection), 10 CFR 50.49 (environmental qualification), 10 CFR 50.62 (anticipated transient without scram), or 10 CFR 50.63 (station blackout). Following completion of this evaluation, 137 systems and 280 functions were identified and catalogued.

SNC used LRS 1-4 to define the evaluation boundaries for electrical, mechanical, and civil system and structure functions that are determined to be within the scope of the Rule. This procedure provided the guidance necessary to generate system boundary diagrams including interfaces between mechanical and electrical boundaries. Boundary description packages (BDPs) were developed containing written descriptions of the evaluation boundary illustrated by the boundary diagrams and identified all in-scope functions included in the evaluation boundary. Review and sign-off authority for BDPs was also identified.

SNC used LRS 1-9 in conjunction with TS 1-9, “Quality Assurance Records,” to govern the documentation and quality assurance of the records of the scoping and screening process.

Based on its review of these procedures and from discussions held with Plant Hatch personnel, the audit team identified certain discrepancies between the scoping and screening process

described in the procedures and the actual process that was followed. Specifically, the procedures did not provide a clear description and account for all essential activities in the scoping and screening process, nor did they clearly portray the sequence in which these activities were actually accomplished.

To gain a better understanding of the actual scoping and screening methodology used by the applicant, the staff selected three Plant Hatch systems (standby liquid control, high-pressure coolant injection, and service water) and performed a “walk-through” of the process described in the methodology procedures. Plant Hatch personnel assisted the audit team as it performed the walk-through.

Based on the results of the walk-through, and the staff’s assessment of the actual implementation process and its oversight as applied by the applicant, the audit team determined that the procedures reviewed, in combination with the review of a sample of scoping and screening products, and with the benefit of insights provided by Plant Hatch personnel who were directly involved with the development of such products, provided adequate evidence that the scoping and screening process was conducted in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21. However, the team also concluded that the applicant needed to update these procedures to satisfy the requirements of 10 CFR 54.37, “Additional Records and Recordkeeping Requirements,” to reflect the actual scoping and screening process upon which the applicant relied and will rely to address future changes in the CLB.

Therefore, the applicant was requested to confirm, through a July 14, 2000, request for additional information (RAI 2.1-1), that the Plant Hatch license renewal scoping and screening procedures would be updated to clearly reflect the actual process used for both the current application as well as future updates to the application based on changes to the CLB, and to specify the time-frame during which this update would be accomplished.

In its response to the staff’s RAI, dated August 29, 2000, SNC stated its commitment to expand the existing procedures from a goal-oriented approach to a more detailed presentation of the steps employed so that the scoping and screening processes were more clearly identified in the procedure steps. SNC stated that these revised procedures would be used for the LRA update required by 10 CFR 54.21(b), and they would be in place prior to performing the first required LRA update. Accordingly, SNC planned to have the revised procedures in place by September 11, 2000.

During the scoping and screening inspection conducted on September 11 through 15, 2000, the inspectors reviewed the revised procedures, and confirmed that they had been revised to adequately reflect the scoping and screening methodology. The staff concluded that the applicant’s scoping and screening implementation procedures met the recordkeeping requirements of 10 CFR 54.37. On this basis, the issue identified in RAI 2.1-1 is resolved.

Review of 10 CFR 50.12 Plant Hatch Exemptions

The audit team reviewed the history of 10 CFR 50.12 exemptions at Plant Hatch to identify any potential SSCs that are within the scope of license renewal, but were not identified by the applicant’s scoping methodology. The staff reviewed 32 exemptions and their associated correspondence. Of these, the staff noted that 1 exemption was not granted by the staff, 8

were no longer in effect, 22 were not age-related or time-limiting, and the remaining exemption was in effect, age-related, time-limiting, and the affected system had been included within the scope of license renewal.

Review of Design-Basis Events

Because the Plant Hatch scoping activities were primarily performed on the basis of intended function, rather than on design-basis events, the audit team reviewed the design-basis events identified in a study documented in a recent amendment to the Plant Hatch Unit 2 FSAR. Plant Hatch Unit 2 FSAR, Supplement 15C, “Nuclear Safety Operational Analysis” (NSOA), is a comprehensive summary of all design basis events, including anticipated operational occurrences, applicable to both Plant Hatch units and represents the culmination of an extensive design-basis reconstitution effort at Plant Hatch. However, the Plant Hatch license renewal scoping and screening process was completed before efforts associated with Supplement 15C to the Plant Hatch Unit 2 FSAR were finalized.

Accordingly, the applicant was requested to provide information on actions it intended to undertake to ensure that the information relied on to generate the scoping and screening results in accordance with the methodology described in the Plant Hatch LRA is consistent with, and supported by, the design- and licensing-basis information in Supplement 15C to the Plant Hatch Unit 2 FSAR. This was identified as RAI 2.1-2.

In its response to the staff’s RAI, dated August 29, 2000, SNC stated that it had informally reviewed the draft NSOA during preparation of the LRA. Although the document was not used as an "official" source of information due to its draft status, SNC clarified that since the document has been incorporated into the CLB by virtue of its inclusion in the Plant Hatch Unit 2 FSAR, Supplement 15C, SNC would evaluate the NSOA using the scoping criteria of 10 CFR 54.4 to determine whether additional SSCs should be brought in scope based on the NSOA event sequences. The results of this evaluation will be documented internally, and any additions to the Plant Hatch LRA will be provided to the NRC in the scheduled annual update.

In its annual update of the Plant Hatch LRA, dated December 15, 2000, SNC described the methodology used to complete the NSOA review to ensure that the information relied on to generate the scoping and screening results was consistent with the information in the NSOA. According to SNC, the NSOA identifies the active system-level requirements that ensure that the Plant Hatch safety analysis is valid for all limiting operational conditions. However, while the Plant Hatch safety analysis is essentially consequences-oriented, the NSOA is event/system-oriented.

The methodology used in completing the NSOA review focused on the consideration of each of the NSOA events and the system functions required to accomplish the required action (e.g., reactor shutdown, core cooling, etc.). In performing this review, each event diagram and corresponding evaluation was compared to the LRA and supporting documentation to determine if, in each case, the required action is achieved by system functions within the scope of the license renewal. In addition, FSAR Supplement 15C supporting documentation was also reviewed to ensure that the information was addressed by the LRA. The support systems/functions for each function (e.g., DC and auxiliary AC power for core spray) were also evaluated by SNC.

As a result of this review, Plant Hatch Function C51-02, Rod Block Monitor, previously identified in the LRA as not within the scope of license renewal has been brought in scope. No new component types were added to the list of plant-wide electrical components that are subject to an AMR as a result of this scoping change.

Based on the information provided by SNC in its Plant Hatch LRA annual update, the staff has determined that the actions taken by SNC provide reasonable assurance that the information relied on to generate the scoping and screening results in accordance with the methodology described in the Plant Hatch LRA is consistent with, and supported by, the design- and licensing-basis information in Supplement 15C to the Plant Hatch Unit 2 FSAR. On this basis, therefore, the concern identified in RAI 2.1-2 is resolved.

Review of Commission Orders

The staff reviewed 28 Commission Orders from 1974 through 1998. All of the SSCs referred to in each of the 28 Commission Orders were identified and compared to the list of SSCs included within the scope of license renewal. All SSCs identified in the 28 Commission Orders were included within the scope of license renewal.

Seismic II Over I

The scoping requirements of 10 CFR 54.4(a)(2) include all non-safety-related SSCs whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs 10 CFR 54.4 (a)(1)(i), (ii), or (iii). In Section 2.1.2.5 of the LRA, the applicant stated that the few cases where non-safety-related components could impact safety-related functions were included in the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(2). In the staff's requests for additional information (RAIs) 3.4-11 and 3.6-51, dated July 28, 2000, the staff requested that the applicant clarify whether the scope of the auxiliary systems discussed in Section 3.2.4 of the LRA includes any spatially-related components and piping segments within the category of "Seismic II Over I" (a non-seismic Category SSC whose failure could cause loss of safety function of a seismic Category I SSC). In addition, the staff requested that the applicant clarify how the aging management programs for the non-safety-related systems and components have been addressed. Specifically, the staff requested the applicant to state whether the same aging management programs discussed in Table 3.2.4 of the LRA also apply to the seismic II over I piping components. The applicant responded to these RAIs in its letter dated October 10, 2000. The applicant stated that the pipe supports for the seismic II over I piping systems are within the scope of license renewal and thus the supports for the seismic II over I piping systems are included within the scope of the aging management programs identified in the LRA. However, the applicant also stated that no aging management programs are applied to out-of-scope piping segments with seismic II over I piping supports. In a telephone conversation on October 24, 2000, the applicant further clarified this point. The applicant stated that within the context of the Plant Hatch licensing basis, non-safety-related piping systems are postulated to fall in a seismic event if not seismically supported. Thus, for the protection of safety-related piping, some non-safety-related piping is seismically supported. Those seismic supports are within the scope of license renewal, but the applicant does not consider the seismic II over I piping segments to be within the scope of license renewal. The staff does not agree with the applicant's scoping criteria for seismic II over I piping systems. The staff's position is that the seismic II over I piping whose failure could

prevent safety-related systems and structures from accomplishing their intended functions should be within the scope of license renewal. The staff considers the seismic II over I piping segments to be within the scope of license renewal. This issue is identified as Open Item 2.1.3.1-1.

Impact of Rule Amendments

In Section 2.1.2.4 of the LRA, the applicant states that 10 CFR 54.4(a)(1)(i), (ii), and (iii), provide the scoping criteria for determining the functions of safety-related systems and structures that are within the scope of the Rule. The applicant adds that each system and structure function in the plant listing of scoping results (Table 2.2-1) was determined with respect to these requirements by addressing the following questions:

1. Is the function of the system or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the integrity of the reactor coolant pressure boundary?

2. Is the function of the systm or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the capability to shut down the reactor and maintain it in a safe shutdown condition?

3. Is the function of the system or structure identified as safety-related because it is relied upon during and following design-basis events to ensure the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in 10 CFR 100.11?

The staff notes, however, that the current language in 10 CFR 54.4 states, in part, that plant SSCs within the scope of license renewal are (1) safety-related SSCs which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49(b)(1)) to maintain the following functions:

- integrity of the reactor coolant pressure boundary

- capability to shut down the reactor and maintain it in a safe shutdown condition

- capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to the guidelines in §50.34(a)(1), §50.67(b)(2), or §100.11 of this chapter, as applicable

By letter dated January 5, 2001, the staff requested the applicant to confirm that the information in the LRA met the revised requirements in 10 CFR Part 54.

By letter dated January 31, 2001, the applicant confirmed that the LRA met the revised requirements of 10 CFR Part 54. Specifically, the applicant stated that the provisions of 10 CFR 50.34(a)(1) do not impact the Plant Hatch LRA, and that SNC has not incorporated the alternate source term provisions of 10 CFR 50.67(b)(2) into the Plant Hatch design or licensing basis. Thus, there is no effect on Plant Hatch license renewal scoping.

The staff reviewed the provisions of 10 CFR 50.34(a)(1) and 10 CFR 100.11 and concluded that the provisions of 10 CFR 100.11 are bounding with respect to the Plant Hatch LRA. In addition, the provisions of 10 CFR 50.67(b)(2) are not applicable to the Plant Hatch CLB. Therefore, the staff concludes that the Plant Hatch LRA meets the revised requirements of 10 CFR Part 54.

2.1.3.2 Evaluation of the Methodology for Identifying Structures and Components Subject to an Aging Management Review

The staff evaluated the applicant's screening methodology, as described in the LRA, to determine whether the methodology met the requirements of 10 CFR 54.21(a)(1). The staff followed guidance provided in Section 2.1.3.2 of the SRP-LR to evaluate the screening methodology provided in Sections 2.1.3 and 2.1.4 of the LRA, and described in Section 2.1.2.2 of this SER. The staff reviewed the applicant's process used to identify and classify SCs as passive (those that perform their intended functions without moving parts or a change in configuration or properties) and long-lived (those that are not subject to periodic replacement based on qualified life or specified time period). Section 2.1.3 of the LRA describes the applicant's process to identify civil/structural SCs that are subject to an AMR. Section 2.1.4 of the LRA describes the applicant's process to identify electrical components that are subject to an AMR.

As part of the evaluation process, the staff conducted an audit from June 12 through June 15, 2000, to determine whether the screening methodology described by SNC in its LRA was implemented consistent with the requirements of 10 CFR Part 54 and the Plant Hatch LRA. The audit took place at the SNC offices in Birmingham, Alabama.

On the basis of its review of the screening methodology described in the LRA and summarized in Section 2.1.2.2 above, the staff concludes that the methodology, as described in the LRA, is consistent with the requirements of the Rule, and that the screening methodology will identify SCs that meet the screening criteria of 10 CFR 54.21(a)(1). The screening portion of the audit is described below.

During the June 2000 audit, the staff reviewed a variety of screening methodology implementation procedures, including LRS 1-5, "Civil/Mechanical Structure/Component Screening Procedure" and LRS 1-8, "Electrical IPA Procedure." SNC used LRS 1-5 to identify the civil/structural, mechanical, long-lived, passive structures, components, and commodities determined to be within scope and subject to an AMR.

LRS 1-8 was used by SNC to screen electrical components and commodities to determine if they met the criteria of 10 CFR 54.21(a)(i) and (ii) regarding whether an intended function is performed without moving parts or change in configuration or properties and without being replaced based on a qualified life or specified time period. Those components and commodities that meet this criterion are subject to an AMR. SNC used the "spaces approach" described in Sandia National Laboratory's document SAND 96-0344, "Aging Management Guideline for Commercial Nuclear Power Plants - Electrical Cables and Terminations." Starting with a list of structures in the scope of license renewal, they compiled a list of physical in-plant areas which contain in-scope electrical equipment. The areas were further divided using the Fire Hazards Analysis drawings. For these areas, the environmental parameters were

determined (e.g. normal temperature, normal radiation dose rate, normal humidity, and "hot spots"). The applicant performed an extensive in-plant temperature monitoring program to gather measured temperature data. For the list of electrical commodities subject to an aging management review, the applicant then determined the 60-year life based on temperature and radiation dose. These limits were derived from data from the environmental qualification program, manufacturer's published data, and other industry information based on materials of construction. The resultant AMRs were documented in accordance with LRS 1-6, "Aging Management Review Procedure."

As discussed in Section 2.1.3.1 of this SER, the staff concluded that the screening results reviewed by the audit team provided adequate evidence that the scoping and screening process was conducted in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21. However, the staff identified certain discrepancies between the screening process described in the procedures and the actual process that was followed. This issue was the subject of RAI 2.1-1, described above.

2.1.4 Conclusion

On the basis of the staff's review of the information presented in Section 2.1 of the LRA, the supporting information in the Plant Hatch FSAR, the information provided during the scoping and screening audit and inspection, and the applicant's responses to the staff's RAIs, as discussed above, pending satisfactory resolution Open Item 2.1.3.1-1, the staff concludes that there is reasonable assurance that the scoping and screening methodology used by the applicant to identify SSCs within the scope of the Rule, and SCs that are subject to an AMR, is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21.

2.2 Plant Level Scoping Results

2.2.1 Introduction

In Section 2.2, "Scoping Results," of the LRA, the applicant provides the results of its scoping review. The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the applicant has properly identified all plant level systems and structures that are within the scope of license as required by 10 CFR 54.4.

2.2.2 Summary of Technical Information in the Application

Table 2.2-1 of the LRA presents the results of the applicant's plant-wide scoping of systems, structures, and intended functions. The table indicates whether or not the intended functions of a given system or structure is within the scope of license renewal. The applicant states on page 2.2-1 of the LRA that:

> Each function is identified as either in scope or not in scope. Due to the cross-system nature of functions, each function has been assigned to a primary system or structure. However, in many cases the functional boundaries extend into other systems or structures as well. As was described in the scoping/screening methodology,

> Section 2.1, screening of structures/components was performed within functional boundaries. Structures or other features not bearing a system number were assigned to a system or structure and scoped with that system or structure.

This statement means that the results of the applicant's scoping methodology, presented in Table 2.2-1, do not show all intended functions for every system listed. In some cases, intended functions that cross system boundaries are listed under one primary system only. To simplify the staff's review, the applicant provided two comprehensive matrices in an e-mail to William Burton dated May 24, 2000. Amended versions of these matrices were forwarded in an e-mail to William Burton on June 16, 2000. The first matrix provides a correlation of plant systems to their associated intended functions. The second matrix provides a correlation of intended functions to the plant systems that perform each intended function. These matrices are intended to provide a comprehensive correlation between systems and structures and their intended functions.

2.2.3 Staff Evaluation

The staff reviewed Section 2.2 of the LRA to determine if there is reasonable assurance that the applicant has appropriately identified and listed systems and structures that are within the scope of license renewal, pursuant to the Rule. The staff focused its review on verifying that the implementation of the applicant's methodology discussed in Section 2.1 of this SER did not result in the omission of systems and structures from the scope of license renewal. Omission of in scope systems and components would lead to inadequate identification of structures and components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff reviewed selected systems and structures that the applicant identified as not in the scope of license renewal to verify that they do not have any intended functions which would require them to be in scope.

The staff used the FSARs for both units 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 FSAR contains updated plant-specific licensing-basis information regarding the systems, structures, and components (SSCs) and their functions.

The staff sampled the contents of the FSAR by referring to the listing of systems and structures in Table 2.2-1 of the LRA and the system-to-function matrices provided by the applicant to identify systems or structures that may have intended functions, meeting the criteria of 10 CFR 54.4, that the applicant did not include within the scope of license renewal. The staff selected several systems and structures, such as systems that support reactor coolant system integrity and systems that support primary containment cooling. In a letter to the applicant dated July 14, 2000, the staff requested additional information about the scoping results provided in Table 2.2-1.

During the course of this review, the staff identified a concern with regard to the information provided in Table 2.2-1 of the LRA. As noted in Section 2.2.2 of this SER, LRA Table 2.2-1 identifies system functions as being in scope or out of scope. In many cases, when multiple systems had the same function, the applicant grouped these individual system functions under one functional category. When this was done, Table 2.2-1 did not indicate that such a re-categorization had been made. As a result, several systems that would have been within the scope of license renewal based on their normal system function, were identified in Table 2.2-1 as not being within scope, and a function that would place these systems in scope is not listed under the system.

On July 14, 2000, the staff sent the applicant several RAIs related to this section. RAI-2.2-SR-1 requested that the applicant provide an updated Table 2.2-1 because the staff had identified several systems which were clearly within the scope of license renewal, but were not shown in the table as being in scope. Not all of the functions of these systems were listed, and some of the omitted functions placed the system within the scope of license renewal. As noted above, the applicant stated that many SSCs were grouped with other systems by similarity of intended functions; however, the table provided no information on where in the LRA these SSCs are addressed. In its August 29, 2000, RAI response, the applicant stated that the system/function matrices provided in the e-mails on May 24, 2000 and June 16, 2000, provided the requested information. Specifically, the applicant stated, “These matrices provide the capability to efficiently identify the functions that are in scope for any given system and conversely, the systems associated with any given in-scope function.” On the basis of the information provided in the matrices, the staff performed its review to determine whether all intended functions had been identified by the applicant. During the review, the staff identified several additional items that required clarification.

RAI 2.2-SR-2 requested the applicant to clarify the intended function for the primary containment chilled water system (Unit 2 only) listed in Table 2.2-1 of the LRA because it was different from the function described in Section 2.3.4.10 of the LRA. Table 2.2-1 cited drywell cooling as the intended function of this system, putting it in scope for license renewal. However, Section 2.3.4.10 stated that containment integrity was an additional intended function. The applicant stated in the August 29, 2000, RAI response that the correct function was containment integrity. However, the staff identified another inconsistency in reviewing the RAI response. The system-to-function matrix submitted by the applicant listed two intended functions (drywell cooling and containment integrity). By letter dated January 5, 2001, the staff requested the applicant to resolve the discrepancies between the intended function identified in LRA 2.2-1 (drywell cooling only), the intended function identified in the response to RAI 2.2-SR-2 (containment integrity only), and the intended functions identified in LRA Section 2.3.4.10 and the matrices submitted by e-mails on May 24 and June 16, 2000 (drywell cooling and containment integrity). By letter dated January 31, 2001, the applicant responded that it has revised the description of intended function P64-02 in Section 2.3.4.10 of the LRA to clearly indicate that the intended function is primary containment integrity that is provided by the pressure boundary of the drywell cooling subsystem inside containment. A footnote was added to clarify that the “drywell cooling” label is being retained for consistency with the Plant Hatch Maintenance Rule function labels. A similar note was added to Table 2.2-1 of the LRA to show that the label is being retained but the only intended function is primary containment integrity. The letter goes on to state that the system-to-function matrix identifies functions that are in-scope and not in-scope whose boundaries include a part of the system, and cites the primary

containment chilled water as an example. The evaluation boundaries for functions 2C61-01 (primary containment isolation & integrity) and 2P64-02 (drywell cooling) each include one or more primary containment chilled water components. Thus, the system-to-function matrix includes both functions.

The applicant's letter included revisions to Table 2.2-1 of the LRA and Section 2.3.4.10 of the LRA showing the clarifications

On the basis of the information provided by the applicant in its letter dated January 31, 2001, and the accompanying revisions to the table and system description, the staff finds that the applicant has clarified that containment integrity is the only intended function of the primary containment chilled water system.

RAI 2.2-SR-4 requested the applicant to provide the basis for excluding the drywell cooling system (Unit 2 only) from the scope of license renewal. Section 9.4.6.2.1 of the Unit 2 FSAR states that the drywell cooling system is relied upon to maintain the drywell temperature below 165 ^{0}F during a loss of offsite power. In the August 29, 2000, RAI response, the applicant stated that the drywell cooling system is not a safety system and is not relied upon to mitigate a loss-of-coolant accident combined with a loss of offsite power. The applicant further stated that this system is not relied upon to control drywell temperature during a station blackout. The staff agrees with these statements; however, 10 CFR 54.4 requires that non-safety systems whose failure could prevent the satisfactory capability to shut down the reactor or maintain it in a safe shutdown condition also be included in the scope of license renewal. The staff's concern relates to environmental qualification of equipment or sensors in the drywell. It appears from the FSAR that this system may be required to maintain temperature conditions in the drywell during a loss of offsite power so that the applicant can maintain the capability to safely shut down the reactor or maintain it in a safe shutdown condition. The FSAR does not provide any information on the basis for the 165 ^{0}F requirement. In a letter dated January 5, 2001, the staff requested the applicant to provide the basis for the 165 $^{\circ}$F requirement.

By letter dated January 31, 2001, the applicant stated that the neutron monitoring cables are the components at issue. These cables are in the drywell and are not included in the environmental qualification program. Therefore, these cables do not have qualified lives. However, any event which could call into question the operability of the cables would be investigated under the corrective actions program. A temperature spike such as that postulated in the scenario in which a scram occurs simultaneously with a loss of drywell cooling would be the event which would result in a condition report being written, with a corrective action to investigate the condition and operability of the cables. These cables are included in the scope of the insulated cables and connections AMP. This AMP is evaluated in Section 3.1.30 of this SER.

On the basis of the information provided in the applicant's letter dated January 31, 2001, the staff concludes that the drywell cooling system does not perform an intended function and therefore is not in scope.

2.2.4 Conclusions

On the basis of the staff's review of the information presented in Section 2.2 of the LRA, the supporting information in the Plant Hatch FSAR, the applicant's responses to the staff RAIs, and the information provided in the letter dated January 31, 2001, the staff concludes that there is reasonable assurance that the applicant has identified all systems and structures whose intended functions meet the scoping requirements of 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical

2.3.1 Introduction

In Sections 2.3.2, "Reactor Coolant System," 2.3.3, "Engineered Safety Features," 2.3.4, "Auxiliary," and 2.3.5, "Steam and Power Conversion Systems," of the Plant Hatch LRA, the applicant describes the systems and components that are within the scope of license renewal and subject to an AMR. The staff reviewed these sections of the LRA to determine whether there is reasonable assurance that all SSCs within the scope of license renewal have been identified, as required by 10 CFR 54.4(a), and that all components subject to an AMR have been identified, as required by 10 CFR Part 54.21(a)(1).

2.3.2 Reactor Coolant System (RCS)

In Section 2.3.1, "Reactor," and Section 2.3.2, "Reactor Coolant Systems," of the Plant Hatch LRA, the applicant describes the components of the RCS that are within the scope of license renewal and subject to an AMR. The staff reviewed these sections of the LRA to determine whether there is reasonable assurance that all SSCs within the scope of license renewal have been identified, as required by 10 CFR Part 54.4(a), and that all components subject to an AMR have been identified, as required by 10 CFR Part 54.21(a)(1).

2.3.2.1 Summary of Technical Information in the Application

<u>Fuel</u>

Nuclear fuel is fissionable material that can be arranged in a critical array. This high-integrity assembly must be capable of efficiently transferring fission heat to the circulating coolant water while maintaining structural integrity and keeping the fission products contained. The external environment of the fuel is cladding surrounded by water. The fuel cladding experiences the complete range of reactor coolant pressure and temperatures.

System Intended Functions

- Energy Source: The high-integrity assembly of fissionable material efficiently transfers fission heat to the circulating reactor coolant water while maintaining its structural integrity and keeping the fission products contained. The nuclear fuel assembly is the initial barrier to release of fission products. The fuel assembly is designed to ensure that fuel damage does not result in the release of radioactive materials in excess of the guideline values of 10 CFR Parts 20, 50, and 100.

- Spent Fuel Fission Product Barrier: This prevents the release of fission products in the spent fuel. The Zircaloy-2 cladding that covers the spent fuel mitigates the consequences of a fuel handling accident. The cladding ensures that fuel damage does not result in the release of radioactive materials in excess of the guideline values of 10 CFR Parts 20, 50, and 100.

No component groups requiring an AMR are identified in the LRA.

Nuclear Boiler System

The nuclear boiler system generates steam. The functions of the nuclear boiler system are to supply feedwater to the reactor, conduct steam from the reactor, and protect against reactor overpressure. The system also has some reactor control and/or engineered safety feature functions. The nuclear boiler system is in operation any time the plant is in operation. Most of the major components in the system are part of the reactor coolant pressure boundary. The system contains the following major components:

- main steam lines (MSLs)
- safety relief valves (SRVs)
- main steam isolation valves (MSIVs)
- feedwater lines
- feedwater line check valves
- instrumentation and controls

System Intended Functions

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

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

- Rod Worth Minimizer: The rod worth minimizer provides a means of enforcing procedural restrictions on preprogrammed control rod manipulations to limit rod worth to the values assumed in the plant accident analysis (design basis rod drop accident).

- Nuclear Boiler Instrumentation: Nuclear boiler instrumentation provides process information to the operator and signals to other systems in the nuclear power plant.

Component Intended Functions

- Pressure boundary
- Fission product barrier

The component groups requiring an AMR, identified in the LRA are as follows: bolting, crack growth monitor (Class 1), flow restrictor, piping (Class 1 and non-Class 1), restricting orifice (Class 1), thermowell (Class 1 and non-Class 1), and valve bodies (Class 1 and non-Class 1).

<u>Reactor Assembly System</u>

As described in the LRA, the reactor vessel has three major purposes:

- contain core, internals, and moderator.
- serve as a high-integrity barrier against leakage.
- provide a floodable volume.

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

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

System Intended Functions

- The reactor vessel internals distribute coolant to allow power operation without fuel damage and positions and supports the fuel assemblies so that the control rods move properly. The RPV, including the control rods and drives, is evaluated as part of the nuclear boiler system pressure boundary.

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

Component Intended Functions

- pressure boundary
- fission product barrier

- structural support
- flow distribution

The component groups requiring an AMR identified in the LRA are as follows: access hole covers, appurtenances, attachments and connecting welds, closure studs, control rod drive, core ΔP/standby liquid control (SLC) line, core spray internal piping, core spray sparger, core support plate, CRD housing and control rod guide tubes, dry tube weld to guide tube, fuel supports, jet pump assemblies, nozzles, penetrations, safe ends, shell and closure heads, shrouds, shroud supports, shroud tie rods, thermal sleeves, and top guide.

Reactor Recirculation System

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

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

System Intended Functions:

- Recirculating Pump Trip Breaker Trip: The recirculating pump trip (RPT) breakers are designed to trip the reactor on appropriate signals—high reactor vessel steam dome pressure signal, or an indication of an ATWS (anticipated transient without scram)-RPT reactor water level. The RPT breakers trip to prevent the core from exceeding thermal limits during abnormal transients. The system is designed to help the reactor protection system (RPS) protect the integrity of the fuel barrier. This function meets the safe shutdown criteria because the RPS is necessary to allow the control rods or the standby liquid control system to safely and effectively shutdown the reactor.

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

Component Intended Functions

- fission product barrier
- pressure boundary

The component groups requiring an AMR identified in the LRA are as follows: bolting (Class 1), flow nozzle (Class 1), piping (Class 1), pump casings and cover (Class 1), thermowell (Class 1), and valve bodies (Class 1).

2.3.2.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the RCS components and supporting structures within the scope of license renewal, and subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff review is described below.

The staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed parts of the Plant Hatch FSARs and the associated pressure boundary components and the structures and compared the information in the FSAR with the information in the LRA to identify those structures and components that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed structures and components that were identified as not being within the scope of license renewal. The staff requested that the applicant provide additional information and/or clarifications on certain structures and components to verify:

- that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a), and

- for structures and components that have an applicable intended function, either perform the function with moving parts or changes in configurations or properties, or are replaced based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the FSAR to identify any function listed under 10 CFR 54.4(a) that was not identified as an intended function in the LRA, to verify that the function will be maintained for the period of extended operation.

After completing the initial review, the staff issued requests for additional information (RAIs) regarding the RCS, and by letter dated August 29, 2000, the applicant responded to the RAIs, as discussed below.

In RAI 2.3.2-RA-1, the staff asked the applicant to identify the reactor vessel leakage monitoring piping as part of the pressure boundary and, accordingly, to include it in the scope of license renewal and to perform an AMR. If, however, the applicant believed that the component does not require an AMR, the applicant should provide a plant-specific justification as to why the component need not be subject to an AMR. In response, the applicant clarified that the RPV leakage-monitoring piping is in scope. In a June 26, 2000 telephone conference, SNC clarified that the reactor vessel leakage monitoring piping is identified on Table 2.3.1-2 of the LRA as non-Class 1, stainless steel piping. In an e-mail on November 9, 2000, SNC provided the following additional information on this piping.

The Unit 2 piping is shown on drawing HL-26000, grids C/D 3/4. Valve F062 has one inch ASME Section 3 Class 1 piping and valve-to-pressure switch N002 has 3/8-inch Class 2 tubing. As shown on the drawing, these components are within the evaluation boundary for the reactor coolant pressure boundary integrity function (B21-02). Tables 2.3.1-2 and 3.2.1-2 of the LRA list components that support nuclear boiler system intended functions. Thus, the components

are listed in two tables. The material is stainless steel and the environment is reactor water. Thus, on Table 3.2.1-2, non-Class 1, reactor water, and stainless steel piping associated with this function are entered on the last line on page 3.2-5 and Class 1, reactor water, and stainless steel piping associated with this function are entered on the next to last line on page 3.2-6. These line items provide the applicable links for the commodity evaluations and aging management programs.

The Unit 1 piping is shown on drawing HL-16062, grid C/D 3/4. Both 1-inch stainless steel piping and 3/8-inch stainless steel tubing fabricated to ANSI B31.1 requirements, upgraded, are shown to support the reactor coolant pressure boundary integrity function (B21-02). Thus, this piping is listed with the non-Class 1 piping noted above.

On the basis of the applicant's response to this RAI, the staff concludes that the reactor vessel leakage-monitoring piping was identified in the LRA as being within scope and subject to an AMR.

In its review of the applicant's submittal, the staff noticed a footnote in Table 2.3.1-1 of the LRA: "No aging effects requiring management." This footnote applies to the following component groups: access hole covers, core ΔP/SLC line, core support plate, fuel supports, and shroud tie rods. In RAI 2.3.2-RA-2, the staff asked the applicant to provide a basis for the conclusion that no aging effects require management for the above-mentioned component groups. In its response, the applicant stated that the conclusion that there are "no aging effects requiring management" was based on review of the function, materials, and environment of each component, as discussed in the AMR for the components. Furthermore, the applicant stated that the component-specific criteria of the Boiling Water Reactor Vessel Internals Program (BWRVIP) were applied where applicable.

On the basis of the applicant's response to this RAI, the staff concludes that the applicant has provided a basis for the conclusion that the component groups referenced above experience no aging effects requiring management.

In RAI 2.3.2-RA-3, the staff asked the applicant to explain why the intended function of the reactor vessel internals to provide gamma and neutron shielding was not identified on page 2.3-2 or in Table 2.3.1-1 of the LRA. The component specifically designed to perform this function, namely the thermal shield with its supporting structures, was also not identified as within scope and subject to an AMR. The staff believes that the radiation shielding function of the RPV internals should be identified in the LRA and an AMR should be done for those components that perform this passive function. In response, the applicant stated that the BWR internals are not relied upon to provide gamma or neutron shielding. This function is accomplished by the water. Further, the design does not employ a thermal shield. Therefore, there is no need to identify such components in the LRA.

On the basis of the applicant's response to this RAI, the staff concludes that the applicant has provided an adequate explanation of why the function of the reactor vessel internals to provide gamma and neutron shielding was not identified on page 2.3-2 of the LRA or in Table 2.3.1-1 of the LRA.

The low-pressure coolant injection (LPCI) coupling was identified in BWRVIP-06, “Safety Assessment of BWR Reactor Internals,” as a safety-related component. In RAI 2.3.2-RA-4, the staff asked the applicant to identify the AMR for the LPCI coupling in the LRA or justify the exclusion of this component from aging management review. The applicant responded that the use of an LPCI coupling is limited to three BWR/4 plants and BWR/5 and BWR/6 plants and that neither Plant Hatch unit has an LPCI coupling. Therefore, it was not mentioned in the LRA.

On the basis of the applicant’s response to this RAI, the staff concludes that the applicant has provided an adequate justification for the exclusion of this component from aging management review.

In RAI 2.3.2-NBS-1, the staff asked the applicant to clarify why the safety relief valve (SRV) discharge lines and their supports have not been identified in Table 2.3.1-2 as component groups requiring an AMR. The staff believes that these structures and components perform the passive function of withstanding significant loads, such as SRV discharges, and that their failure can defeat the SRVs’ intended safety function. The applicant verified that the SRV discharge lines and supports have been identified in the application as components subject to an AMR, and clarified that the SRV discharge lines are scoped as part of the pressure control function (B21-01). The components are shown on boundary diagrams HL-16062 and HL-26000. Table 2.3.1-2 identifies the SRV discharge lines as piping. The applicant further clarified that the pipe supports for the SRV discharge lines are scoped as part of the pipe support function (L35-01) and identified in Section 2.4.1 of the LRA, "Piping Specialties." Table 2.4.1-1 lists the pipe supports for the SRV discharge lines as hangers and supports for non-ASME Class 1 piping, tubing, and ducts.

On the basis of the applicant’s response to this RAI, the staff concludes that the applicant has clarified that the SRV discharge lines and its supports are identified as requiring an AMR.

In RAI 2.3.2-NBS-2, the staff stated that only two intended functions were identified for flow-restricting orifices (Table 2.3.1-2 of the LRA): pressure boundary and fission product barrier. However, some orifices are relied upon to limit mass flow rate during postulated breaks, and loss of material can degrade this function. The staff asked the applicant to show why limiting mass flow rate during postulated breaks is not an intended function of some orifices, per 10 CFR 54.4(a)(1)(iii), or provide an AMR for the orifices that have an intended function to limit mass flow rate. In response, the applicant acknowledged that some of the orifices are in fact relied upon to limit mass flow rate during postulated breaks, and that the component function, namely, “flow restriction”, was inadvertently omitted from restricting orifice line items in Tables 2.3.1-2 and 3.2.1-2 of the LRA. The staff notes that the applicant has modified the tables accordingly, as shown below. In addition, the flow restriction elements (venturi) of 1/2B21-N005A-D shown on boundary drawings HL-16062 and HL-26000 are credited for restricting the main steam flow and for limiting the mass flow rate during postulated breaks. Thus they perform an intended function and are subject to an AMR. The applicant submitted its revised AMP as part of this RAI response, as shown below. The revised AMP addresses the flow restriction as an intended function, so that this function of the component will be maintained for the extended period of operation. The adequacy of the AMP to manage and maintain the flow restriction function is discussed in Sections 3.1.1 and 3.1.12 of the SER for the reactor water chemistry control and component cyclic transient limit programs, respectively.

Revised Section of Table 2.3.1-2

Mechanical Component	Component Functions	Material
Main Steam Flow Restrictor - Pipe (Class 1)	Pressure Boundary Fission Product Barrier	Carbon Steel
Main Steam Flow Restrictor - Venturi	Flow Restriction	Cast Austenitic Stainless Steel

Revised Section of Table 3.2.1-2:

Mechanical Component	Component Functions	Environm-ent Effects	Material	Aging Effects	Aging Mgmt Program
Main Steam Flow Restrictor - Pipe/ C.2.1.1.3 (Class1)	Pressure Boundary Fission Product Barrier	Reactor Water	Carbon Steel	Loss of Material Cracking	Reactor Water Chem. Control Inservice Inspection Prog. Galvanic Susceptibility Inspections Component Cyclic or Transient Limit Prog. Flow Accelerated Corrosion Prog.Treated Water Systems Piping Inspections
Main Steam Flow Restrictor-Venturi/ C.2.1.1.5	Flow Restriction	Reactor Water	Cast Austenitic Stainless Steel	Loss of Material Cracking	Reactor Water Chem. Control Component Cyclic Transient Limit Prog.

The staff asked the applicant to clarify “main steam flow restrictor - pipe” in the above tables. In response, the applicant states that this is merely the name of section the piping that includes the venturi, and that the pipe does not have a flow restriction function. The flow restriction function only applies to the venturi.

On the basis of the applicant’s response to this RAI, the staff concludes that the applicant has identified orifices that provide an in-scope function to limit mass flow rate during postulated breaks.

In addition to the RAIs discussed above, the staff held several telephone conference calls with the applicant to clarify the applicant’s positions on some of the issues. In the call on June 26, 2000, the staff asked for justification for the decision to exclude the following vessel internals from the scope of license renewal: steam dryer, core shroud head and separators, feedwater spargers, and surveillance capsule holder. The applicant stated that consistent with BWRVIP-06, these SSCs are not safety-related. The applicant also stated that failure of these non-safety-related SSCs would not adversely affect the ability of the safety-related SSCs to perform their functions, and that this is consistent with industry comments to NRC on the Generic Aging Lessons Learned (GALL) report.

On the basis of the applicant’s responses during this call, the staff concludes that the applicant has provided an adequate justification for excluding the vessel internals discussed above from the scope of license renewal.

In the call made on June 29, 2000, the staff expressed concern that blockage of the spray holes of the core spray spargers through aging could keep the core spray system from performing its intended function of spraying the fuel bundles following a LOCA. The applicant replied that, because the core spray piping is made of stainless steel, corrosion is not a credible aging mechanism to cause flow blockage. The applicant further stated that BWRVIP-18, “Core Spray Internals Inspection and Flaw Evaluation Guidelines,” provides a means to inspect the core spray piping. Finally, the applicant stated that adequate core spray distribution is not an assumption or requirement in the LOCA analysis of BWR-4s, including Plant Hatch.

On the basis of the applicant’s responses during this call, the staff concludes that the applicant has provided an adequate justification for concluding that blockage of the spray holes through aging of the core spray piping is not a credible aging mechanism.

2.3.2.3 Conclusions

The staff has reviewed the information in Sections 2.3.1, “Reactor,” and 2.3.2, “Reactor Coolant System,” of the LRA. In its review, the staff identified an omission by the applicant. Specifically, the applicant had not evaluated orifices for the intended function of limiting mass flow rates during postulated breaks. The applicant subsequently evaluated the orifices and identified those that performed an in-scope function and revised the appropriate tables in the LRA. On the basis of this review, the staff concludes that the applicant has identified those components within the scope of license and that are subject to an AMR, as required by 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.3.3 Engineered Safety Features (ESF)

The applicant described the components of the systems and components of the engineered safety features systems that are within the scope of license renewal and the subject to an AMR, in the following sections of the LRA: Section 2.3.3.1, “Standby Liquid Control System”; 2.3.3.2, “Residual Heat Removal System”; 2.3.3.3, “Core Spray System”; 2.3.3.4, “High Pressure Coolant Injection System”; 2.3.3.5, “Reactor Core Isolation Cooling System”; 2.3.3.6, “Standby Gas Treatment System”; 2.3.3.7, “Primary Containment Purge and Inerting System”; and 2.3.3.8, “Post LOCA Hydrogen Recombiner System (Unit 2 Only).” The staff reviewed these sections of the LRA to determine whether there is reasonable assurance that all components have been identified as being within the scope of license renewal, as required by 10 CFR 54.4(a), and that all components subject to an AMR have been identified, as required by 10 CFR 54.21(a)(1).

2.3.3.1 Summary of Technical Information in the Application

Core Spray System

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

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

System Intended Functions

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

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

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

Component Intended Functions

- Pressure boundary
- Fission product barrier
- Flow restriction
- Debris protection

The component groups requiring an AMR, are as follows: bolting, piping, pump casings, restricting orifice, strainers, and valve bodies.

<u>High Pressure Coolant Injection</u>

The high pressure coolant injection (HPCI) system supplies makeup coolant into the reactor vessel from a fully pressurized to a preset depressurized condition. Demineralized makeup water is supplied from the condensate storage tank (CST) or treated water from the suppression pool. The flow rate of the system will maintain the reactor vessel coolant inventory until the reactor pressure drops sufficiently to permit the low pressure core cooling systems to automatically inject coolant into the vessel. The HPCI system consists of a turbine driven pump train, piping, valves, and controls that provide a complete and independent emergency core cooling system (ECCS). A test line permits functional testing of the system during normal plant operation. A minimum flow bypass line bypasses pump discharge flow to the suppression pool to protect the pump in the event of a stoppage in the main discharge line. Reactor vessel steam is supplied to the turbine. Turbine exhaust steam is then dumped to the suppression pool.

System Intended Functions

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

Component Intended Functions

- Pressure boundary
- Fission product barrier
- Structural support
- Flow restriction
- Debris protection

The component groups requiring an AMR, as identified in the LRA, are as follows: bolting, flexible connectors, piping, pump baseplate, pump casings, restricting orifice, suction strainer, thermowell, turbine, and valve bodies.

Post-LOCA Hydrogen Recombiners (Unit 2 Only)

The post-loss-of-coolant accident (LOCA) hydrogen recombiner (hydrogen recombiner) system is designed as the combustible gas control system to ensure that hydrogen is not accumulated within the primary containment to combustible concentrations following a LOCA. In Section 2.3.3.8, “Post LOCA Hydrogen Recombiner System,” of the LRA, the applicant described the intended functions and listed the components of the system that are subject to an AMR. The applicant described their process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, “Scoping,” and Section 2.1.3, “Civil/Mechanical Component Screening,” of the LRA.

In Section 2.3.3.8 of the LRA, the applicant described the intended functions of the hydrogen recombiner system. The system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations flowing a LOCA. This is accomplished by drawing primary containment atmosphere from the drywell and passing it through the recombiner where the hydrogen reacts with available oxygen to form water vapor. The recombiner discharge is to the suppression pool (torus). The hydrogen recombiner system is part of the combustible gas control system and consists of two identical independent 100% capacity trains. Each train consists of three packages: the recombiner skid, the control console, and the power panel. The recombiner skid consists of inlet piping, flowmeters, flow control valve, an enclosed blower assembly, heater section, reaction chamber, direct contact water spray connected to the power panel, and the control console through instrument and power cables. Coolant for the water spray gas cooler is provided by the residual heat removal (RHR) system.

The initial scoping, performed by the applicant and based on the system functions, has determined the following intended function for the hydrogen recombiner system to be within the scope of license renewal.

T49-01 – Containment Combustible Gas Control: The hydrogen recombiner system ensures that hydrogen does not accumulate within the primary containment in combustible concentrations following a LOCA. This function (containment combustible gas control) applies to Unit 2 only.

The associated piping, valve bodies, and bolting are identified in Table 2.3.3-8 of the LRA as being subject to an AMR. The component functions for the piping, valve bodies, and bolting are the pressure boundary and fission product barrier.

Primary Containment Purge and Inerting System

The primary containment purge and inerting (purge and inerting) system is designed to supply and maintain an inert atmosphere inside primary containment for combustible gas control and

fire protection. In addition, it is designed to purge and vent the containment atmosphere and provide vacuum relief between the torus and drywell as well as between the torus and reactor building. In Section 2.3.3.7 of the LRA, the applicant described the intended functions and the components of the system that are subject to an AMR.

In Section 2.3.3.7 of the LRA, the applicant described the primary function of the containment purge and inerting system in inerting the primary containment. Plant Technical Specifications require that within 24 hours of reactor operation, the inerting system injects a sufficient amount of gaseous nitrogen into the drywell and torus so that the oxygen concentration falls below 4% by volume. Major equipment for the purge and inerting system includes a purge air supply fan, liquid nitrogen storage tank, ambient vaporizer, steam vaporizer, vacuum breaker, valves, piping, controls, and instrumentation. In addition, the primary containment purge and inerting system provides containment vent paths to the standby gas treatment system, which provides a vent path to the main stack for containment vent and purge operations.

The initial scoping, performed by the applicant and based on the system functions, has determined the following intended functions for the purge and inerting system to be within the scope of license renewal.

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

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

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

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

The associated piping, valve bodies, bolting, flex hose, nitrogen tank jacket, pressure buildup coil, rupture disc, storage tank, thermowell, and vaporizer are identified in Table 2.3.3-7 of the LRA as being subject to an AMR. The component function for piping, valve bodies, bolting, rupture disc, storage tank, and thermowell is pressure boundary; the functions for the flex hose are pressure boundary and fission product barrier; the function for the nitrogen tank jacket is structure support; the functions for the pressure buildup coil and vaporizer are pressure boundary and heat exchange.

Reactor Core Isolation Cooling System

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

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

System Intended Functions

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

Component Intended Functions

- Pressure boundary
- Fission product barrier
- Structural support
- Flow restriction
- Debris protection

The component groups requiring an AMR, as identified in the LRA, are as follows: bolting, flexible connector, piping, pump baseplate, pump casing, restricting orifices, steam trap, strainer-steam exhaust, suction strainer, thermowell, turbine, and valve bodies.

Residual Heat Removal (RHR) System

The RHR system is composed of several components and subsystems which are required to:

- Restore and maintain reactor vessel water level after a loss of coolant accident (LOCA);

- Limit temperature and pressure inside the containment after a LOCA;

- Remove heat from the suppression pool water; and

- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

The RHR system consists of four pumps and two heat exchangers divided into two loops of two pumps and one heat exchanger each, plus the associated instruments, valves, and piping. The RHR pumps take suction from the suppression pool or the reactor coolant recirculation loop.

The pumps discharge into the recirculation loop, the suppression pool, the containment spray headers, or the spent-fuel pool cooling and cleanup system, depending upon the desired mode of system operation. The RHR system interfaces with the reactor recirculation system to provide a flow-path in support of shutdown cooling and low pressure coolant injection (LPCI). The RHR system is part of the reactor coolant pressure boundary; therefore, it also maintains the pressure boundary during normal operation, transients, and accident scenarios to prevent the release of radioactive liquid and gas. The RHR system is cooled through the heat exchangers by the residual heat removal service water (RHRSW) system. The RHRSW takes suction from the Altamaha River. There are four RHRSW pumps per unit. The RHRSW system also serves as a standby coolant supply system by providing a means of injecting makeup water from the river to the RHR system to keep the core covered during an extreme emergency.

System Intended Functions

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

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

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

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

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

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

Component Intended Functions

- Pressure boundary
- Fission product barrier
- Shelter/ protection

- Structural support
- Flow restriction
- Debris protection

The component groups requiring an AMR, are as follows: bolting, conductivity element, heat exchanger channel assembly, heat exchanger impingement plate, heat exchanger shell, heat exchanger tube sheet, heat exchanger tubes, piping, pump casings, pump casing - bowl assembly, pump discharge head, pump sub base, restricting orifices, strainer bodies, strainers, thermowell, tubing, and valve bodies.

Standby Gas Treatment System

In LRA Section 2.3.3.6, "Standby Gas Treatment System," of the LRA, the applicant described the components of the standby gas treatement system (SGTS) that are within the scope of license renewal and subject to an AMR. The staff reviewed this section of the LRA to determine whether there is reasonable assurance that all components have been identified as being within the scope of license renewal, as required by 10 CFR 54.4(a), and that all components subject to an AMR have been identified as required by 10 CFR Part 54.21(a)(1).

The applicant stated in Section 2.3.3.6 of the LRA that additional information for the SGTS is provided in Sections 5.3.3.3 and 6.2.3 of the FSAR for Units 1 and 2, respectively. The system scoping is shown in SGTS evaluation boundary drawings HL-16020, Rev. A and HL-16174, Rev. A for Unit 1, and HL-26078, Rev. A for Unit 2.

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

Plant Hatch Unit 1

The SGTS suction from the reactor building below the refueling floor and torus and drywell area is isolated during refueling activities by gagging closed certain valves in the reactor building suction lines to achieve modified secondary containment. Following the receipt of the isolation signal, the reactor zone and/or refueling zone isolation dampers close, supply and exhaust fans are shut off, and the SGTS is initiated. The SGTS system minimizes the release of radioactive material to environs by filtering and exhausting via the main stack.

The basic SGTS consists of two identical parallel air filtration assemblies (trains) separated by a 42-inch-thick concrete wall and enclosed within a seismic Class 1 structure. The 18-in. underground discharge pipe leading to the main stack is seismic Class 1. Each train is full capacity and consists of a demister or moisture separator, electrical heating coil, pre-filter, high-efficiency particulate air (HEPA) filter, two charcoal adsorbers, final HEPA filter, and exhaust fan.

The total free volume of the secondary containment system is approximately 2 x 10^6 ft^3 and the portion of the volume above the refueling floor is 725,000 ft^3. Based on the secondary

containment system free volume, each SGTS train has the capability equal to two air volume changes per day (assuming no wind). The discharge lines from the Unit 1 trains tie together into an 18-in. header for discharge into the main stack. Unlike the Unit 2 SGTS, the Unit 1 SGTS is designed with a timer logic such that trains A and B are set to trip at approximately 6 and 4 minutes, respectively, from initial start on sensing low airflow conditions. The details of the SGTS are described in Section 5.3.3.3 of the Unit 1 FSAR.

Plant Hatch Unit 2

The SGTS is fully redundant and capable of performing following a single failure. In the event of a Loss of Offsite Power (LOSP), the SGTS fans can be powered from the emergency service portions of the auxiliary power distribution system. The fan associated with each filter assembly is powered from a different emergency diesel in the event of LOSP. The system includes isolation dampers which fail open on loss of power to the solenoids or upon loss of instrument air to the air operators on the dampers. An interlock with the associated exhaust fan prevents the heating coil from operating when the fan is shut down. The system components and ductwork meet seismic Category I requirements.

In the event of an automatic initiation signal for the SGTS, the normally operating reactor building and refueling floor ventilation systems are isolated. Since other boundary penetrations such as access doors or electrical cables are normally sealed, the only potential fission product release path is through the SGTS to the main stack. Further, since no air path other than infiltration exists for replacement air, the area within the boundary connected to the SGTS is maintained at a negative pressure.

The SGTS automatically filters the exhaust air from the reactor building and/or the fuel handling area following an accident. As an alternate mode of operation, the drywell and/or torus purge exhaust are manually directed to the SGTS for processing before release up the main stack.

The SGTS consists of two identical, redundant, parallel air filtration assemblies separated by a 4-ft 6-in.-thick concrete wall which are completely enclosed within a seismic Category I structure. Each of the filtration assemblies and their respective components are designed for 100-percent-capacity operation. Each filtration assembly consists of a demister or moisture separator to reduce absolute humidity, electric heater for relative humidity control to maintain the adsorption efficiency of the carbon bed, pre-filter for removal of larger particulates to protect the high-efficiency particulate air (HEPA) filter, final HEPA filter for removal of postulated particulate matter that could be carried off the carbon adsorber by the air stream, and an exhaust fan to move the air. With the reactor building isolated, each of the two exhaust fans has the necessary capacity to reduce and hold the reactor building at a minimum negative pressure of 0.20-in. water. The details of the SGTS are described in Section 6.2.3 of the Unit 2 FSAR.

In Section 2.3.3.6 of the LRA, the applicant identified the following intended functions for the SGTS that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and
10 CFR 54.4(a)(3):

- To minimize the release of radioactive materials to the environment during accident conditions.

- To ventilate and cleanup the primary and secondary containment during certain postulated DBAs.

On the basis of the functions identified above, the applicant determined that all SGTS safety-related components (electrical, mechanical, and instrument) are within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the SGTS that are within the scope of license renewal in SGTS evaluation boundary drawings HL-16020, Rev. A and HL-16174, Rev. A for Unit 1, and HL-26078, Rev. A for Unit 2 of the LRA. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the mechanical components and component types within the scope of license renewal and that are subject to AMR and identified their functions. The applicant provided this list in Table 2.3.3-6 of the LRA.

The applicant identified the following 11 device types that are identified as within the scope of license renewal and that are subject to an AMR:

- filter housing (galvanized steel)
- piping (carbon steel)
- piping (stainless steel)
- piping (copper)
- piping (galvanized steel)
- rupture disc (stainless steel)
- thermowell (stainless steel)
- valve bodies (gray cast iron)
- valve bodies (carbon steel)
- valve bodies (stainless steel)
- valve bodies (copper alloy)

In Table 2.3.3-6, the applicant further noted that the SGTS fission product barrier and pressure boundary functions are the only applicable functions associated with components of the SGTS that are subject to an AMR.

<u>Standby Liquid Control System (SLCS)</u>

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

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

System Intended Functions

- Reactivity control: The SLCS assures reactor shutdown from full power operation to cold subcritical by mixing a neutron absorber with the primary reactor coolant.

- SLCS testing

Component Intended Function

- Pressure boundary

The component groups requiring an AMR, as identified in the LRA, are as follows: bolting, piping, pump accumulators, pump casings, tanks, temperature element, temperature switch and valve bodies.

2.3.3.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the ESF components and supporting structures within the scope of license renewal, and subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed portions of the FSAR for the ESF and associated pressure boundary components and compared the information in the FSAR with the information in the LRA to identify those portions that the LRA did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed structures and components that were identified as not being within the scope of license renewal. The staff requested that the applicant provide additional information and/or clarifications for a selected number of these structures and components to verify the following:

- that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a), and

- for those structures and components that have an applicable intended function(s), verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed the FSAR for any function(s) delineated under 10 CFR 54.4 (a) that were not identified as intended function(s) in the LRA, to verify that the systems, structures, and components with such function(s) will be adequately managed so that the function(s) will be maintained for the extended period of operation.

After completing the initial review, the staff issued requests for additional information (RAIs) regarding the ESF, and by letter dated August 29, 2000, the applicant submitted responses to those RAIs, as discussed below.

In RAI 2.3.3-ESF-1, the staff indicated that in Section 2.3.3 of the LRA, tanks (including the vertical tanks erected in the field) are considered mechanical components. However, the tank foundation and anchorage systems are considered structural components. Tanks can have foundations that are made of concrete or steel. The staff requested the applicant to clarify whether the concrete foundations or pads of the tanks needed for the ESF systems are included within the scope of license renewal and whether they are subject to an AMR. In response, the applicant verified that tank foundations and anchorage supporting ESF systems are in scope and subject to AMR. The applicant clarified that tank foundations are evaluated as a structure (either as part of a building or as a yard structure). Each table that includes a tank foundation (building or yard structure) also identifies anchors and bolts associated with the tank anchorage system. On the basis of the applicant's response to this RAI, the staff concludes that applicant has identified the ESF tank foundations as being within the scope of license renewal and subject to an AMR. Section 2.4 of the LRA identifies structural components subject to AMR. The staff's evaluation of structural components is found in Section 2.4 of this SER.

In RAI 2.3.3-ESF-2, the staff requested the applicant to verify whether the passive components, namely screens and vortex breakers, used in pump suction lines, whose intended function is to protect the pumps from debris and cavitation, respectively, and which could be located either inside the ESF tanks or in the sump, are subject to an AMR. If so, identify which tanks and sumps are equipped with these passive components and the location of the AMRs in the LRA for these components. If not, to provide justification for exclusion of these components from an AMR. The applicant stated in it's response that "Screens" used within ESF tanks would be considered long-lived, passive components subject to an AMR. The applicant further stated that at Plant Hatch, the only "screens" utilized within ESF tanks to protect ESF system pump suctions from debris are pump suction strainers located within the torus. These strainers protect the pump suctions for the following systems: Residual Heat Removal, Core Spray, High Pressure Coolant Injection, and Reactor Core Isolation Cooling. These strainers are included within the Plant Hatch LRA in sections 2.3.3.2, 2.3.3.3, 2.3.3.4, and 2.3.3.5. The applicant acknowledged that vortex-breaking devices would also be considered long-lived, passive components subject to an AMR. However, neither unit at Plant Hatch utilizes vortex breakers within the torus, the condensate storage tank, or the SLC storage tank. On the basis of the applicant's response to this RAI, the staff concludes that applicant has identified screens as being within the scope of license renewal and subject to an AMR, and that vortex breakers are not used in ESF tanks.

<u>Core Spray System</u>

The staff was concerned that blockage of the spray holes of the core spray spargers, could prevent the core spray system from performing its intended function by preventing adequate distribution of the spray on the fuel bundles. The staff discussed this issue with the applicant in telephone conferences on June 26 and June 29, 2000. SNC stated that, because the core spray piping is made of stainless steel, corrosion is not a credible aging mechanism to cause flow blockage. Also, SNC stated that BWRVIP-18, "Core Spray Internals Inspection and Flaw Evaluation Guidelines," provides means to inspect the core spray piping. Finally, SNC clarified that adequate core spray distribution is not an assumption or requirement in the accident analyses. On the basis of the staff's review of the information provided in the LRA, and information provided in the telephone conferences with the applicant, the staff concludes that

the applicant has properly identified the components associated with the core spray system within the scope of license renewal, as required by 10 CFR Part 54.4(a), and has properly identified the components subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

High Pressure Coolant Injection System

On the basis of the staff's review of the information provided in the LRA, and described in Section 2.3.3.1 of this SER, for the high pressure coolant injection system, the staff concludes that the applicant has properly identified the components associated with the high pressure coolant injection system within the scope of license renewal, as required by 10 CFR Part 54.4(a), and has properly identified the components subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

Post-LOCA Hydrogen Recombiners System

The applicant identified and listed the components subject to an AMR for the hydrogen recombiner system in Table 2.3.3-8 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The staff reviewed Plant Hatch Unit 2 FSAR Section 6.2.5 to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the associated boundary drawing HL-26068 to verify that the applicant identified all the components within the scope of license renewal in accordance with 10 CFR 54.4. Further, the staff verified the accuracy of the drawings and the completeness of Table 2.3.3-8 by sampling the components adjacent to, but outside, the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were identified as being subject to an AMR.

After the initial review, the staff identified, in a letter dated July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAIs in a letter dated August 29, 2000.

In response to RAI 2.3.3-HR-2, the applicant clarified that an unnamed component "B001A" in Drawing No. HL-26068, identified by MPL number 2T49-B001A, is the heater subcomponent of the skid-mounted hydrogen recombiner, 2T49-Z001A. The heater serves to preheat containment gases prior to combustion in the reaction chamber.

In response to RAI 2.3.3-HR-3, the applicant also confirmed that Plant Hatch Unit 1 does not use a hydrogen recombiner for post-LOCA hydrogen controls. It uses the inerted nitrogen gas to prevent explosive concentrations of hydrogen and oxygen. Therefore, the post-LOCA hydrogen recombiner system, described in Section 2.3.3.8 of the LRA, applies to Unit 2 only.

In RAI-2.3.3-HR-1 and RAI-2.3.3-HR-4, the staff asked the applicant to justify its exclusion of the following components (highlighted in HL-26068) from an AMR: water separator, water spray

cooler, reaction chamber, blower (C0001A), heater (B001A), and instrument tubing. The applicant responded that these components are a part of skid-mounted hydrogen recombiners, which are active components, and thus not subject to an AMR. Therefore, the applicant determined that the components are also not subject to an AMR.

In a telephone conference, dated September 13, 2000, the staff expressed its disagreement with the applicant's determination to exclude these components from an AMR simply because these components are skid-mounted. The staff requested the applicant to provide additional justification for its position. In response, the applicant provided a paper, entitled "Active Assemblies Used in License Renewal," via an email, dated November 6, 2000.

The staff has reviewed this paper, and finds that the applicant's basis for excluding hydrogen recombiner components, as discussed in the paper, is not consistent with the license renewal rule. The basis for the staff's conclusion summarized below and is described in more detail in Section 2.3.4.2 of this report discussing the emergency diesel generators.

Components are subject to an AMR if they perform a passive function and are long-lived. A passive function is one performed without moving parts or a change in configuration or properties. A function performed with moving parts or a change in configuration or properties is considered an active function. Components that perform a passive function and are also long-lived must be subject to an AMR, whether they are skid-mounted or not. The staff believes that the water separator, water spray cooler, and reaction chamber are long-lived components with a passive function, and therefore are subject to an AMR. On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components performing a passive function associated with the hydrogen recombiners, and identify AMPs credited with managing the aging effects. This is part of Open Item 2.3.3.2-1.

On the basis of the staff's review of the LRA and associated drawings, the Plant Hatch Units 1 and 2 FSARs, and the applicant's responses to RAIs, pending satisfactory resolution of Open Item 2.3.3.2-1, the staff concludes that the applicant has identified the components of the post-LOCA hydrogen recombiners system that are within the scope of license renewal and subject to an AMR.

Primary Containment Purge and Inerting System

The applicant identified and listed the components subject to an AMR for the purge and inerting system in Table 2.3.3-7 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The staff reviewed Plant Hatch Unit 1 FSAR Sections 5.2.3.8 and 5.2.3.9 and Unit 2 FSAR Section 6.2 to determine if there were any system functions not identified as intended functions in accordance with the requirements of 10 CFR 54.4. The staff then reviewed the evaluation boundary drawings (HL-16024, HL-16000, HL-16239, HL-16153, HL-16286, HL-26084, HL-26079, HL-26083, and HL-26020) to verify that the applicant identified all the components within the scope of license renewal in accordance with 10 CFR 54.4. Further, the staff verified the accuracy of the drawings and the completeness of Table 2.3.3-7 by sampling the

components adjacent to, but outside the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were identified as being subject to an AMR.

After the initial review, the staff identified, in a letter dated July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAIs in a letter, dated August 29, 2000.

In RAI 2.3.3-P&I-1, the staff requested the applicant to clarify whether the "vaporizer", listed in Table 2.3.3.7 of the LRA, represents the ambient vaporizer only, or both the ambient and steam vaporizers. In Section 2.3.3.7 of the LRA, both the ambient vaporizer and steam vaporizer are identified as major equipment for the system. The applicant responded that the "vaporizer" listed in Table 2.3.3.7 of the LRA stands for the ambient vaporizer only. The steam vaporizer does not perform an intended function. Therefore, it is not within the scope of license renewal.

In RAI 2.3.3-P&I-3, the staff questioned the basis for excluding instrument tubing from an AMR. The applicant responded that, with the exception of copper, the LRA includes instrument tubing with piping for like materials. There is no copper instrument tubing in scope for functions associated with the primary containment purge and inerting system. On the basis of the information provided in the applicant's response to RAI 2.3.3-P&I-3, the RAI is resolved.

To verify that the applicant identified all the components within the scope of license renewal in accordance with 10 CFR 54.4, the staff reviewed the intended functions (primary containment nitrogen inerting [T48-01], primary containment vacuum relief [T48-03], containment/reactor building parameter monitoring [T48-04], and and drywell pneumatic nitrogen supply [T48-06]) along with nine evaluation boundary drawings (HL-16024, HL-16000, HL-16239, HL-16153, HL-16286, HL-26084, HL-26079, HL-26083, and HL-26020). Each drawing has a large number of components associated with several overlapping functions, and each drawing may have several systems. Each intended function may be cross-referenced in several drawings. In RAI 2.3.3-P&I-2, the staff requested the applicant to identify all the drawings and major components associated with function T48-03, "Primary Containment Vacuum Relief." In its response, the applicant referred to drawings HL-16024 and HL-26084, but did not identify any of the components being used for T48-03 function. The applicant stated that Plant Hatch LRA does not present screening results on a function-by-function basis. Rather, all functions primarily associated with the system are grouped together for screening, and the results of the screening are listed in Table 2.3.3-7. Based on the available information and the RAI response, it was not clear to the staff whether the applicant had properly identified all components within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

To resolve the above concern, the staff included the purge and inerting system in its scoping and screening inspection, which was performed at the applicant's corporate offices in Birmingham, Alabama, during the week of September 11, 2000 through September 15, 2000. During the inspection, as documented in NRC Inspection Report 50-321/00-09, 50-366/00-09, the NRC inspector reviewed additional on-site information associated with the system and concluded that the applicant had correctly identified the components subject to an AMR, as well

as components not subject to an AMR. Based on the results of this inspection, the staff agrees with the applicant that all the components subject to an AMR are properly identified in Table 2.3.3.7 of the LRA.

On the basis of the NRC inspection and review of the LRA and associated drawings, the Plant Hatch Units 1 and 2 FSARs, and the applicant's responses to RAIs, the staff was unable to find any omissions from the components highlighted in the diagrams that identify the function level scoping boundaries. The staff also compared the components listed in Table 2.3.3-7 of the LRA to the components highlighted in the drawings, and found them consistent.

On the basis of the review, the NRC staff has determined that there is reasonable assurance that the applicant has adequately identified the intended functions of the primary containment purge and inerting system that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4 and the components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Reactor Core Isolation Cooling System

The staff reviewed Section 2.3.3.5 of the LRA to determine whether the applicant has identified the components in the reactor core isolation cooling system that are within the scope of license renewal and subject to an AMR, as required by 10 CFR 54.4 and 10 CFR 54.21(a)(1).

On the basis of the staff's review of the information provided in the LRA, and described in Section 2.3.3.1 of this SER, for the reactor core isolation cooling system, the staff concludes that the applicant has properly identified the components associated with the reactor core isolation cooling system that are within the scope of license renewal, as required by 10 CFR Part 54.4(a), and has properly identified the components that are subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

Residual Heat Removal System

In RAI 2.3.3-RHR–1, the staff indicated that in Table 2.3.3-2 of the LRA, the intended functions for heat removal tubes have been identified as fission product barrier and pressure boundary. However, the staff believes that heat transfer is also an intended function of this component. The applicant was requested to explain why this additional function need not be identified, and why an AMR is not necessary to assure satisfactory performance of this function during the period of extended operation. The applicant responded by stating that although it was not listed in Table 2.3.3-2, heat transfer is part of the component function for the RHR heat exchanger tubes. The applicant stated further that it was inadvertently omitted from the table, and that although the function was not listed in the table, the AMR performed for the heat exchanger tubes in Section C.2.2.11 of the LRA included consideration of this function in the evaluation of aging effects requiring aging management.

On the basis of the staff's review of the information provided in the LRA, described in Section 2.3.3.1 of this SER, for the residual heat removal system, as well as the response to the staff's RAI, the staff concludes that the applicant has properly identified the components

associated with the residual heat removal system that are within the scope of license renewal, as required by 10 CFR Part 54.4(a), and has properly identified the components that are subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

Standby Gas Treatment System

The staff reviewed Section 2.3.3.6 of the LRA to verify that the applicant identified the SGTS components within the scope of license renewal. The staff determined whether there is reasonable assurance that the SGTS components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.21(a)(1). The staff reviewed other information in the LRA and Sections 5.3.3.3 and 6.2.3 of the FSAR for Units 1 and 2, respectively. After completing the initial review, the staff issued a request for additional information (RAI) by letter dated July 14, 2000, regarding the SGTS. The applicant responded to the RAI by letter dated August 29, 2000.

In LRA Section 2.1, the applicant discussed the process of identifying mechanical components subject to an AMR. The applicant's scoping methodology is evaluated by the staff in Section 2.1 of this SER.

In its review of the SGTS, the staff reviewed the SGTS evaluation boundary drawings HL-16020, Rev. A and HL-16174, Rev. A for Unit 1, and HL-26078, Rev. A for Unit 2 of the LRA. The drawings show the evaluation boundaries for the portions of the SGTS within the scope of license renewal. The staff also reviewed Table 2.3.3-6 of the LRA that lists those mechanical components subject to an AMR.

The staff also reviewed Sections 5.3.3.3 and 6.2.3 of the FSAR for Units 1 and 2, respectively, to determine if there were any portions of the SGTS that met the scoping criteria in 10 CFR 54.4 that the applicant did not identify as within the scope of license renewal. The staff also reviewed the FSAR sections to determine if there was a system function that was not identified as an intended function in the LRA, and to determine if there were structures and components (SCs) that have an intended function that might have been omitted from the scope of SCs requiring an AMR. The staff also reviewed the above SGTS evaluation boundary drawings to determine if any SCs within the evaluation boundaries were omitted from the scope of SCs requiring an AMR under 10 CFR 54.4(a)(1). The staff compared the system and intended functions described in the FSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified SCs subject to AMR from among those identified as within the scope of license renewal.

The applicant identified and listed the SCs subject to AMR for the SGTS in Table 2.3.3-6 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SCs from Table 2.3.3-6 to verify that the applicant identified the SCs subject to an AMR. The staff also sampled SCs that were within the scope of license renewal, but not subject to AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on a qualified life or specified time period.

To help ensure that those portions of the SGTS identified as not within the scope of license renewal did not perform any intended functions, the staff issued an RAI on the basis of the applicable information in the FSARs and LRA. The staff noted that Section 2.3.3.6 of the LRA presents a summary description of the system functions, evaluation boundary drawings highlight the evaluation boundaries of the SGTS, and Table 2.3.3-6 tabulates components within the scope of license renewal and subject to an AMR. The corresponding drawings for this system in the FSAR, however, show additional components that were not listed in Table 2.3.3-6 of the LRA.

In RAI 2.3.3-SGTS-1 and RAI 2.3.3-SGTS-2, the staff requested specific information concerning the exclusion of the following components from the scope of license renewal and/or from an AMR:

(1) differential pressure indicator and associated piping (Unit 1, Filter Assembly D001B, HL-16020, SGTS Sh. 1)

(2) temperature element and associated piping (Unit 1, Filter Assembly D001B, HL-16020, SGTS Sh. 1 @G4)

(3) flow switch (FS N011A) and open valves (N011A-RV1, N011A-RV2) and associated piping (3/8 inch diameter piping) (Unit 1, HL-16174, SGTS Sh. 2 @ C7)

(4) filter housing with pre-filter, high-efficiency particulate air (HEPA) and carbon filters (Unit 1, Filter Assemblies D001A and D001B, HL-16020 @ (C2, C3, C4, and C5) and (G2, G3, G4, and G5))

(5) bird screen or wire mesh, if provided as a protective cover for exhaust stack (Unit 1, HL-16174, SGTS Sh. 2 @ C10)

(6) guillotine damper housing (Unit 2, Filter Assemblies D001A and D001B, HL-26078 @ C4 and G4)

(7) filter housing with pre-filter, HEPA and carbon filters (Unit 2, Filter Assemblies D001A and D001B, HL-26078 @ (C2, C3, C4, and C5) and (G2, G3, G4, and G5))

(8) “buried pipe” (Unit 2, HL-26078 @ G10)

(9) bird screen or wire mesh, if provided as a protective cover for an exhaust stack (Unit 2, HL-26078 @ C11)

(10) outside air probe tubing (Unit 1, HL-16174, SGTS Sh. 2 @ A9, B9, and C9)

(11) fan housing (Unit 1, HL-16174, SGTS Sh. 2 @ C5 and F5)

(12) outside air probe tubing (Unit 2, HL-26078 @ A9, B9, and C9)

(13) fan housing (Unit 2, HL-26078 @ C4 and G4)

In a letter dated August 29, 2000, the applicant provided the following responses:

(1) differential pressure indicators are active components (NEI 95-10 Rev., Appendix B, Item 76) and therefore, no AMR is required for the differential pressure indicators shown in HL-16020; associated tubing is made of copper and is screened as piping, and Table 2.3.3-6 includes this component

(2) temperature element was screened as thermowell, which is made of stainless steel, and Table 2.3.3-6 includes this component; associated tubing is made of copper and is screened as piping, and Table 2.3.3-6 includes this component as well

(3) flow switches are active components (NEI 95-10 Rev. 0, Appendix B, Item 84) and therefore, no AMR is required for the flow switches shown in HL-16174; valves and associated piping made of carbon steel are included in Table 2.3.3-6

(4) filter housing (Unit 1) on HL-16020 is made of galvanized steel; an AMR was performed on the filter housing and this item is included in Table 2.3.3-6; pre-filter, HEPA filter, and carbon filter are in scope and are therefore, consumables not subject to AMR (these items were inadvertently left out from the boundary drawing HL-16020)

(5) bird screen (Unit 1) is included in the exhaust stack as miscellaneous steel (see Table 2.4.11-1)

(6) dampers are active components (NEI 95-10, Rev.0, Appendix B, Item 155) and therefore, no AMR is required for the guillotine damper housing

(7) filter housing (Unit 2) on HL-26078 is made of galvanized steel; an AMR was performed on the filter housing and this item is included in Table 2.3.3-6;prefilter, HEPA filter, and carbon filter are in scope and are therefore, consumables not subject to AMR (these items were inadvertently left out from the boundary HL-26078)

(8) buried piping is made of carbon steel and included in Table 2.3.3-6

(9) bird screen (Unit 2) is included in the exhaust stack as miscellaneous steel

(10) outside air probe tubing (Unit 1) is made of copper and screened as piping, and Table 2.3.3-6 includes this component

(11) NEI 95-10, Rev. 0, Appendix B, Item 163, designates ventilation fans (Unit 1) as active components and therefore, no AMR is required for the fan housing shown in HL-16174

(12) outside air probe tubing (Unit 2) is made of copper and screened as piping, and Table 2.3.3-6 includes this component

(13) NEI 95-10, Rev. 0, Appendix B, Item 163, designates ventilation fans (Unit 2) as active components and therefore, no AMR is required for the fan housings shown in HL-26078

The staff reviewed the applicant's responses concerning the associated tubing for differential pressure indicators, temperature element and its associated tubing, valves and associated piping for flow switches, filter housing (Units 1 and 2) for carbon and HEPA filters, bird screen (Units 1 and 2), buried piping, and outside air probe tubing (Units 1 and 2), and found them acceptable, since these component commodity groupings were within the scope of license renewal and subject to an AMR, in accordance with the applicable requirements of 10 CFR 54.21(a)(1), 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3).

In its responses to RAI 2.3.3-SGTS-1 and RAI 2.3.3-SGTS-2, the applicant stated that differential pressure indicators, guillotine damper housings, and fan housings in the SGTS are not subject to an AMR based on NEI 95-10, Appendix B guidance. The staff agrees that differential pressure indicators are considered components with an active function and, therefore, are not subject to an AMR. However, the staff questioned whether it was appropriate for the applicant to exclude guillotine damper housings and fan housings from an AMR. During a telephone conference (telecon) on October 31, 2000, the staff asked the applicant to provide justification for why the housings for the guillotine dampers and fans should be excluded from an AMR.

In response to staff concerns regarding the exclusion from an AMR of the housings for components such as fans, dampers, and heating and cooling coils, the applicant provided, by an e-mail dated November 6, 2000, a paper titled "Active Assemblies Used in License Renewal."

The staff has reviewed this paper and finds that the applicant's basis for excluding fan, damper, and heating and cooling coil housings is not consistent with the license renewal rule, the Statements of Consideration (SOC) accompanying the license renewal rule in 10 CFR Part 54, and the staff's review guidance.

10 CFR 54.21(a)(1) provides that those components that perform their intended functions without moving parts and without a change in configuration or properties (10 CFR 54.21(a)(1)(i)) and that are not subject to replacement based on qualified life or specified time period (10 CFR 54.21(a)(1)(ii)) are subject to an AMR. Such components are commonly considered as "long-lived" and as performing a passive function. 10 CFR 54.21(a)(1)(i) states that "structures and components [with passive functions] include, but are not limited to,... pump casings, valve bodies ... " and lists other components that perform passive functions. The examples cited in the rule illustrate components with significant passive functions.

The SOC, in Section III.f.i(a), further explains that major components may have active functions, passive functions, or both, and cites pumps and valves as examples (SOC Section III.f.i.(a)). Pumps and valves have moving parts, but the Commission concluded that the pressure-retaining function performed by the pump casing and the valve body were important enough to warrant an AMR. The SOC further explains that the Commission does not limit the consideration of pressure boundaries to reactor coolant pressure boundary. The exclusion regarding components is focused on active functions rather than on the exclusion of the entire component, while the AMR applies to the passive function of the component. On this basis, the staff concludes that fans, dampers, and heating and cooling coils may include significant passive pressure-retaining and structural support functions.

Section 2.2.III.A of the draft SRP-LR, September 1997, states that "...some functions of "active" components may meet the criteria of the "passive" description. For example, although a pump or a valve has some moving parts, a pump casing or valve body performs a pressure retaining function without moving parts. A pump casing or a valve body meets this description and would therefore be considered for an aging management review." It is clear by this passage, and by the examples provided of pumps and valves, that the passive functions of components are subject to an AMR.

In Section 2.1.1 of the LRA, the applicant states that the specific method used to identify in-scope functions and to screen the SSCs required to perform the in-scope functions was developed considering the guidance provided by NEI 95-10, Revision 0, "Industry Guideline on Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule," among other regulatory and guidance documents. Appendix B of NEI 95-10 provides a list of components and their active/passive functions. Item numbers 155 and 163 identify dampers and ventilation fans, respectively. Each of these components is identified in the appendix as performing an active function. The staff notes that the appendix, though it specifically identifies the dampers and ventilation fans, does not address housings for these components.

On the basis of the information in the regulation, the SOC, and guidance provided in the SRP-LR, the staff concludes that the housings for fans, dampers, and heating and cooling coils contribute to the performance of the intended function of fans, dampers, and heating and cooling coils without moving parts and without a change in configuration or properties, and thus are subject to an AMR. This issue also affects the scope of components with passive functions for the control building HVAC, outside structures HVAC, and reactor building HVAC systems, which are discussed in Section 2.3.4.2 of this SER.

Therefore, based on the above staff positions, the staff requests that the applicant identify the passive functions for those fans, dampers, and heating and cooling coils that are within the scope of license renewal. For those passive functions, the applicant should identify any aging effects associated with the components and provide an AMP to manage the aging. This is part of Open Item 2.3.3.2-2.

The applicant also agreed to clarify the function of the guillotine damper regarding whether this damper is safety-related and included in the scope of license renewal and subject to an AMR. This is part of Open Item 2.3.3.2-2.

The staff reviewed Section 2.3.3.6 of the LRA, supporting information in the FSAR, the applicant's responses to the staff's RAIs, and other information submitted for staff review. In addition, the staff sampled several components in the previously mentioned evaluation boundary drawings of the LRA to determine whether the applicant properly identified the components within the scope of license renewal and subject to an AMR.

On the basis of this review, pending satisfactory resolution of Open Item 2.3.3.2-2 above, the staff has reasonable assurance that the applicant has adequately identified the SGTS components within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4, and 10 CFR 54.21.

Standby Liquid Control System

In RAI 2.3.3-SLCS-1, the staff indicated that Table 2.3.3-1 of the LRA identifies the pressure boundary as the only intended function for the components supporting the standby liquid control system (SLCS), per 10 CFR 54.4(a)(1)(i). The staff, however, believes that the components have additional intended functions as delineated in 10 CFR 54.4(a)(1)(ii) and (iii), namely, the capability to shutdown the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure, respectively. It was not clear in the LRA whether these functions were considered to be intended functions of the components supporting the SLCS. The staff, therefore, requested clarification from the applicant. In response, the applicant explained that its scoping process identified functions, and applied all the Part 54 criteria, including 10 CFR 54.4(a)(1)(i), (ii) and (iii), to determine if the functions were intended functions which should be in scope. Portions of the SLCS were determined to be in scope because they met one or more of the criteria in 10 CFR Part 54.4. It was clarified that Table 2.2-1 of the LRA presents the scoping results. Function numbers C41-01 and C41-03, which are defined as reactivity control and SLCS testing, respectively, are in scope. On the basis of the applicant's response to this RAI, the staff concludes that the applicant has clarified the intended functions of of SLCS.

In RAI 2.3.3-SLCS-2, the staff questioned the basis for not including the SLCS poison standpipe/sparger within the scope of license renewal or from including it as subject to an AMR. The staff stated in the RAI that although the standpipe/sparger may not perform the pressure boundary function, it does perform other intended functions, such as the capability to shutdown the reactor and maintain it in a safe shutdown condition, and the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure. The staff further stated that aging effects, such as blockage of the standpipe/sparger perforations to prevent the injection of liquid poison solution and/or cracking of the component itself, may degrade its function to assure good mixing and dispersion of the poison inside the reactor vessel. The staff, therefore, requested the applicant to submit an AMR, or to present a justification for the exclusion of the SLCS poison standpipe/ sparger from an AMR. The applicant stated in its response that the SLCS sparger was evaluated by the Boiling Water Reactor Vessel Internal Program (BWRVIP). The initial safety assessment is documented in BWRVIP-06, "Safety Assessment of BWR Reactor Internals," in which it was concluded that failure of the sparger due to cracking " has no performance or safety consequence." The NRC issued a safety evaluation for BWRVIP-06 on September 15, 1998. BWRVIP later performed a more detailed assessment of the SLCS piping and sparger to determine the need for any inspections. The results are documented in BWRVIP-27, "BWR Standby Liquid Control System/Core Plate ΔP Inspection and Flaw Evaluation Guidelines." This assessment, like BWRVIP-06, considered all modes of degradation and identified the actions necessary to assure safe operation. Boron mixing was specifically addressed in Section 2.2.1 of BWRVIP-27. The conclusion was that cracking of the sparger would not prevent the poison from mixing and shutting down the reactor. BWRVIP-27 was reviewed and approved for generic use by the NRC in the SERs for both the current term (May 27, 1999) and for the license renewal term (December 20, 1999). Furthermore, the applicant stated that based on the materials of construction and the environment, plugging of the sparger due to corrosion of the sparger is not a plausible aging effect. The applicant also stated that if crud from the bottom head region were to accumulate, the pressure associated with SLCS injection would dislodge any crud and flow would be assured. Therefore, an aging management activity is not

warranted. On the basis of the applicant's response to this RAI, the staff concludes that the standpipe/sparger does not perform an intended function, and therefore is not subject to an AMR.

On the basis of the staff's review of the information provided in the LRA, and described in Section 2.3.3.1 of this SER, for the standby liquid control system, the staff concludes that the applicant has properly identified the components associated with the standby liquid control system within the scope of license renewal, as required by 10 CFR Part 54.4(a), and has properly identified the components subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

2.3.3.3 Conclusions

On the basis of the staff's review of the information presented in Section 2.3.3 of the LRA, the supporting information in the Plant Hatch FSAR, the applicant's response to the staff's RAIs, and the additional information provided in telephone conversations between the applicant and the staff, pending satisfactory resolution of Open Items 2.3.3.2-1 and 2.3.3.2-2, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the ESF systems that are within the scope of license renewal and subject to an AMR, in accordance with the requirements of 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.3.4 Auxiliary Systems

The applicant described the auxiliary systems that are within the scope of license renewal and subject to an AMR in the following sections of the LRA: 2.3.4.1, "Control Rod Drive System;" 2.3.4.2, "Refueling Equipment System;" 2.3.4.3, "Insulation System;" 2.3.4.4, "Access Doors System;" 2.3.4.5, "Condensate Transfer and Storage System;" 2.3.4.6, "Sampling System;" 2.3.4.7, "Plant Service Water System;" 2.3.4.8, "Reactor Building Closed Cooling Water System;" 2.3.4.9, "Instrument Air System;" 2.3.4.10, "Primary Containment Chilled Water System;" 2.3.4.11, "Drywell Pneumatics System;" 2.3.4.12, "Emergency Diesel Generators System;" 2.3.4.13, "Cranes, Hoists, and Elevators System;" 2.3.4.14, "Tornado Vents System;" 2.3.4.15, "Reactor Building Heating, Ventilation, and Air Conditioning (HVAC) System;" 2.3.4.16, "Traveling Water Screens/Trash Racks System;" 2.3.4.17, "Outside Structures HVAC System;" 2.3.4.18, "Fire Protection System;" 2.3.4.19, "Fuel Oil System;" and 2.3.4.20, "Control Building HVAC System." For these systems, the applicant identified the in-scope structures and components that are subject to an AMR. 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 within the scope of license renewal, as required by 10 CFR 54.4, and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.3.4.1 Summary of Technical Information in the Application

<u>Access Doors System</u>

The secondary containment access doors are designed to provide access for personnel and equipment to the reactor building. In Section 2.3.4.4, of the LRA, the applicant described the intended functions and listed the components of the system that are subject to an AMR. The applicant described its process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, and Section 2.1.3, of the LRA.

In Section 2.3.4.4 of the LRA, the applicant stated that the secondary containment provides, in conjunction with the primary containment and other engineering safeguards, the capability to limit the release to the environment of radioactive materials so that the offsite dose from a postulated design basis accident will be below the guideline values of 10 CFR 100.

The initial scoping, performed by the applicant and based on system functions, has determined the following intended function for the access doors system to be within the scope of license renewal.

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

The associated structural steel is identified in Table 2.3.4-4 of the LRA as being subject to an AMR. The functions for the structural steel are missile barrier and fission product barrier.

<u>Condensate Transfer & Storage System</u>

The condensate transfer and storage system provides the plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type services. In Section 2.3.4.5, “Condensate Transfer & Storage System,” of the LRA, the applicant described the intended functions and listed the components of the system that are subject to an AMR. The applicant described their process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, “Scoping,” and Section 2.1.3, “Civil/Mechanical Component Screening,” of the LRA.

In Section 2.3.4.5, “Condensate Transfer & Storage System,” of the LRA, the applicant described that the purpose of the condensate transfer and storage system is to provide the plant system makeup, receive reject flow, and provide condensate for any continuous service needs and intermittent batch-type services. The total stored design quantity is based on the demand requirements during refueling for filling the dryer separator pool and the reactor well. A 500,000 gallon condensate storage tank (CST) supplies the various unit requirements. The Unit 1 tank is constructed of aluminum and the unit 2 tank of stainless steel. The system also consists of two condensate transfer pumps and associated piping and valves. The CST provides the preferred supply to the high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) systems. All other suctions are located above suction lines for these systems to provide a 100,000 gallon reserve.

The initial scooping, performed by the applicant and based on the functions, has determined the following intended functions for the condensate transfer and storage system to be within the scope of license renewal.

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

The associated piping, valve bodies, bolting, and tanks are identified in Table 2.3.4-5 of the LRA as within the scope of license renewal and subject to an AMR. The component function for these components is pressure boundary.

Control Building HVAC

In LRA Section 2.3.4.20, the applicant identified portions of the Control Building HVAC System and the components within the scope of license renewal and subject to an AMR. The applicant stated in Section 2.3.4.20 of the LRA that additional information for the system is provided in Section 9.7 of the FSAR for Unit 2. The system scoping is shown in control building evaluation boundary drawings HL-16040, Rev. A and HL-11609 for Unit 1, and HL-16042, Rev. A and HL-26116, Rev. A for Units 1 and 2.

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

Plant Hatch Unit 1

The control building is served by HVAC systems. In the general area, outside air is supplied by three 50-percent-capacity fans. The air is filtered and distributed by ductwork in proportion to the equipment and lighting loads in these areas. The exhaust system is split between Units 1 and 2. Three 50-percent-capacity Unit 1 fans and two 100-percent-capacity Unit 2 fans exhaust air to the Units 1 and 2 reactor vent plenums.

The following areas are fully air conditioned with direct expansion water-cooled air-conditioning units: main control room (MCR), computer room, water sampling room, chemical laboratory and health physics area, cold lab, shift supervisor's area, LPCI inverter room, and Units 1 and 2 Vital AC rooms. The battery rooms have exhaust fans and heaters. The cable spreading room has a separate ventilation system. The details of HVAC systems serving these areas are described in Section 10.9.3.6 of the FSAR for Unit 1.

Plant Hatch Units 1 and 2

The heating, ventilation, and air-conditioning (HVAC) system is shared by Unit 1 and Unit 2. The MCR habitability systems are designed to provide safety and comfort for operating personnel during normal operations and during postulated accident conditions. These habitability systems for the MCR include radiation shielding, charcoal and other filter systems, HVAC, sanitary facilities, and fire protection. A discussion of the MCR systems that control the climatic conditions existing within the MCR is provided in Section 9.4.1 of the Unit 2 FSAR.

Previous analyses demonstrate that the loss of coolant accident (LOCA) is the limiting event for radiological exposures to operators in the MCR. The pressurization mode of operation of the MCR environmental control system (MCRECS) is provided to minimize the amount of

radioactivity entering the MCR following an accident. The MCR atmosphere is recirculated through the MCRECS emergency filters with sufficient outside air being drawn in through the normal intake to maintain the MCR at a positive pressure of >0.1-in. water gauge (WG) relative to the surrounding turbine building. The MCR is designed to maintain its temperature below 79 °F with relative humidity of 75%. Fire protection for the MCR is discussed in Section 9.5.1 of the FSAR for Unit 2. Since no gaseous chlorine is used or stored on site, the chlorine accident was not evaluated for the MCR.

The MCRECS is discussed in Section 9.4.1 of the FSAR for Unit 2. The Unit 1 and Unit 2 MCRs are housed in a shared facility. The habitability systems are designed to serve the Unit 1 and Unit 2 combined control rooms. The principal equipment in the system includes: (1) three 50-percent-capacity air-handling units (AHUs) with cooling coils and fans; (2) three 50-percent-capacity condensing units, each consisting of refrigerant compressor, condenser, and associated controls which service the AHU cooling coils; (3) two 100-percent-capacity exhaust air fans; (4) two trains of high-efficiency air filtration units consisting of a profiler, a high-efficiency particulate air (HEPA) filter, an electric carbon drying heater, a carbon absorber, a second HEPA filter for emergency treatment of recirculated air or outside supply air, and two filtration unit booster fans, one for each filtration unit. The MCRECS is designed with sufficient redundancy and separation of active components to provide reliable operation under normal conditions and to ensure operation under emergency conditions. Where redundancy does not exist (e.g., restroom exhaust dampers and exhaust fan isolation dampers), the system is normally operated such that at least one isolation barrier is normally closed. In the case of the restrooms, the doors provide that barrier. Upon verification that the exhaust dampers have closed for the pressurization mode, access to the restrooms is allowed via these doors. In the case of the exhaust fan isolation dampers, the fans are normally not operated, and the dampers are normally closed. The MCRECS normal operation and accident condition modes, and associated instrumentation application are described in Section 6.4 of the FSAR for Unit 2. The control building HVAC systems are described in Section 9.4.7 of the FSAR for Unit 2.

In Section 2.3.4.20 of the LRA, the applicant identified the following intended functions that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3):

- Control Room Habitability (Z41-02)
- Control Building Environmental Support (Z41-03)

On the basis of the functions identified above, the applicant determined that all safety-related components (electrical, mechanical, and instrument) are within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the system that are within the scope of license renewal in control building evaluation boundary drawings HL-16040, Rev. A and HL-11609, Rev. A for Unit 1, and HL-16042, Rev. A and HL-26116, Rev. A for Units 1 and 2. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the mechanical components and component types within the license renewal boundaries that are subject to an AMR and identified their ~~intended~~ functions. The applicant provided this list in Table 2.3.4-20 of the LRA.

The applicant identified the following 22 device types as within the scope of license renewal and subject to an AMR:

- accumulator air valve (carbon steel)
- accumulator piping (carbon steel)
- accumulator tanks (stainless steel)
- bolting (carbon steel)
- duct gasket (fibers, non-asbestos, synthetic; elastomers, other)
- duct heater (aluminum)
- duct silencer (galvanized steel)
- ductwork (carbon steel)
- ductwork (galvanized steel)
- ductwork flex connector (fibers, non-asbestos synthetic; elastomers, other)
- filter housing (galvanized steel)
- flow element (stainless steel)
- instrument piping (copper alloy)
- instrument piping (stainless steel)
- louver (carbon steel)
- piping (stainless steel)
- radiation element (stainless steel)
- temperature sensor (stainless steel)
- tubing (copper)
- valve bodies (carbon steel)
- valve bodies (copper alloy)
- valve bodies (stainless steel).

In Table 2.3.4-20, the applicant further noted that the pressure boundary function is the only applicable function associated with components that are subject to an AMR.

<u>Control Rod Drive (CRD) System</u>

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

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

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

System Intended Functions

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

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

Component Intended Function

- Fission product barrier
- Pressure boundary

The component groups requiring an AMR, as identified in the LRA, are as follows: accumulator, bolting, piping, rupture disc, and valve bodies. [See request for additional information (RAI) 2.3.4-CRD-1]

Cranes, Hoists and Elevators System

In LRA Section 2.3.4.13 of the LRA, the applicant provides a description of the cranes, hoists and elevators system. The reactor building crane is the only component for this system that is within the scope of license renewal. The purpose of the reactor building crane is to provide the capability for moving major components for refueling operations and maintenance. The Unit 1 reactor building crane provides service to both Unit 1 and Unit 2. It has the capability to move loads up to 125 tons with the main hook. This capability includes the handling of shield plugs, reactor vessel heads, drywell heads, steam dryers, steam separators, and the spent-fuel shipping casks. The reactor building crane main and auxiliary hooks have an electrical interlock system to prevent their potential movement over spent fuel.

Although the reactor building crane provides the ability to handle the large loads associated with refueling operations and maintenance in the reactor building, the only intended function for the reactor building crane is that the load bearing components must maintain their structural integrity.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the reactor building crane load bearing components as the passive, long-lived portion of the system requiring an AMR. The applicant identified structural steel as the only component type subject to an AMR, and structural support is the function for this component.

Drywell Pneumatics System

The drywell pneumatic system supplies motive gas to equipment inside the drywell. In Section 2.3.4.11of the LRA, the applicant described the intended functions and listed the components of the system that are subject to an AMR. The applicant described its process for identifying the mechanical components within the scope of license renewal in Section 2.1.2 and Section 2.1.3, of the LRA.

In Section 2.3.4.11 of the LRA, the applicant described the purpose of the drywell pneumatic system which is to supply motive gas to the following equipment inside the drywell: reactor recirculation system sample line isolation valve, reactor pressure vessel (RPV) head vent valve, core spray (CS) system injection testable check valves and bypass valves, primary containment chilled water system control valves, residual heat removal (RHR) system low pressure coolant injection (LPCI) check valves and bypass valves, and nuclear boiler system safety relief valves (SRVs), and main steam isolation valves (MSIVs). A major portion of the drywell pneumatic system is primarily obsolete and not currently used. The control air is supplied from the nitrogen makeup system or instrument air. The system components still exist in the plant but are isolated by valve alignment or the lines are physically cut and capped. The drywell pneumatic system receives motive gas from the Unit 1 or Unit 2 nitrogen storage tanks, the instrument air system, or the emergency nitrogen hookup stations. The system includes an air receiver, particulate filters, flow sensing elements, and various process piping, valves, and regulators. Normally all system equipment upstream of the receiver tank is isolated, and system pressure is maintained by the nitrogen back-up supply with alternate supply through the instrument air supply system. Under emergency condition specific components in the drywell will be supplied control air from emergency nitrogen bottles.

The initial scoping, performed by the applicant and based on system functions, has determined the following intended function for the drywell pneumatic system to be within the scope of license renewal

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

The associated piping, valve bodies, bolting, filter housings, flexible hose, flanges, and tubing are identified in Table 2.3.4-11 of the LRA as within the scope of license renewal and subject to an AMR. The component function for all the above components is pressure boundary.

Emergency Diesel Generators System

The Hatch emergency diesel generators system is designed to provide onsite emergency backup power in the event of a loss of offsite power. In the LRA Section 2.3.4.12, “Emergency Diesel Generators System,” the applicant describes the intended functions and lists the

components of the system that are subject to an AMR. The applicant described their process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, “Scoping,” and Section 2.1.3, “Civil/Mechanical Component Screening,” of the LRA.

In Section 2.3.4.12 of the LRA, the applicant described the purpose of the diesel generators is to provide emergency backup power to 4160 VAC emergency buses E, F, and G in the event of a loss of offsite power. The diesel generators are designed to reach rated speed and voltage within 12 seconds after receiving a start signal. This allows operation of emergency equipment powered from these buses to perform their required function to safely shutdown the plant within the required time. The emergency diesel generators (EDGs) provide a highly reliable source of standby, onsite, ac power. There are five diesel generators supplying standby power to emergency buses. Diesel generator 1B is shared between Units 1 and 2 and has a selector switch with “Unit 1 control” and “Unit 2 control” positions, depending on whether it is supplying bus 1F or 2F.

The initial scoping, performed by the applicant and based on the functions, has determined the following intended functions for the emergency diesel generators system to be within the scope of license renewal.

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

The associated piping, valve bodies, filter housing, flex hose, expansion tank, flexible connector, tanks, and restricting orifice are identified in Table 2.3.4-12 of the LRA as being subject to an AMR. The intended function for all these components is pressure boundary.

<u>Fire Protection</u>

In Section 2.3.4.18, “Fire Protection System [X43],” of the Plant Hatch LRA, the applicant described the components of the fire protection system that are within the scope of license renewal and subject to an AMR. The staff reviewed this section of the LRA to determine whether there is reasonable assurance that all SSCs have been identified as being within the scope of license renewal, as required by 10 CFR Part 54.4(a), and that all components subject to an AMR have been identified, as required by 10 CFR Part 54.21(a)(1).

By letter dated August 29, 2000, the applicant responded to the staff’s requests for additional information (RAIs) regarding the fire protection systems and components. In addition, the applicant provided additional information for the fire protection system by telephone conferences which are documented in summaries dated, September 12 and 28, 2000, October 1, 2000 (by email), October 13, 2000 (by email), and November 15, 2000.

Structures and mechanical systems which are relied upon to perform or support performance of a function that demonstrates compliance with the Commission’s regulations described in 10 CFR 54.4(a)(3) are within the scope of license renewal. 10 CFR 54.4(a)(3) requires that all systems, structures, and components (SSC’s) relied upon in safety analyses or plant evaluation to demonstrate compliance with the Commission’s regulations in 10 CFR 50.48, be included within the scope of license renewal. 10 CFR 50.48 requires that the applicant implement and

maintain a fire protection program. The fire protection system is relied upon to meet the requirements of 10 CFR 50.48. At Plant Hatch, the fire hazards analysis (FHA) is the focal point which contains information on how regulatory commitments are met through analyses and plant evaluations.

The purpose of the fire protection program at Hatch is to assure, through defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occuring. The defense-in-depth principle is aimed at achieving an adequate balance in these areas along with:

- preventing fires from starting,

- detecting fires quickly, rapidly suppressing fires that occur and limiting their damage, and

- designing plant safety systems so that a fire which starts in spite of the fire protection program and burns for a significant period of time will not prevent essential plant safety functions from being performed.

The initial scoping at Plant Hatch was performed on the basis of functions. The intended functions shown in LRA Section 2.3.4.18 are associated with the fire protection system. The fire protection intended functions within the scope of license renewal include:

- X43-01 - Cardox Fire Suppression for EDGs
- X43-02 - Halon Suppression - Remote Shutdown Panel (Unit 2)
- X43-04 - Plant Wide Fire Suppression With Water
- X43-06 - Fire Detection
- X43-07 - Penseals and Fire Barriers for Preventing Fire Propagation
- X43-08 - Manual Carbon Dioxide Fire Protection
- X43-10 - Cardox Fire Suppression for the Computer Room

In Table 2.3.4-18 of the LRA, the applicant identified the components supporting the fire protection system [X43] intended functions that are within the scope of license renewal and subject to an AMR. The fire protection components that provide only a pressure boundary function that are identified in able 2.3.4-18 are: bolting, fire hydrants, fittings, fusible material, pilot valves, pipe line trainers, piping, pump casings, sprinkler head bulbs, sprinkler head links, strainer basket, trainers, tanks, tubing, tubing fittings, and valve bodies. In response to Part 7 of RAI-2.3.4-FPS-3, the applicant clarified in that the passive, long-lived components for hose stations are included in able 2.3.4-18 as piping, valves, and nozzles.

The fire protection components that provide only a fire barrier function that are identified in Table 2.3.4-18 are: fire doors, Kaowool & hold-down straps, and penetration seals.

Fire protection components that provide only a flow restriction function are nozzles. Restricting rifices provide both a pressure boundary and flow restriction function. The sprinkler eads provide a flow direction, pressure boundary, and flow restriction function. The ank insulation provides an environmental control function.

Fuel Oil System

The fuel oil system is designed to receive, store, and supply fuel oil to the diesel generator system. In Section 2.3.4.19, "Fuel Oil System," of the LRA, the applicant described the intended functions of the system and listed the components that are subject to an AMR. The applicant described their process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, "Scoping," of the LRA and subject to an AMR in Section 2.1.3, "Civil/Mechanical Component Screening," of the LRA.

In Section 2.3.4.19 of the LRA, the applicant described the function of the fuel oil system is to receive, store, and supply fuel oil to the diesel generator system. Diesel engine fuel for Hatch Units 1 and 2 is stored in five interconnected buried tanks. Diesel fuel is transferred to the engine day tanks using dedicated, redundant transfer pumps and piping. The diesel fuel storage tanks are filled by gravity from a truck connection through a common header. Two of the buried tanks are dedicated to each of the Unit 1 and Unit 2 diesel generators. The remaining tank is used to supply the swing diesel (1B) to serve either Unit 1 or Unit 2. The fuel oil system transfer pumps operate continuously on demand from the day tank level controllers. tank levels are monitored and alarmed (low level) in the main control room (MCR).

The initial scooping, performed by the applicant and based on the functions, has determined the following intended functions for the fuel oil system to be within the scope of license renewal.

Y52-01 – Emergency Diesel Generator (EDG) Fuel Oil Supply: The EDG fuel oil system provides a 7 day supply of fuel oil to the diesels in the event of a loss of offsite power (LOSP). The availability of the storage tanks is needed for an extended duration LOSP, which is a risk-significant event. The components associated with this function include the fuel oil supply piping, instrumentation, and valves in the piping from the fuel oil pumps to the EDGs.

The associated piping, valve bodies, bolting, discharge head, flex hose, manway shell, pump, strainer basket, and tank are listed in Table 2.3.4-19 of the LRA as being subject to an AMR. The component functions for the manway shell and strainer basket are shelter/protection and the function for the piping, valve bodies, bolting, discharge head, flex hose, pump, and tank is the pressure boundary.

Instrument Air System

The instrument air system provides dried and filtered air to all of the air operated instruments and valves throughout the entire plant (with the exception of equipment inside the drywell). In Section 2.3.4.9, "Instrument Air System," of the LRA, the applicant described the intended functions and listed the components of the system that are subject to an AMR. The applicant described their process for identifying the mechanical components within the scope of license renewal in Section 2.1.2, "Scoping," and Section 2.1.3, "Civil/Mechanical Component Screening," of the LRA.

In Section 2.3.4.9 of the LRA, the applicant described the purpose of the instrument air system is to provide dried and filtered air to all of the air operated instruments and valves throughout the entire plant (with the exception of equipment inside the drywell). The instrument air system is divided into the following two subsystems:

- Noninterruptible system provides instrument air for the operation of certain emergency system components.

- Interruptible system provides instrument air to all other components not supplied by the noninterruptible system.

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

The initial scooping, performed by the applicant and based on the functions, has determined the following intended functions for the instrument air system to be within the scope of license renewal.

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

The associated piping, valve bodies, bolting, hose, pressure regulator and tubing are identified in Table 2.3.4-9 of the LRA as within the scope of license renewal and subject to an AMR. The component function for these components is pressure boundary.

<u>Insulation</u>

The intended function for insulation is to retain heat in process piping and equipment in various locations outside the drywell, prevent moisture from condensing on cold surfaces, protect equipment and personnel from high temperatures, prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage. The application further states that heat tracing with insulation is required for the standby liquid control system to operate in order to meet ATWS requirements. Insulation is also credited in heat load calculations for safety-related rooms. Failure of piping insulation in safety-related rooms could allow the heat load of the room to exceed the capability of the HVAC system, thus exceeding the design temperature of the room. The insulation intended function can be more concisely stated as follows: to minimize heat transfer between process piping and the environment and to protect heat tracing on piping.

The applicant provided seven drawings for Unit 1 and five drawings for Unit 2 that had intended function designations marked on the drawing to indicate piping insulation that is within the

scope of license renewal. These drawings are DL-11001, DL-11004, HL-11033 (sheet 1), HL-11600, HL-16061, HL-16332, HL-16334, HL-21033, HL-21039, HL-26009, HL-26020, and HL-26023. The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified insulation in various areas outside the drywell as the passive, long-lived portion of the system which requires an AMR. The following six component types were identified as being subject to an AMR: aluminum jacket, insulation, insulation bolting (galvanized steel), insulation bolting (stainless steel), stainless steel jacket, and wire. The applicant identified environmental control as the function for these components.

Outside Structures HVAC

In LRA Section 2.3.4.17, the applicant identified portions of the Outside Structures HVAC System and the components within the scope of license renewal and subject to an AMR. The applicant stated in Section 2.3.4.17 of the LRA that additional information for the outside structures HVAC system is provided in Sections 9.4.5 and 9.4.10 of the FSAR for Unit 2. The system scoping is shown in outside structures HVAC system evaluation boundary drawing HL-44073, Rev. A.

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

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

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

In Section 2.3.4.17 of the LRA, the applicant identified the following intended functions for the outside structures HVAC system that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3):

- Intake structure environmental control
- EDG building environmental control
- EDG building battery room H2 control
- EDG switchgear room heating and ventilation
- EDG building oil storage room ventilation

On the basis of the functions identified above, the applicant determined that all outside structures HVAC system safety-related components (electrical, mechanical, and instrument) are within the scope of license renewal. The applicant described its process for identifying the mechanical components subject to AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the outside structures HVAC system that are within the scope of license renewal in evaluation boundary drawing HL-44073, Rev. A. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the mechanical components and component types within the license renewal boundaries that are subject to an AMR and identified their functions. The applicant provided this list in Table 2.3.4-17 of the LRA.

The applicant identified the following five device types that are identified as within the scope of license renewal and subject to an AMR:

- bolting (carbon steel)
- bolting (stainless steel)
- duct sleeve (carbon steel)
- flow element (stainless steel)
- tubing (copper)

In Table 2.3.4-17 of the LRA, the applicant further noted that the outside structures HVAC system pressure boundary function is the only applicable function associated with components of the outside structures HVAC system that are subject to an AMR.

<u>Plant Service Water</u>

The plant service water (PSW) system provides cooling water to safety-related and non-safety-related equipment during normal operating and shutdown conditions. The PSW also provides makeup water to the circulating water system heat exchangers and is available for spent fuel pool emergency makeup, fire fighting, and radwaste dilution. The PSW is described in Hatch FSAR Units 1 and 2, Sections 10.7 and 9.2.1, respectively.

The PSW system consists of four, one-third capacity vertical wetpit service water pumps andassociated piping and controls, which divides into two divisions. Each division supplies cooling water to one redundant train of safety-related equipment. Water for equipment cooling is taken from the river via the intake structure by these pumps and distributed by the two headers to different areas for use, including the diesel generator building, the reactor and control buildings and the refueling floor PSW supply.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1, "Scoping," of the LRA. On the basis of its methodology, the applicant identified the portions of the PSW system that are within the

scope of license renewal on evaluation boundary diagrams HL-11004, HL-11600, HL-11609, HL-21033, and HL-21035. The intended functions for the PSW system are essential mechanical/environmental support, turbine building isolation, and 1B emergency diesel generator cooling. The applicant compiled a list of mechanical components and component functions within the license renewal boundaries that are subject to an AMR. The applicant also identified their functions and listed them in Table 2.3.4-7 of the LRA. The applicant identified the following 14 component types as subject to an AMR: bolting, flexible connector, piping, pump bowl assembly, pump discharge column, pump discharge head, pump sub base, restricting orifices, sight glass body, strainer, strainer basket, thermowells, valve bodies, and venturi. The applicant stated that maintaining the pressure boundary, structural support, and debris protection are the applicable component functions.

Primary Containment Chilled Water

In Section 2.3.4.10 of the LRA, the applicant describes the primary containment chilled water system (Unit 2 only), (PCCW) system. The PCCW is designed to maintain the drywell area below a maximum volumetric average temperature of 150 °F dry bulb during normal operation by providing chilled water to the drywell fan coil units. The system consists of two chilled water recirculation pumps, two centrifugal chillers, a chemical addition tank, a chemical feed pump, and an expansion tank. Each chiller includes a refrigerant compressor, condenser, cooler, accessories, and controls. The chilled water recirculation pumps circulate chilled water through their respective chiller to the fan coil units. Service water from the reactor building service water system is circulated through the chiller condensers for cooling. Demineralized water provides a source of makeup water for the chilled water system. The expansion tank, chemical addition tank, and associated makeup water supply are shared with the reactor and radwaste building chilled water system.

The only intended function of the PCCW system is to maintain containment integrity. Specifically, the components that are within the scope of license renewal function to maintain primary containment integrity via a closed loop inside containment. The controls and instrumentation associated with primary containment isolation for this system function are evaluated as part of LRA Section 2.5.3.

The applicant provided one drawing (HL-26081) for Unit 2 that is highlighted to indicate piping from this system that is within the scope of license renewal. The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the piping system inside the drywell as the passive, long-lived portion of the system which requires an AMR. The following five component types were identified as being subject to an AMR: bolting, caps, piping, valve bodies, and thermowells. The applicant identified pressure boundary integrity as the function for these components.

Reactor Building Closed Cooling Water

The intended functions of the reactor building closed cooling water (RBCCW) system are to provide cooling water to certain auxiliary equipment located in the reactor building and to serve as a closed-cycle barrier between potentially radioactive systems and the plant service water system. The RBCCW system consists of three one-half capacity pumps, two full-capacity heat

exchangers, a surge tank, and a chemical addition system. Two of the RBCCW pumps are normally operating with the third pump on standby. The heat rejected by the RBCCW system to the heat exchanger is removed by the plant service water system. As discussed in Unit 1 FSAR Section 10.5 and Unit 2 FSAR Section 9.2.2, any possible leakage from the reactor auxiliary systems equipment will be into the RBCCW closed loop. The RBCCW system is monitored continuously for radioactivity by the process radiation monitoring system. Operation of the RBCCW system is not vital for safe shutdown of either Plant Hatch unit under normal or accident conditions. The RBCCW system is not required to be operable following a LOCA. Failure of any component of the RBCCW will not cause a significant release of radioactivity. The RBCCW system is only in the scope of license renewal to the extent that it provides containment integrity.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.2 of the LRA. On the basis of its methodology, the applicant identified the portions of the RBCCW system that are within the scope of license renewal on evaluation boundary diagrams HL-16009, HL-16066, HL-26003, and HL-26055. The applicant listed the mechanical components and component functions within the license renewal boundaries that are subject to an AMR. In Table 2.3.4-8 of the LRA, the applicant identified the following 9 component types as subject to an AMR: bolting, flexible connectors, flow element, heat exchanger shells, piping, relief valve base, temperature probe, thermowell, and valve bodies. The applicant identified maintaining the pressure boundary as the function for each component.

Reactor Building HVAC

In LRA Section 2.3.4.15, the applicant identified portions of the reactor building HVAC System and the components within the scope of License renewal and subject to an AMR. The applicant stated in Section 2.3.4.15 of the LRA that additional information for the reactor building HVAC system is provided in Sections 10.9 and 9.4.2 of the FSAR for Units 1 and 2, respectively. The system scoping is shown in evaluation boundary drawings HL-16005, Rev. A, HL-16014, Rev. A, and HL-16023, Rev. A for Unit 1, and HL-26067, Rev. A, HL-26072, Rev. A, and HL-26071, Rev. A for Unit 2.

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

In Section 2.3.4.15 of the LRA, the applicant identified the following component functions that relate to 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), and 10 CFR 54.4(a)(3):

- indirect radioactive release control
- essential mechanical/environmental support - ECCS room coolers
- essential mechanical/environmental support - RCIC and CRD room coolers

On the basis of the functions identified above, the applicant determined that all reactor building HVAC system safety-related components (electrical, mechanical, and instrument) are within the

scope of license renewal. The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.1.2 of the LRA. Based on this methodology, the applicant identified the portions of the reactor building HVAC system within the scope of license renewal in the system evaluation boundary drawings previously mentioned. Using the methodology described in Section 2.1.2 of the LRA, the applicant compiled a list of the mechanical components and component types within the license renewal boundaries that are subject to an AMR and identified their intended functions. The applicant provided this list in Table 2.3.4-15 of the LRA.

The applicant identified the following four device types that are identified as within the scope of license renewal and subject to an AMR:

- bolting (carbon steel)
- ductwork (galvanized steel)
- flow element (stainless steel)
- tubing (copper alloy)

In Table 2.3.4-15 of the LRA, the applicant further noted that the reactor building HVAC system fission product barrier and pressure boundary functions are the only applicable functions associated with components of the reactor building HVAC system that are subject to an AMR.

Refueling Equipment System

Section 2.3.4.2 of the LRA provides a description of the refueling equipment system (RE) and a list of structures and components that are subject to an AMR. The refueling platform equipment assembly is used for handling and transporting reactor core internals and service and handling equipment associated with the refueling operation. The refueling platform assembly consists of the refueling platform, fuel grapple, grapple headlight, and the hardware required to assemble these components into a workable unit. The applicant identified the following intended function for the RE system: to support fuel movement and control rod change out. The SCs that support this intended function include the refueling bridge, grapple, hoists, spent fuel servicing equipment, tools, and refueling interlocks. The applicant identified the structural integrity of the refueling platform as the passive, long-lived portion of the assembly that is within the scope of the license renewal.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the refueling platform structure as the passive, long-lived portion of the system which requires an AMR. The following four component types were identified as being subject to an AMR: anchors and bolts, miscellaneous steel, rivets, and structural steel. The applicant identified maintaining the structural integrity of the refueling platform as the function for these components.

Sampling System

The purpose of the primary containment hydrogen and oxygen analyzing (sampling) system is to provide a means of monitoring hydrogen and oxygen in the primary containment (drywell and torus). The system consists of two separate, redundant systems, each capable of analyzing

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

System Intended Functions

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

Component Intended Function

- Fission product barrier
- Pressure boundary

The component groups requiring an AMR, as identified in the LRA, are as follows: piping and valve bodies.

<u>Tornado Vents System</u>

In LRA Section 2.3.4.14 of the LRA, the applicant describes the tornado vents system (TV) system. The TV system is comprised of blowout panels designed to relieve excess pressure in various site structures. The TVs will blowout and vent the reactor and control building roofs under the following conditions:

- When wind velocity reaches 300 mph or greater.

- When the internal static pressure in the building is increased to 55 lb/ft^2.

- When the temperature reaches approximately 212° F.

The applicant identified pressure equalization as the intended function for the TV system. A rapid depressurization of air surrounding site structures can occur if a tornado funnel suddenly engulfs a structure. Venting, in this case, is accomplished by the blowout panels. The panels are designed to fail at a pressure lower than the safe internal building pressure capability, thus relieving excess pressure in all essential parts of such structures. The reactor building tornado relief vents are safety-related, and are required to maintain secondary containment during normal operation and during an earthquake. An inadvertent opening of the tornado vents could compromise secondary containment integrity. Tornado vents are relied upon to remain closed to prevent or mitigate the consequences of accidents that could result in potential offsite exposure. The opening of the vents during a tornado is a safety function to prevent collapse of safety-related structures.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified tornado vents as passive, long-lived structures requiring an AMR. The applicant identified the following component types as being subject to an AMR: screws, support frame, and tornado vent relief dome. The applicant identified structural support as the function for the screw and support frame components, and fission product barrier as the function for the tornado vent relief dome component.

Traveling Water Screens/Trash Racks System

The intended functions of the traveling water screens/trash racks system are intake structure trash removal and screen wash isolation. The traveling water screens prevent debris from entering the portion of the intake structure from which the plant service water pumps take suction. Large pieces of debris are prevented from reaching the traveling screens by the trash racks. The traveling screen system at Hatch is composed of two traveling screens, two motors, and two screen wash lines. For the intended function of intake structure trash removal, the intake structure is equipped with trash screens and racks to keep debris out of the pump wells. The debris is removed from the screens by the screen wash water.

The screens and racks must remain structurally intact during an accident but are not required to move. Therefore, the applicant only considered the screens and the racks to be in scope for license renewal and not the motors or the screen wash lines. For the intended function of screen wash isolation, isolation of the screen wash lines in the safe shutdown mode is required during a fire to maintain safe shutdown paths 1 and 3.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.1.2 of the LRA. On the basis of its methodology, the applicant identified the portions of the traveling water screens/trash racks system that are within the scope of license renewal on evaluation boundary diagrams DL-11001 and HL-21033. The applicant listed the mechanical components and component functions within the license renewal boundaries that are subject to an AMR. In Table 2.3.4-16 of the LRA, the applicant identified the following 4 component types as subject to an AMR: sight glasses, trash racks, traveling screens, and valve bodies. The applicant identified maintaining pressure boundary as the function of the sight glasses and the valve bodies. The function of the trash racks and traveling screens was identified as debris protection.

2.3.4.2 Staff Evaluation

The staff reviewed the LRA to determine whether there is reasonable assurance that the auxiliary system components and supporting structures that are within the scope of license renewal, and that are subject to AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). This was accomplished as described below.

As part of the evaluation, the staff determined whether the applicant had properly identified the systems, structures, and components within the scope of license renewal and subject to an AMR, pursuant to 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed portions of the FSARs for the auxiliary systems and associated pressure boundary components and compared the information in the FSAR with the information in the LRA to identify those portions that the

applicant did not identify as being within the scope of license renewal and subject to an AMR. The staff then reviewed structures and components that were identified as not being within the scope of license renewal. The staff requested that the applicant provide additional information and/or clarifications for a selected number of these structures and components to verify the following:

- that these structures and components do not have any of the intended functions delineated under 10 CFR 54.4(a), and

- for those structures and components that have an applicable intended function(s), verify that they either perform this function(s) with moving parts or a change in configuration or properties, or that they are subject to replacement based on a qualified life or specified time period, as described in 10 CFR 54.21(a)(1).

The staff also reviewed all system functions to determine if any functions met the criteria of 10 CFR 54.4, but were not identified as intended functions in the LRA.

Access Doors

The staff reviewed the above information related to the access doors system to verify that the intended functions of the access doors system that are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the access doors system in Table 2.3.4-4 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The staff reviewed Section 2.3.4.4 of the LRA to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then verified that the applicant identified all the components within the scope of license renewal in accordance with10 CFR 54.4. Further, the staff verified the completeness of Table 2.3.4-4 to confirm that all the components within the scope of license renewal were included in the application. In addition, the staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were identified as being subject to an AMR.

After the initial review, the staff identified, in a letter dated July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAI in a letter dated August 29, 2000.

In RAI 2.3.4-AD-1, the staff requested the applicant to justify the exclusion of the access door and door seals from within the scope of license renewal and from being subject to an AMR. The applicant responded that the secondary containment access doors and door seals are within the scope of license renewal. The door seals are not subject to an AMR because the

door seals are replaced or repaired based on the performance and conditions under preventive maintenance procedures. Based on the applicant's response to the RAI, the staff concludes that the door seals are not subject to an aging management review.

In a telephone conference on September 13, 2000, the applicant clarified that the "access doors" are identified in Table 2.3.4-4 of the LRA as "structural steel." In an e-mail correspondence dated November 22, 2000, the applicant provided further clarification that the containment integrity function (L48-01) refers to secondary containment integrity, not primary containment integrity. Secondary containment integrity is ensured by the standby gas treatment system drawdown limitations, which are specified in plant technical specifications for secondary containment operability and surveillance requirements of once every 18 months.

On the basis of the staff's review of the LRA, the applicant's responses to the RAI, and followup discussions and correspondence, the staff was unable to find any omissions from the function level scoping boundaries. The staff also compared the components listed in Table 2.3.4-4 of the LRA and the components described in the LRA. After clarification that the access doors are identified as "structural steel" in the table, the staff found the table and the system description consistent.

Condensate Transfer & Storage System

The NRC staff reviewed the above information to verify that the intended functions of the condensate transfer and storage system are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the condensate transfer and storage system in Table 2.3.4-5 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The NRC staff reviewed Hatch Unit 1 FSAR Section 11.9 and Unit 2 FSAR subsection 9.2.6. to determine if there were any system functions not identified as intended functions in accordance with the requirements of 10 CFR 54.4. The staff then reviewed the drawings (HL-16016, HL-16332, HL-16334, HL-26030, HL-26023, HL-26046) of the LRA to verify that the applicant identified all the components within the scope of license renewal in accordance with10 CFR 54.4. Further, the NRC staff verified the accuracy of the drawings and the completeness of Table 2.3.4-5 by sampling the components adjacent to, but outside the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the NRC staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were subject to an AMR.

After the initial review the staff identified, in a letter of July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAI in a letter, dated August 29, 2000.

In reviewing drawing HL-16016, the staff found that valves E51-F009 and E41-F010 are not highlighted. These valves are locked open valves for flow from the condensate storage tank (CST) to the high pressure coolant injection system (HPCI) and the reactor core isolation cooling system (RCIC) serving the intended function of P11-01, ECCS/CRD condensate supply. The staff believed that these valves are within the scope of license renewal. Therefore, the staff requested the applicant to justify why these valves are not highlighted in the drawing. The applicant responded that these two valves are within the scope of license renewal. These valves and associated piping downstream are shown in "phantom" (indicating that the information is supplied for reference only) on drawing HL-16016, and are not highlighted since they appear on other license renewal boundary drawings. Referring to license renewal boundary drawings HL-16332 and HL-16334, these two valves along with the associated piping are highlighted indicating these valves are within the scope of license renewal.

In reviewing the response that in-scope components are highlighted in one drawing but not highlighted in another drawing, the staff was concerned that on-site personnel attempting to inspect or confirm components within functional evaluation boundaries may have difficulty understanding which drawing is the correct one. In a telephone conference, dated September 28, 2000, the applicant stated that implementing procedures are being developed based on functional drawings, scoping and screening procedures, and current licensing basis documents. These documents, along with the staff SER, will provide sufficient guidance and information to allow an NRC inspector to identify the functional evaluation boundaries; SSCs within the boundary and outside the boundary; and structures and components that are subject to an AMR.

The staff requested the applicant to explain why the flow line from the CST to the control rod drive system (CRD) is excluded from the scope of license renewal. The applicant responded that for the CRD system, only the reactivity control and alternate rod insertion functions are within the scope of license renewal for Hatch. A supply of demineralized water from the CST is not required for the CRD system to accomplish these two functions. Therefore, the flow line in question is not within the scope of license renewal.

The staff requested the applicant to justify the exclusion of the two condensate transfer pumps and associated piping and valves from the scope of license renewal. The applicant's response to the RAI did not provide sufficient explanation. In a telephone conference, dated September 13, 2000, the applicant explained that these pumps supply water from demineralized water storage tank to condensate storage tank, which is not an essential water source for the intended safety function. The essential water source for the intended function is from the suppression pool, which has sufficient water to serve the safety function.

The staff questioned the basis for excluding instrument tubing from an AMR. The applicant responded that with the exception of copper, the LRA includes instrument tubing with piping for like materials. There is no copper instrument tubing in scope for functions associated with the condensate transfer and storage system.

On the basis of the NRC staff's review of the LRA and associated drawings, the Hatch Units 1 and 2 FSAR, and the applicant's responses to RAIs, the staff was unable to find any omissions

from the components highlighted in the diagrams that identify the function level scoping boundaries. The NRC staff also compared the components listed in Table 2.3.4-5 of the LRA and the components highlighted in the drawings, and found them consistent.

On the basis of the review described above, the NRC staff has determined there is reasonable assurance that the applicant has adequately identified the intended functions of the condensate transfer and storage system that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4 and the components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Control Building HVAC

The staff reviewed the information related to the control building HVAC system to verify that the applicant identified components that are within the scope of license renewal and that are subject to an AMR. The staff determined whether there is reasonable assurance that the components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff reviewed the information in the LRA and Sections 6.4, 9.4.1, 9.4.7 of the FSAR for Unit 2 and Section 10.9.3.6 of the FSAR for Unit 1. After completing the initial review, the staff issued requests for additional information (RAIs) by letter dated July 14, 2000, regarding the control building HVAC system. The applicant responded to the RAIs in a letter dated August 29, 2000.

In the LRA Section 2.1, the applicant discussed the process for identifying mechanical components subject to an AMR. The applicant's scoping methodology is evaluated by the staff in Section 2.1 of this SER.

In its review of the control building HVAC system, the staff reviewed the control building evaluation boundary drawings HL-16040, Rev. A and HL-11609 for Unit 1, and HL-16042, Rev. A and HL-26116, Rev. A for Units 1 and 2. The drawings show the evaluation boundaries for the portions of the control building HVAC system within the scope of license renewal. The staff also reviewed Table 2.3.4-20 of the LRA that lists components that are subject to an AMR.

The staff also reviewed Sections 6.4, 9.4.1, 9.4.7 of the FSAR for Unit 2 and Section 10.9.3.6 of the FSAR for Unit 1 to determine if there were any portions of the control building HVAC system that met the scoping criteria in 10 CFR 54.4(a) that the applicant did not identify as within the scope of license renewal. The staff also reviewed the FSAR sections to determine if there was a system function that was not identified as an intended function in the LRA, and to determine if there were structures and components (SCs) that have an intended function that might have been omitted from the scope of SCs requiring an AMR. The staff also reviewed the evaluation boundary drawings to determine if any SCs within the evaluation boundaries that were omitted from the scope of SCs requiring an AMR. The staff compared the functions described in the FSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified SCs subject to an AMR from among those identified as within the scope of license renewal.

The applicant identified and listed the SCs that are subject to AMR for the control building HVAC system in Table 2.3.4-20 of the LRA, using the screening methodology described in section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and

documented its findings in Section 2.1 of this SER. The staff sampled SCs from Table 2.3.4-20 to verify that the applicant identified the SCs subject to an AMR. The staff also sampled SCs within the scope of license renewal but not subject to an AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on a qualified life or specified time period.

To ensure that those portions of the control building HVAC system identified as not within the scope of license renewal did not perform any intended functions, the staff issued RAIs on the basis of the information in the FSAR and LRA. The staff noted that LRA Section 2.3.4.20 presents a summary description of the system functions, evaluation boundary drawings highlight the evaluation boundaries, and Table 2.3.4-20 lists the components within the scope of license renewal and subject to an AMR. The corresponding drawings for these systems in the FSAR, however, show additional components that were not listed in Table 2.3.4-20 of the LRA.

The staff requested specific information concerning the exclusion of the following components from the scope of license renewal and/or from an AMR:

(1) damper housing and associated ductwork (HL-16042 (several dampers), HL-16042 @ H7 (cable spreading room)); HL-26116 @ C4 and D4)

(2) filter train housing with carbon and HEPA filters (HL-16042 @ B8 and B9, F8 and F9)

(3) fan housing (HL-16042 @ E12 and F12, B7, E7; H5, H7 (cable spreading room))

(4) air handling units housing and heating and cooling coils (HL-16042 @ B2 and B3, D2 and D3, F2 and F3)

(5) filters (HL-16042 @ B5, F5)

(6) coolers for low-pressure coolant injection (LPCI) inverter room and Unit 2 vital A/C room (text of Section 2.3.4.20)

(7) sealants

In a letter dated August 29, 2000, the applicant provided the following responses:

(1) the damper housing is a part of the damper, which is an active component (NEI 95-10 Revision 0, Appendix B, Item 155); the ductwork is constructed of both carbon steel and galvanized steel and is subject to an aging management review; both types of ductwork are included in Table 2.3.4-20

(2) the filter train housing is subject to an aging management review and is included in Table 2.3.4-20; the carbon and HEPA filter media inside the filter housing are consumables

(3) the in-scope fan housings are a part of fan assemblies, which are active Components (NEI 95-10, Rev, 0, Appendix B, Item 163)

(4) the air-handling units, including the cooling coils, are a part of the active fan assemblies (NEI 95-10, Rev. 0, Appendix B, Item 163); the heating coil housing, however, is subject to an aging management review and is shown on Table 2.3.4-20

(5) the filter media shown on HL-16042 (B5 and G5) is consumable; an aging management review was performed on the filter housing, which is included in Table 2.3.4-20

(6) the coolers for the low-pressure coolant injection (LPCI) inverter room and the Unit 2 vital AC room do not perform an in-scope function; however, the LPCI inverter room cooling coils do provide part of the pressure boundary function for P41-OI but were not subject to AMR since they are part of the active fan assemblies

(7) sealants are not used at plant Hatch to maintain positive pressure for the MCR pressure boundary; sealants used to support intended functions are listed in Table 2.4.13-1

The staff reviewed the applicant's responses concerning the associated ductwork, the filter train housing with carbon and HEPA filters, and the heating coil housing, and found the responses to be acceptable. However, in its response to RAI 2.3.4-CBHVAC-1, the applicant also stated that no damper housing, fan housing, and air handling units, including the cooling coils, are found within the license renewal portions of the control building HVAC system based on NEI 95-10, Appendix B guidance. The staff disagrees with the applicant's exclusion from an AMR of housings for fans, dampers, and air handling units, including cooling coils. The staff's position with regard to the treatment of the housings for fans, dampers, and heating and cooling coils is discussed in detail in the staff's review of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER applies to the treatment of the component passive functions of the control building HVAC system. Resolution of this issue is part of Open Item 2.3.3.2-2.

Additionally, in a telephone conference (telecon) held on October 31, 2000, the applicant clarified that the LPCI inverter room and the Unit 2 vital A/C room coolers are no longer in scope due to a design modification. The applicant committed to provide a description of the design modification that clarifies how the modification impacts the LPCI inverter room and Unit 2 vital A/C room functions. The applicant also committed to address why heating coil housings are not specifically identified in Table 2.3.4-20 of the LRA. The design modification information and the resolution of the issue regarding Table 2.3.4-20 are part of Open Item 2.3.3.2-2.

In RAIs 2.3.4-CBHVAC-2 and 2.3.4-CBHVAC-4, the staff also requested more specific information on the following: (1) description of the areas that constitute the main control room envelope (MCRE) for Units 1 and 2, and (2) the failure to submit evaluation boundary drawing HL-16040 for the control building HVAC system. In a letter dated August 29, 2000, the applicant responded that the MCR envelope consists of an area located on the 164' elevation of the control building and contains approximately 106,000 $ft^{2.}$ This space is enclosed by reinforced concrete walls and floors and is served by the MCRECS, which realigns into a pressurization mode should an accident signal be generated. In this mode, the MCRECS is designed to cool and filter the MCR envelope, maintaining habitability in the control room. In the

pressurization mode, the return air and outside air are directed through the filtration units shown on HL-16042 (Zones B-B, 9 and E, F-B, 9). The HVAC equipment required to perform this function (Z41-02) is included in scope for license renewal and the components subject to an AMR are shown on Table 2.3.4-20. With regard to the missing evaluation boundary drawing, the applicant provided it separately. In summary, the applicant applied the screening criteria prescribed by the Rule in determining the set of long-lived, passive components subject to an AMR.

The staff reviewed, and finds acceptable, the applicant's response concerning the MCRE description, including the applicant's treatment of those components inside the MCRE and identified on evaluation boundary drawing HL-16040, that are within the scope of license renewal and subject to an AMR.

The staff reviewed Section 2.3.4.20 of the LRA, supporting information in the FSAR, and the applicant's responses to the staff's RAIs. In addition, the staff sampled several components in the previously mentioned evaluation boundary drawings of the LRA to determine whether the applicant properly identified the components within the scope of license renewal and subject to an AMR. On the basis of this review, and pending satisfactory resolution of Open Item 2.3.3.2-2, the staff concludes that the applicant has identified those portions of the control building HVAC system that are within the scope of license renewal and subject to an AMR.

Control Rod Drive (CRD) System

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

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

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

After completing the initial review, the staff issued requests for additional information (RAIs) regarding the auxiliary systems, and by letter dated August 29, 2000, the applicant submitted responses to those RAIs, as discussed below.

In RAI 2.3.4-CRD-1, it was stated that the staff believes that the scram discharge volume (SDV) of the control rod drive system (Section 2.3.4 of the LRA) is a passive, long-lived component that meets the requirements of 10 CFR 54.4(a), and therefore, should be subject to an AMR. However, it was not clear in the LRA whether the SDV was subject to an AMR. Therefore, the staff requested the applicant to clarify whether the SDV is subject to an AMR; and if not, to provide a justification for excluding the SDV from an AMR. In response, the applicant confirmed that the SDV components are subject to AMR, and clarified that the components are included in

components supporting CRD intended functions and are shown in Table 2.3.4-1. During a telecon on June 26, 2000, SNC further clarified that the SDV is identified in Table 2.3.4-1 as non-Class 1 stainless steel piping. Boundary drawings HL-16065 and HL-26007 include the SDV components.

On the basis of the staff's review of Section 2.3.4.1 of the LRA, and review of the response to the staff's RAI, the staff concludes that the applicant identified all the components of the CRD system that are within the scope of license renewal and subject to an AMR.

Cranes, Hoists and Elevators

The applicant stated in Section 2.3.4.13 of the LRA that the cranes, hoists and elevators system is within the scope of license renewal because of the reactor building crane and its intended function of handling heavy loads during refueling and maintenance operations. The portions of the system identified as supporting this intended function are the load bearing portions of the crane. The staff reviewed Unit 1 FSAR Section 10.2, "New Fuel Storage," and Unit 2 FSAR Section 9.1, "Fuel Storage and Handling," to verify that the reactor building crane did not have intended functions other than the heavy load handling intended function. In addition, the staff verified that all components supporting the heavy load handling intended function were identified as being within the scope of license renewal.

On the basis of the staff's review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the cranes, hoists and elevators system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information provided in the LRA, the staff reviewed the application to determine whether the applicant properly identified the passive, long-lived components as being subject to an AMR in Table 2.3.4-13 of the LRA. The applicant only identified structural steel as being subject to an AMR. The extent to which structural steel is within the scope of license renewal for the reactor building crane is defined in LRA Section 2.3.4.13 as being the "load bearing components." On the basis of the its review, the staff concludes that there is reasonable assurance that the applicant has adequately captured the passive, long-lived components under the structural steel category on the list of components subject to an AMR in Table 2.3.4- 13. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the cranes, hoists and elevators system subject to an AMR.

Drywell Pneumatics System

The staff reviewed the above information related to the drywell pneumatics system to verify that the intended functions of the drywell pneumatic system that are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the drywell pneumatics system in Table 2.3.4-11 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The staff reviewed the Plant Hatch Unit 1 FSAR Section 10.19 and Unit 2 FSAR subsection 9.3.6 to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the drawings (HL- 16286, HL-16299, HL-28023, and HL-26066) of the LRA to verify that the applicant identified all the components within the scope of license renewal in accordance with 10 CFR 54.4. Further, the staff verified the accuracy of the drawings and the completeness of Table 2.3.4-11 by sampling the components adjacent to, but outside the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were subject to an AMR.

After the initial review, the staff identified, in a letter of July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAIs in a letter dated August 29, 2000.

Section 2.3.4.11 of the LRA states that the drywell pneumatics system receives motive gas from the nitrogen storage tanks. Since the nitrogen storage tanks are passive and long-lived, the staff requested, in RAI 2.3.4-DPS-1, the applicant to justify the exclusion of the tanks from Table 2.3.4-11 for aging management review. The staff also requested the applicant to identify the tanks in applicable drawings. The applicant responded that the nitrogen storage tanks are within scope and subject to an AMR, and are included in the primary containment nitrogen inerting function (T48-01), in Section 2.3.3.7, and in Table 2.3.3-7 (instead of Table 2.3.4-11) of the LRA. The nitrogen storage tanks are highlighted on boundary drawings HL-16000 and HL-26083 for the primary containment purge and inerting system. The staff confirmed that the “storage tank” is listed in Table 2.3.3-7 of the LRA.

Section 2.3.4.11 of the LRA states that the system includes an air receiver, particulate filters, and regulators, among other components. In RAI 2.3.4-DPS-2, the staff requested the applicant to justify the exclusion of these components from being subject to an AMR. The applicant responded that the air receiver was inadvertently omitted from Table 2.3.4-11. Subsequently, in a telephone conference, dated September 13, 2000, the applicant agreed to add the air receiver to Tables 2.3.4-11 and 3.2.4-11 as a part of the revision to the RAI response. By letter dated January 31, 2001, the applicant provided revised Tables 2.3.4-11 and 3.2.4-11 that included the air receiver. The staff notes that the air receiver is identified as a tank in the tables. The staff finds this acceptable.

The applicant stated that the particulate filters include the filter housing and a filter cartridge. The filter housings are included in Table 2.3.4-11. The filter cartridges are consumable items, and thus, short lived. The cartridges are replaced in every refueling outage, and therefore, are not subject to an AMR. “Regulators” are pressure control valves, and are listed in Table 2.3.4-11 as “valve bodies.”

Unit 2 FSAR Section 9.3.6.3 states that a backup supply of nitrogen to the drywell is provided through three interchangeable nitrogen bottles and a manifold system at one of two emergency nitrogen hookup stations. In RAI 2.3.4-DPS-3, the staff requested the applicant to justify the exclusion of nitrogen bottles and manifold system from an AMR. The applicant responded that the nitrogen bottles are short-lived components, and therefore, not subject to an AMR. The nitrogen gas is used up during the course of normal operations. Once the pressure of the gas bottle decreases below a predetermined setpoint, the bottle is replaced and returned to the vendor. The gas bottles have an inspection interval typically once every 10 years. The manifold assembly is subject to an AMR and listed in Table 2.3.4-11 as piping, valves, and flex hoses.

On the basis of the staff's review of the LRA and associated drawings, the Plant Hatch FSARs for Units 1 and 2, the applicant's responses to RAIs, and information provided in a telephone conference on September 13, 2000, and the letter dated January 31, 2001, the staff was unable to find any omissions from the components highlighted in the diagrams that identify the function level scoping boundaries. The staff also compared the components listed in Tables 2.3.4-11 of the LRA and the components highlighted in the drawings, and found them consistent. Therefore, the staff concludes that the applicant has adequately identified the components of the drywell pneumatics system that are within the scope of license renewal and that are subject to an AMR.

Emergency Diesel Generators System

The NRC staff reviewed the above information to verify that the intended functions of the diesel generators system that are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the diesel generators system in Table 2.3.4-12 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The NRC staff reviewed Hatch Unit 1 FSAR Section 8.4 and Unit 2 FSAR Section 8.3 to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the drawings (HL-21074, HL-11631 sheet 1 and 2, HL-11638 sheets 1 and 2) of the LRA to verify that the applicant identified all the components within the scope of license renewal in accordance with10 CFR 54.4. Further, the NRC staff verified the accuracy of the drawings and the completeness of Table 2.3.4-12 by sampling the components adjacent to, but outside the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the NRC staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were subject to an AMR.

After the initial review the staff identified, in a letter of July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAI in a letter, dated August 29, 2000.

The staff had asked the applicant to explain the exclusion of the air receivers A005A, A006A, A003A, and A007A, which are highlighted in drawings HL-21074 and HL-11631, from aging management review. The applicant responded that air receivers are subject to an AMR, and are listed as “tanks” in Table 2.3.4-12. The staff finds this response acceptable.

The staff asked the applicant to identify the components C001A and C010A in drawing HL-11631 and justify the exclusion of these unnamed components from within the scope of license renewal. The applicant responded that C001A and C010A are compressors, which do not perform a passive function. The air receivers, which are within the scope of license renewal, are sized for sufficient air to accomplish the five required starts for the intended function. Each diesel generator is supplied with two air receivers. The staff finds this response acceptable.

In reviewing drawing HL-11631, the staff also found that the scavenging air heat exchanger, engine supply HDR, diesel engine crankcase, and turbo superchargers were highlighted as within the scope of license renewal, but not included in Table 2.3.4-12 of the LRA, as subject to an AMR. The staff requested that the applicant justify the exclusion of these components from an AMR. The applicant responded that these components are part of the diesel generator, which is an active component. Therefore, the applicant determined that these components are not subject to an AMR.

In reviewing drawings HL-21074, HL-11631, HL-11638, the staff found that some of the pumps were highlighted as within the scope of license renewal, but there are no pumps listed in Table 2.3-12 as subject to an AMR. The staff requested the applicant to explain this discrepancy. The applicant explained that on drawings HL-11638 (sheets 1 and 2) and HL-11631 (sheets 1 and 2), all the pumps are part of the diesel generator skid. The applicant further stated that the diesel generator is an active component and, thus, not subject to an AMR. Therefore, the applicant determined that these pumps, which are part of the diesel generator skid, are also not subject to an AMR. However, the pumps that are not part of the diesel generator skid (on drawing HL-21074) are subject to an AMR and appear in Table 2.3.4-19 of the LRA for the fuel oil system. The staff does not agree that pumps can be excluded from an AMR because these pumps are part of the diesel generator skid that constitutes part of a complex assembly.

In a telephone conference on September 13, 2000, the staff expressed its disagreement with the applicant’s decision to exclude these components from an AMR simply because these components are skid-mounted. The staff requested the applicant to provide additional justification for its position. In response, the applicant provided a paper, entitled “Active Assemblies Used in License Renewal.”

The staff has reviewed this paper and does not agree with the applicant’s basis for excluding skid-mounted components that are part of a complex assembly from an AMR.

Regarding complex assemblies, NEI 95-10, Revision 0, stated:

- “There are structures and components that, when combined, are considered a complex assembly (e.g., diesel generator starting air skids or heating, ventilating, and air conditioning refrigerant units). The Rule and associated SOC do not specifically discuss such assemblies. For purposes of performing an aging management review, it is

important to clearly establish the boundaries for review. An applicant should establish the boundaries for such assemblies by identifying each structure or component that makes up the complex assembly and determining whether or not each structure and component is subject to an aging management review. (See example 5 in Appendix C.)"

Example 5 in Appendix C of NEI 95-10, Revision 0, provided an example of a control room chiller complex assembly and guidance on how to establish the boundaries for such an assembly. It notes that once the boundary is determined, long-lived components with a passive function would be appropriately subjected to an AMR.

Components are subject to an AMR if they perform a passive function and are long-lived. A passive function is one performed without moving parts or a change in configuration or properties. A function performed with moving parts or a change in configuration or properties is considered an active function. Components that perform a passive function and are also long-lived must be subject to an AMR, whether they are skid-mounted or not. The staff believes that the water separator, water spray cooler, and reaction chamber are long-lived components with a passive function, and therefore are subject to an AMR. On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components performing a passive function associated with the hydrogen recombiners, and identify AMPs credited with managing the aging effects.

In the staff's evaluation of the Oconee LRA, the staff reached a similar conclusion regarding the treatment of the vendor-supplied diesel generator skid-mounted equipment. Duke had drawn an enclosure around the diesel generator skid and determined that everything within the enclosure was active and therefore not subject to an AMR. The staff disagreed and noted that the assembly included some long-lived components with a passive function which were subject to an AMR. Duke subsequently redefined the evaluation boundaries to ensure that long-lived components with a passive function on the diesel generator skid were subject to an AMR.

On this basis, the staff requests that the applicant identify any applicable aging effects associated with these components, and any other long-lived components with a passive function associated with the emergency diesel generators, and identify AMPs credited with managing the aging effects. This is part of Open Item 2.3.3.2-1

On the basis of the staff's review of the LRA and associated drawings, the Plant Hatch Units 1 and 2 FSARs, and the applicant's responses to RAIs, pending satisfactory resolution of Open Item 2.3.3.2-1, the staff concludes that the applicant has identified the components of the emergency diesel generator system that are within the scope of license renewal and subject to an AMR.

<u>Fire Protection</u>

The Commission's regulations in 10 CFR 54.21(a)(1), state that for those SSC's 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 2.3.3.2 of the LRA, as supplemented by phone conferences which are documented in teleconference summaries dated, September 12 and 28, 2000, October 1, 2000 (by email), October 13, 2000

(by email), and November 15, 2000, to determine whether there was reasonable assurance that the applicant has appropriately identified the components and supporting systems that serve fire protection-intended functions, and are within the scope of license renewal in accordance with 10 CFR 54.4, and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

This evaluation is to determine whether the applicant has properly identified, for the fire protection system, the components which are within the scope of license renewal. The staff will then determine if the components which are within the scope of license renewal were properly identified by the applicant as being subject to an AMR.

In response to RAI 2.3.3.1-1, the applicant stated that Plant Hatch was docketed prior to July 1, 1976, and that the applicable regulatory requirements for the fire protection program were contained in Appendix A to Branch Technical Position (BTP) APCSB 9.5-1, "Fire Protection for Nuclear Power Plants", and Section III.G, III.J, and III.L of Appendix R. The applicant primarily used the FHA as the primary information source during the scoping process for fire protection SSC's. The FHA contains the analyses to demonstrate compliance with Appendix R and Appendix A to BTP 9.5-1. The applicant searched its FHA for commitments made to meet 10 CFR 50.48 (including compliance with Appendix R and Appendix A to BTP 9.5-1) and stated that any structures or components that are relied upon for meeting the regulatory commitments are included within the scope of license renewal.

The staff sampled portions of the FHA, which contains plant commitments and safety evaluations which form the basis of the fire protection program at Plant Hatch. The staff then compared a sample of the fire protection systems and components identified within the FHA to the fire protection system flow diagrams to verify that required components were identified within the evaluation boundaries of the flow diagram and were not excluded from the scope of license renewal. The staff also compared SSC's identified in NRC-approved SERs, which document Plant Hatch's compliance with the provisions of Appendix A to BTP 9.5-1, to the fire protection system flow diagrams to verify if there were additional portions of the fire protection system which were excluded from the scope of license renewal. As part of the evaluation, the staff also reviewed the same flow diagrams for the fire protection system to determine if there were any additional portions of the system piping or components located outside of the evaluation boundary, with intended functions that should have been identified as within the scope of license renewal.

In accordance with 10 CFR 50.48(b), only the requirements of Sections III.G, III.J, and III.O to 10 CFR Part 50, Appendix R were backfit to all nuclear plants to the extent that fire protection features proposed or implemented by the applicant have been accepted by the NRC staff as satisfying the provisions of Appendix A to BTP 9.5-1, as reflected in staff fire protection safety evaluation reports. The staff was concerned that the applicant had excluded from its component database fire protection components which were identified in an NRC-approved SER dated October 4, 1978. This SER documents Plant Hatch's compliance with Appendix A to BTP 9.5-1. During telephone conferences (telecons) on September 13, 2000 and September 28, 2000, the staff questioned if the fire protection SSC's identified in the October 4, 1978 SER were evaluated during the scoping process. During the scoping inspection on September 11-15, 2000, the applicant provided the NRC inspector with its license renewal docketed correspondence list. This list shows all of the documents that the applicant reviewed for the scoping of Fire protection

SSC's. The staff noted that no SER's prior to 1982, that show compliance to Appendix A to BTP 9.5-1, were included in this list. In a phone conference, documented in telecon summary dated November 15, 2000, the applicant agreed to identify the path that shows how the components from the 1978 SER were captured in the FHA for compliance with Appendix A to BTP 9.5-1. The applicant referred the staff to a letter, with an accompanying SER, from NRC to Georgia Power Company dated November 24, 1986. On page 2 of the SER for the November 1986 letter, proposed change 1 was accepted, and the NRC stated "the applicant's compliance with the staff's SER [10/4/78] is now documented in Section 9.4, Appendix D, of the FHA." On the basis of this November 24, 1986 SER, the applicant has appropriately demonstrated to the staff how they were able to include components from the 1978 SER in the scoping methodology by using the FHA as the primary scoping document for fire protection.

The staff reviewed the October 4, 1978 SER to ensure that the fire protection components excluded from the scope of license renewal based on the applicant's evaluation of the FHA, were not required to meet BTP 9.5-1, based on the October, 1978 SER. Fire protection components listed in the October 4, 1978 SER, which were initially excluded from the scope of license renewal, include the control building 112' elevation suppression system for protection of the lube oil tanks and the fire hydrants required for compliance with 10 CFR 50.48. After the staff's scoping inspection, the applicant placed these components in scope and revised plant documentation to show that they were required for compliance with 10 CFR 50.48 and are included within the scope of license renewal and are subject to an AMR.

For the following components, the staff was concerned that these components appeared to have fire protection intended functions that are required for compliance with 10 CFR 50.48 which were not included within the scope of license renewal and were not subject to an AMR.

- the Unit 2 remote shutdown panel (RSP) halon suppression system
- the radwaste fire suppression system

The Unit 2 remote shutdown panel halon suppression system is identified in the LRA as fire protection intended function X43-02. However, the associated flow diagram (HL-50048) shows that components which support the halon system were removed from within the scope of license renewal. In response to RAI 2.3.4-FPS-5, the applicant stated that at the time of submittal of the LRA, the RSP halon suppression system was within the scope of license renewal. However, an FHA change physically removed this system from the plant. After questioning SNC on these findings, SNC provided a 50.59 evaluation, "Licensing Document Change Request 99-181, Revision 0," dated November 19, 1999, and FHA revision 18C. These documents analyzed the removal of the RSP halon fire suppression system from regulatory requirements and provided the rationale for the decision. During the scoping inspection, the inspector questioned the appropriateness of using the 10 CFR 50.59 process to remove the regulatory requirement and the physical function of originally installed fire protection equipment without a prior NRC review. In an SER dated April 18, 1984 (located in FHA Section 9.3, Appendix C) the staff approved several exemptions from Section III.G.3 and III.L Appendix R to 10 CFR 50.48. Page 16 to Enclosure 2 of the SER, "RB South of Column Line R19-U2" states that the staff was concerned that for locations where components for redundant shutdown pathways were either not separated by the water curtain or were located in close proximity to each other on either side of the curtain, a fire would cause damage to both, such as RSPs 2C82-P001A and 1B. Since the applicant protected these panels by non-combustible barriers, an automatic halon fire

suppression system, and fire detectors, the staff concluded that the existing fire protection, with the proposed modifications, would achieve an acceptable level of safety to that provided by Section III.G.2 and granted the applicant's exemption. Furthermore, in SNC's July 22, 1986 letter which contained their FHA, Section 4.11 of the FHA states that "The Unit 2 RSP is also equipped with an internal Halon 1301 fire suppression system." This issue is being evaluated by the NRC Region and headquarters staff for resolution as a current licensing basis issue.

In the applicant's docketed response to RAI-2.3.4-FPS-8, SNC stated that the radwaste fire suppression system was excluded from within the scope of license renewal on the basis that the system was not included in the regulatory requirements because it is not relied upon in FHA Section 9.2, Appendix B. The staff disagrees that the fire suppression systems for the radwaste building are not included in the regulatory requirements for Plant Hatch.

In an NRC-approved SER dated October 4, 1978, the staff reviewed the design criteria and bases for the water suppression systems in various areas that were approved to meet the guidelines of Appendix A to BTP 9.5-1. The radwaste building was one of the plant areas listed, which was equipped with an automatic suppression system. Furthermore, the applicant's October 1976 FHA to the staff (which the staff used as the basis for their October 4, 1978 SER) states that there is an automatic deluge system provided for dry waste storage and for charcoal filters. This follows the guidance of Section F.14 from Appendix A to BTP 9.5-1, which states that the radwaste building should have automatic sprinklers in all areas where combustible material is located. The scope of components required to satisfy 10 CFR 50.48 includes those components required for compliance with Appendix A to BTP 9.5-1.

By letter dated November 24, 1986, the staff approved a license amendment change for Plant Hatch in accordance with Generic Letter 86-10, "Implementation of Fire Protection Requirements". The amendment revises the Technical Specification (TS) for Units 1 and 2 to relocate the fire protection surveillances to the FHA. It also states that the applicant's compliance with Appendix A to BTP 9.5-1, as shown in the staff's October 4, 1978 SER, is now documented in FHA Section 9.4, Appendix D. The FHA submitted to the staff at the time of the license amendment is dated July 22, 1986. Furthermore, in Proposed Change 1 to the November 24, 1986 license amendment safety evaluation, the staff states that this change also deletes the requirement that all modifications identified in the NRC's SER dated October 4, 1978 be completed. In accordance with the October 4, 1978 SER, the radwaste building suppression system was already installed to satisfy Appendix A to BTP 9.5-1.

As mentioned above, Plant Hatch's compliance with Appendix A to BTP 9.5-1 is documented in Section 9.4, Appendix D of the FHA. With respect to the radwaste building, the staff reviewed the Plant Hatch FHA dated July 22, 1986 and concludes that fire suppression for certain areas in the radwaste building were included in the 1986 FHA. Specifically, Section IV.B.4.d of the FHA states that "fixed automatic water spray systems are installed in all charcoal filters in the plant". The radwaste building contains charcoal filters which are protected by fixed sprinkler systems. Therefore, the fire suppression piping leading to the charcoal filters, including the nozzles and sprinkler heads, should be included within the scope of license renewal and subject to an AMR.

In addition, Section IV.D of the FHA states that the guidelines for specific plant areas is presented for each specific plant area throughout the FHA. In both the 6/86 and 7/87 revisions

to the FHA, the FHA analysis of fire area/zone 2301 (Radwaste Building - All Elevations) states that , “all sections of this area which contain specific fire hazards (charcoal filters) or high concentrations of combustibles (dry waste storage area, Radwaste Control Room) are equipped with detection, suppression, or both.” Specifically, the west central portion of fire zone 2301J over the drywaste storage section is equipped with a wet pipe suppression system. To the staff’s knowledge, the applicant has not submitted any information to the staff to show that the radwaste suppression system has been physically removed or altered so that it can’t perform it’s intended function and that no plant evaluations through 50.59 have determined that this suppression system is no longer required for compliance with Appendix A to BTP 9.5-1.

Therefore, it is the staff’s view that the radwaste suppression system should be included within the scope of license renewal and subject to an AMR. This issue will be tracked as Open Item 2.3.4.2-1.

After the staff determined which components were within the scope of license renewal, the staff determined whether the applicant properly identified the components subject to an AMR from among those identified as being within the scope of license renewal. The staff reviewed selected components that the applicant identified as being within the scope of license renewal to verify that the applicant had identified these 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 on the basis of a qualified life or specified time period.

The staff reviewed mechanical components on flow diagrams and compared them to the list of components with intended functions that the applicant presented in Table 2.3.4-18 of the LRA, to verify that there were no omissions of passive, long-lived components that were subject to an AMR. The staff was concerned that the applicant’s sprinkler head visual inspections would not be sufficient for an AMP throughout the period of extended operation and asked the applicant, in RAI 2.3.4-FPS-10, to discuss if NFPA 25, Section 2.3.3.1, “Sprinklers”, would be implemented at Plant Hatch. The staff’s evaluation of this issue can be found in Section 3.1.18 of this SER.

In addition, the staff asked the applicant to justify the exclusion of fire extinguishers, air packs, and CO_2 hoses from an AMR. The applicant provided justification in an email to the staff dated October 13, 2000 to support that these components are short-lived and therefore, by 10 CFR 54.21, are excluded from an AMR. The applicant considers that these components are short-lived based on replacement intervals established by plant procedures. CO_2 fire extinguishers are replaced every 5 years; dry chemical fire extinguishers are replaced every 12 years, air packs are replaced every 15 years; CO_2 hoses are replaced every 5 years. The plant procedures also specify inspection and testing intervals. Water hoses are condition and performance monitored routinely, and replaced based on degradation criteria specified in a site- approved procedure. By plant procedure, water hoses are to be unracked, visually inspected, and hydrostatically tested every 2 years. Water fire hoses that do not meet the inspection or hydrostatic test criteria are replaced. Water hoses were inadvertently omitted from Table 3.2.4-18. On the basis of the information provided by the applicant and summarized above, the staff concludes that the applicant has provided an acceptable basis to exclude these components from an AMR.

The staff did not find any other omissions of long-lived, passive components with intended functions.

On the basis of its review of the information presented in Section 2.3.4.18 of the LRA, the applicant's responses to the staff's RAIs, and additional information provided in telecons between the staff and the applicant, and pending resolution of Open Item 2.3.4.2-1, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the fire protection system that are within the scope of license renewal and subject to an AMR.

Fuel Oil System

The NRC staff reviewed the above information to verify that the intended functions of the fuel oil system that are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the fuel oil system in Table 2.3.4-19 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The NRC staff reviewed Hatch Unit 1 FSAR Section 8.4 and Unit 2 FSAR Section 9.5.4 to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the drawing (HL-11037, HL-11631 sheet 2, HL-11638 sheet 2, and HL-21074) of the LRA to verify that the applicant identified all the components within the scope of license renewal in accordance with10 CFR 54.4. Further, the NRC staff verified the accuracy of the drawings and the completeness of Table 2.3.4-19 by sampling the components adjacent to, but outside the highlighted portion of the system to verify that all the components within the scope of license renewal were included in the application. In addition, the NRC staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of CFR 54.21(a)(1) were subject to an AMR.

After the initial review, the staff had a few questions in identifying components in the drawings. In a telephone conference on July 6, 2000, the applicant responded the staff's questions by clarifying the information and identifying all the fuel oil storage tanks in the drawings (HL-11037 and HL-21074) so that the staff was able to complete its review.

On the basis of the NRC staff's review of the LRA and associated drawings, the Hatch Units 1 and 2 FSAR, and the applicant's responses in the telephone conference, the staff was unable to find any omissions from the components highlighted in the diagrams that identify the function level scoping boundaries. The NRC staff also compared the components listed in Table 2.3.4-19 of the LRA and the components highlighted in the drawings, and found them consistent.

On the basis of the review described above, the NRC staff has determined there is reasonable assurance that the applicant has adequately identified the intended functions of the fuel oil system that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4 and the components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Instrument Air System

The NRC staff reviewed the above information to verify that the intended functions of the instrument air system that are within the scope of license renewal and the components that are subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components subject to an AMR for the instrument air system in Table 2.3.4-9 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The NRC staff reviewed Hatch Unit 1 FSAR Section 10.11 and Unit 2 FSAR subsection 9.3.1 to determine if there were any system functions not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the drawings (HL-16299, HL-11667, HL-16251, HL-28023, HL-26064, HL-26070) of the LRA to verify that the applicant identified all the components within the scope of license renewal in accordance with10 CFR 54.4. Further, the NRC staff verified the accuracy of the drawings and the completeness of Table 2.3.4-9 by sampling the components adjacent to, but outside the highlighted portion of the system, to verify that all the components within the scope of license renewal were included in the application. In addition, the NRC staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were subject to an AMR.

After the initial review the staff identified, in a letter of July 14, 2000, areas where additional information was needed to complete its safety review. The applicant responded to the RAI in a letter, dated August 29, 2000.

In Unit 2 FSAR Section 9.3.1.2, it states that the instrument air system includes an air dryer and two 100% capacity pre- and after-filters connected in parallel. The staff requested the applicant to justify the exclusion of the air-dryer, pre- and after-filters from Table 2.3.4-9 for aging management review. The applicant responded that the only equipment that is within the scope of license renewal are the gas accumulators and the associated piping and valves. During normal operation, the accumulators are filled with dry nitrogen. The accumulators can be used following a design basis accident to provide additional operational flexibility for certain air-operated valves. The air dryer, pre-filters, and after-filters are located in the portion of the system that is not associated with the accumulators and are not relied upon to perform a safety function.

Since the accumulators are within the scope of license renewal and subject to an AMR, the staff asked the applicant why the accumulators are not listed in Table 2.3.4-9 for aging management review. The applicant stated that the accumulators are listed in the table as “air receivers.”

On the basis of the NRC staff’s review of the LRA and associated drawings, the Hatch Units 1 and 2 FSAR, and the applicant’s responses to RAIs, the staff was unable to find any omissions from the components highlighted in the diagrams that identify the function level scoping boundaries. The NRC staff also compared the components listed in Table 2.3.4-9 of the LRA and the components highlighted in the drawings, and found them consistent.

On the basis of the review described above, the NRC staff has determined there is reasonable assurance that the applicant has adequately identified the intended functions of the instrument air system that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4 and the components that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

Insulation

The applicant stated in Section 2.3.4.3 of the LRA that insulation in various locations outside the drywell is within the scope of license renewal because of its intended function. Specifically, the applicant identified the intended functions of insulation as retaining heat in process piping and equipment, prevent condensation on cold surfaces, protect equipment and personnel from high temperatures, prevent freezing in cold areas of the plant, and protect piping heat tracing. The applicant provided seven drawings for Unit 1 and five drawings for Unit 2 that had intended function designations marked on the drawing to indicate piping and equipment insulation that is within the scope of license renewal. These drawings are DL-11001, DL-11004, HL-11033 (sheet 1), HL-11600, HL-16061, HL-16332, HL-16334, HL-21033, HL-21039, HL-26009, HL-26020, and HL-26023. The staff reviewed these drawings to ensure that the in scope insulation was appropriately identified on the drawings. The staff sampled portions of the systems in these drawings that did not have insulation identified as in scope to verify that the insulation in these areas did not perform an intended function. The staff compared the drawings with the system descriptions in the FSAR, LRA, and Technical Specifications to ensure that intended functions were not performed by insulation identified as not within the scope of license renewal. Examples of written descriptions and technical requirements that were reviewed by the staff include:

- Sections 3.6.1.5 and B3.6.1.5, “Drywell Air Temperature,” of the Unit 2 Technical Specifications.

- Sections 9.4.2.2.3, “ECCS Room Coolers,” and 4.2.3.4, “SLCS,” of the Unit 2 FSAR.

- Sections 2.3.4.1, “Control Rod Drive (CRD) System,” 2.3.3.5, “Reactor Core Isolation Cooling System (RCIC),” and 2.3.4.15, “Reactor Building HVAC System” of the LRA.

On the basis of the staff’s review of these documents and drawings, the staff identified several questions that were forwarded as RAIs to the applicant by letter dated July 14, 2000. The following additional information was provided by the applicant in their RAI response dated August 29, 2000:

- The insulation on heat bearing piping and equipment located in the Unit 1 and 2 RHR, CS and HPCI rooms is within the scope of license renewal.

- Although the insulation on heat bearing piping and equipment located in the RCIC pump room is not required to be within the scope of license renewal, it is conservatively included within scope.

- The insulation on heat bearing piping and equipment located in the CRD pump room is not credited in the sizing of the room coolers, and therefore, is not within the scope of license renewal.

- Insulation that is within the scope of license renewal and located on outdoor piping to prevent freezing ceases to be in scope when the piping passes into either an environmentally controlled atmosphere or underground.

- Large bore piping (12 inch diameter or greater) located outdoors, the condensate storage tank, and the fire protection storage tanks are not insulated per plant design.

- The standby liquid control (SLC) tank is insulated, but the insulation is not within the scope of license renewal because it is not needed to maintain the sodium pentaborate in solution. The SLC tank is located in an environmentally controlled portion of the plant.

The staff found the applicant's RAI responses to be acceptable. On the basis of the staff's review of the LRA, the drawings provided by the applicant, supporting information in the FSAR, and the applicant's RAI responses, the staff has reasonable assurance that all portions of the insulation system performing an intended function meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information provided in the LRA, the staff evaluated insulation components to determine whether the applicant properly identified the passive, long-lived components as being subject to an AMR in Table 2.3.4-3 of the LRA. The staff verified that the passive, long-lived components identified in LRA Section 2.3.4.3 appeared on the list of components subject to an AMR in Table 2.3.4-3. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the insulation system subject to an AMR.

<u>Outside Structures HVAC</u>

The staff reviewed the above information related to the outside structures HVAC system to verify that the applicant identified the components within the scope of license renewal and subject to an AMR. The staff determined whether there is reasonable assurance that the components within the scope of license renewal and subject to an AMR have been identified in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the information in the LRA and Sections 9.4.5 and 9.4.10 of the FSAR for Unit 2. After completing the initial review, the staff issued a request for additional information (RAI) by letter dated July 14, 2000. The applicant responded to the RAI by letter dated August 29, 2000.

In LRA Section 2.1, the applicant discussed the process for identifying mechanical components subject to an AMR. The applicant's scoping methodology is evaluated by the staff in Section 2.1 of this SER.

In its review, the staff reviewed the evaluation boundary drawing HL-44073, Rev. A. The drawing shows the evaluation boundaries for the portions of the outside structures HVAC system that are within the scope of license renewal. The staff also reviewed Table 2.3.4-17 of the LRA that lists components subject to an AMR.

The staff also reviewed Sections 9.4.5 and 9.4.10 of the FSAR for Unit 2 to determine if there were any portions of the outside structures HVAC system that met the scoping criteria in 10 CFR 54.4(a) that the applicant did not identify as within the scope of license renewal. The staff also reviewed the FSAR sections to determine if there was a system function that was not identified as an intended function in the LRA, and to determine if there were structures and components (SCs) that have an intended function that might have been omitted from the scope of SCs requiring AMR. The staff also reviewed the evaluation boundary drawing to determine if any SCs within the evaluation boundaries were omitted from the scope of SCs requiring AMR under 10 CFR 54.4(a)(1). The staff compared the system and intended functions described in the UFSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified SCs subject to an AMR from among those identified as within the scope of license renewal.

The applicant identified and listed the SCs subject to an AMR for the outside structures HVAC system in Table 2.3.4-17 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SCs from Table 2.3.4-17 to verify that the applicant did identify the SCs subject to an AMR. The staff also sampled SCs that were within the scope of license renewal but not subject to an AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on a qualified life or specified time period.

To help ensure that those portions of the outside structures HVAC system identified as not within the scope of license renewal did not perform any intended functions, the staff issued an RAI on the basis of the applicable information in the FSAR and LRA. The staff noted that Section 2.3.4.17 of the LRA presents a summary description of the system functions, that evaluation boundary drawings highlight the evaluation boundaries of the outside structures HVAC system, and that Table 2.3.4-17 of the LRA lists components within the scope of license renewal and subject to an AMR. The corresponding drawings for this system in the FSAR, however, show additional components that were not listed in Table 2.3.4-17.

The staff requested specific information concerning the exclusion of the following components from the scope of license renewal and/or from an AMR:

(1) roof-mounted exhaust ventilators housing (each with backdraft damper and vent fan), (HL-44073 @ G8, G9, and G10)

(2) wall-mounted unit heater housing (HL-44073 @ F7)

(3) gravity-operated louvers (each with inlet screen), (HL-44073 @ D6 and E6)

In the letter dated August 29, 2000, the applicant provided the following responses:

(1) roof-mounted exhaust ventilator housing is part of an active component (fan and damper assembly - see NEI 95-10, Rev. 0, Appendix B, Items 155 and 163) and consequently, no AMR is required

(2) wall-mounted unit heater housing is part of an active component (heater) and consequently, no AMR is required

(3) gravity-operated louvers with inlet screens are active components and consequently, no AMR is required

In its response to RAI 2.3.4-OSHVAC-1, the applicant stated that roof-mounted exhaust ventilator housings and wall-mounted unit heater housings are not subject to an AMR, since these housings are part of active components (i.e., fan/damper assembly and heater for each, respectively). The staff disagrees with the applicant's exclusion from an AMR for roof-mounted exhaust ventilator and wall-mounted unit heater housings. The staff's position with regard to the treatment of the housings for roof-mounted exhaust ventilators and wall-mounted unit heaters is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER also applies to the treatment of the component passive functions of the outside structures HVAC system. Resolution of this issue is part of Open Item 2.3.3.2-2.

The staff reviewed Section 2.3.4.17 of the LRA, supporting information in the FSAR, and the applicant's responses to the staff's RAI. In addition, the staff sampled several components in the previously mentioned evaluation boundary drawings of the LRA to determine whether the applicant properly identified the components that are within the scope of license renewal and that are subject to an AMR. On the basis of its review, the staff concludes that, pending satisfactory resolution of Open Item 2.3.3.2-2, the applicant has adequately identified the components of the outside structures HVAC system that are within the scope of license renewal and that are subject to an AMR.

Plant Service Water

The staff reviewed Section 2.3.4.7 of the LRA and FSAR Units 1 and 2, Sections 10.7 and 9.2.1, respectively to determine whether there is reasonable assurance that the applicant appropriately identified the PSW components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4, and that are subject to an AMR in accordance with the requirements of 10 CFR 54.21 (a)(1).

The applicant provided evaluation boundary diagrams HL-11004, HL-11600, HL-11609, HL-21033, and HL-21035 for the PSW and identified the mechanical components within the scope of license renewal. The applicant highlighted the diagrams to identify those portions of the components which perform at least one intended function meeting the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the description in the FSAR to ensure they were representative of the PSW system. The staff verified that the components not highlighted did not perform any intended functions meeting the requirements of 10 CFR 54.4.

Using the information on the PSW flow diagrams, the staff sampled several components to determine whether the applicant properly identified the passive long-lived components on the list of components as subject to an AMR. The staff also verified that the passive long-lived components are highlighted on the flow diagrams and appeared on the list of components subject to an AMR for the PSW system. No omissions were identified.

In a letter dated July 14, 2000, the staff issued RAI 2.3.4-PSW-1 regarding the functional boundary of turbine building isolation piping that ends in the middle of the piping run, and does not appear to be within the scope of license renewal. By letter dated August 29, 2000, the applicant stated that drawing HL-11600 shows that turbine building service water flow is monitored by safety-related differential pressure (dP) switches downstream of the isolation valves. These switches are needed to close the isolation valves to isolate the nonsafety loads from the rest of the system during a break. The isolation valves and instrumentation for these dP switches are within the scope of license renewal and subject to an AMR. The dP switches located downstream of these valves detect flow and are required for proper isolation of the line. Because the location of the dP switches and the associated instrumentation extend beyond the point that would normally serve as the evaluation boundary, the applicant conservatively extends the AMR evaluation boundary up to the first anchor point at the valve box located beyond the dP switches' location. The applicant committed to revising the drawing to include reference notes that depict this condition. By letter dated January 31, 2001, the applicant provided a revised version of evaluation boundary drawing HL-11600, which identifies the valve box walls which serve as the boundary for scoping evaluation. The staff finds this acceptable.

The applicant also responded that the loop seals to the diesel generator coolers in drawing HL-21033 provide a sealing function and keep the diesel generator coolers full of water by preventing the service water from leaving the cooler because of the vacuum created in the service water discharge line to the river. The loop seals and associated components are safety-related and are within the scope of license renewal. The piping down stream of the loop seal connects to the radwaste dilution line, which is nonsafety-related and discharges the water to the river. A break downstream of the loop seal piping will not impact the sealing function.

Also, during a scoping inspection conducted from September 11 through September 15, 2000, the staff identified a guard pipe surrounding part of the PSW piping. The applicant stated that the function of this guard pipe could not be verified or confirmed in any plant licensing documents, and therefore, concluded that this guard pipe was not within the scope of license renewal. The applicant, however, stated that the PSW piping section that runs through the guard pipe is within the scope of license renewal and subject to an AMR. The applicant committed to perform a one-time inspection of the PSW outer piping surface inside the guard pipe to verify the integrity of this portion of the PSW piping. The one-time inspection is discussed in the response to RAI 3.1.4-1 and is evaluated in Section 3.4.3.2 of this SER.

On the basis of its review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the PSW system with intended funtions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal. The staff has also verified that all passive long-lived components have been identified as subject to an AMR for the PSW system. No omissions were identified.

Primary Containment Chilled Water

The applicant stated in Section 2.3.4.10 of the LRA that the PCCW system is within the scope of license renewal because of its containment integrity intended function. The applicant further stated that the in-scope components are those portions of the PCCW system that form a closed loop inside containment. The applicant provided one drawing (HL-26081) for Unit 2 that is color-coded to indicate the piping from this system that is within the scope of license renewal.

Essentially all of the piping inside containment except small bore piping downstream of vent and drain isolation valves is indicated as within the scope of license renewal. The staff reviewed the drawing and found the piping identified as within the scope of license renewal to be consistent with the intended function description in LRA Section 2.3.4.10.

On the basis of the staff's review of the LRA, the applicant's RAI responses, and supporting information in the FSAR, the staff has reasonable assurance that all portions of the PCCW system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information provided in the LRA, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components on the list of components as being subject to an AMR in Table 2.3.4-10 of the LRA. The staff verified that the passive, long-lived components identified in Section 2.3.4.10 appeared on the list of components subject to an AMR in Table 2.3.4-10. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the PCCW system that are subject to an AMR.

Reactor Building Closed Cooling Water

The applicant provided evaluation boundary diagrams HL-16009, HL-16066, HL-26003, and HL-26055 of the RBCCW and identified the mechanical components subject to an AMR and their functions. The applicant highlighted the detailed flow diagrams to identify those portions of the RBCCW system within the scope of license renewal. The applicant highlighted those components which perform at least one intended function meeting the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the descriptions in the FSAR to ensure they were representative of the RBCCW system. The staff verified that the components not highlighted did not perform any intended functions meeting the requirements of 10 CFR 54.4.

On the basis of a review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the RBCCW system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information on the flow diagrams for the RBCCW, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components on the list of components as subject to an AMR. The staff verified that the passive, long-lived components highlighted on the flow diagrams appeared on the list of components subject to an AMR for the RBCCW system. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the RBCCW system subject to an AMR.

Reactor Building HVAC

The staff reviewed the above information to verify that the applicant identified the reactor building HVAC system components that are within the scope of license renewal and that are subject to an AMR. The staff determined whether there is reasonable assurance that the reactor building HVAC system components within the scope of license renewal and subject to an AMR

have been identified in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1). The staff reviewed the information in the LRA and Sections 10.9 and 9.4.2 of the FSAR for Units 1 and 2, respectively. After completing the initial review, the staff issued requests for additional information (RAIs) by letter dated July 14, 2000, regarding the reactor building HVAC system. The applicant responded to the RAIs by letter dated August 29, 2000.

In LRA Section 2.1, the applicant discussed the process for identifying mechanical components subject to an AMR. The applicant's scoping methodology is evaluated by at the staff in Section 2.1 of this SER.

In its review of the reactor building HVAC system, the staff reviewed the reactor building HVAC system evaluation boundary drawings. The drawings show the evaluation boundaries for the portions of the reactor building HVAC system within the scope of license renewal . The staff also reviewed Table 2.3.4-15 of the LRA that lists components subject to an AMR.

The staff also reviewed Sections 10.9 and 9.4.2 of the FSAR for Units 1 and 2, respectively, to determine if there were any portions of the reactor building HVAC system that met the scoping criteria in 10 CFR 54.4(a) that the applicant did not identify as within the scope of license renewal. The staff also reviewed the FSAR sections to determine if there was a system function that was not identified as an intended function in the LRA, and to determine if there were structures and components (SCs) that have an intended function that might have been omitted from the scope of SCs requiring an AMR. The staff also reviewed the reactor building HVAC evaluation boundary drawings to determine if any SCs within the evaluation boundaries were omitted from the scope of SCs requiring an AMR. The staff compared the system and intended functions described in the FSAR with those identified in the LRA. The staff then determined whether the applicant had properly identified SCs subject to an AMR from among those identified as within the scope of license renewal.

The applicant identified and listed the SCs subject to an AMR for the reactor building HVAC system in Table 2.3.4-15 of the LRA, using the screening methodology described in Section 2.1 of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled SCs from Table 2.3.4-15 to verify that the applicant identified the SCs subject to an AMR. The staff also sampled SCs that were within the scope of license renewal but not subject to an AMR to verify that these SCs performed their intended functions with moving parts or with a change in configuration or properties, or were subject to replacement based on a qualified life or specified time period.

To help ensure that those portions of the reactor building HVAC system identified as not within the scope of license renewal did not perform any intended functions, the staff issued an RAI on the basis of the applicable information in the FSAR and the LRA. The staff noted that Section 2.3.4.15 of the LRA presents a summary description of the system functions, evaluation boundary drawings highlight the evaluation boundaries of the reactor building HVAC system, and Table 2.3.4-15 of the LRA lists components within the scope of license renewal and subject to an AMR. The corresponding drawings for this system in the FSAR, however, show additional components that were not listed in Table 2.3.4-15.

In RAIs 2.3.4-RBHVAC-1, 2.3.4-RBHVAC-2, and 2.3.4-RBHVAC-3, the staff requested specific information concerning the exclusion of the following components from the scope of license renewal and/or from an AMR:

(1) air operated valve bodies, air-operated damper housing, and associated ductwork (Unit 1)

(2) safeguards equipment room cooler housing, especially Control Rod Drive (CRD) pump room cooler housing that is not identified as being within scope (Unit 1)

(3) air-operated valve bodies, air-operated damper housing, and associated ductwork (Unit 2)

(4) safeguards equipment room cooler housing, especially CRD pump room cooler housing that is not identified as being within scope (Unit 2)

(5) sealant materials

(6) ductwork (Unit 1)

In the letter dated August 29, 2000, the applicant provided the following responses:

(1) air-operated valve dampers and associated damper operators (Unit 1) are active components and therefore not subject to AMR; damper operators consist of control valves and piping

(2) though safeguards equipment cooler housings (Unit 1) are within scope for license renewal, cooler housings are considered to be part of an active component (fan-coil unit) and therefore, no AMR is required for these components

(3) air-operated valve dampers and associated damper operators (Unit 2) are active components and therefore are not subject to AMR

(4) though safeguards equipment cooler housing (Unit 2) are within scope for license renewal, cooler housings are considered to be part of an active component (fan-coil unit) and therefore, no AMR is required for these components

(5) sealant materials used to protect against unfiltered out-leakage from secondary containment are within scope for license renewal and are shown as “panel joint seals and sealants” in Table 2.4.5-1 of the LRA

(6) ductwork identified by the staff is not within scope for license renewal; ductwork within scope for license renewal and subject to AMR is shown in Table 2.3.4-15 of the LRA and appears as highlighted ductwork on the appropriate boundary drawings

The staff reviewed the applicant’s response for sealant materials and found the response to be acceptable. However, in its response to RAI 2.3.4-RBHVAC-1, the applicant stated that safeguards equipment room cooler housings are not subject to an AMR, based on NEI 95-10,

Appendix B guidance. With regard to this RAI, the applicant also did not address the scope of license renewal and an AMR as relates to air-operated valve bodies, air-operated damper housings, and associated ductwork. Additionally, in a telephone conference (telecon) held on October 31, 2000, the applicant agreed to reconsider its response to RAI 2.3.4-RBHVAC-3, concerning whether certain ductwork identified by the staff is within the scope of license renewal and is subject to an AMR.

The staff believes that the safeguards equipment room cooler housings may be within the scope of license renewal and subject to an AMR. The staff's position with regard to the treatment of the housings for the safeguards equipment room coolers is discussed in detail in the staff's evaluation of the standby gas treatment system in Section 2.3.3 of this SER. The staff's position in Section 2.3.3 of this SER applies to the treatment of the component passive functions of the reactor building HVAC system. Resolution of this issue, including the scoping clarification for the air-operated valve bodies, air-operated damper housing, and associated ductwork, is part of Open Item 2.3.3.2-2.

The staff reviewed Section 2.3.4.15 of the LRA, supporting information in the FSAR, the applicant's responses to the staff's RAI, and additional information provided in a telephone conference on October 31, 2000. In addition, the staff sampled several components in the previously mentioned evaluation boundary drawings of the LRA to determine whether the applicant properly identified the components that are within the scope of license renewal and that are subject to an AMR. On the basis of the staff's review, pending satisfactory resolution of Open Item 2.3.3.2-2, the staff concludes that the applicant has adequately identified the components of the reactor building HVAC system that are within the scope of license renewal and that are subject to an AMR.

Refueling Equipment System

The applicant stated that the RE system was within the scope of license renewal because of its fuel/control rod handling intended function. The portions of the system identified as supporting this intended function include the refueling bridge, grapple, hoists, spent fuel servicing equipment, tools, and refueling interlocks. The staff reviewed Unit 1 FSAR Section 7.6, "Refueling Interlocks," and Unit 2 FSAR Section 9.1, "Fuel Storage and Handling." The staff verified that the RE system did not have intended functions other than the fuel/control rod handling intended function. In addition, the staff verified that all components supporting the fuel/control rod handling intended function were identified as being within the scope of license renewal.

On the basis of the staff's review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the RE system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal. Using the information provided in the LRA, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components on the list of components as being subject to an AMR in Table 2.3.4-2 of the LRA. The staff verified that the passive, long-lived components identified in Section 2.3.4.2 appeared on the list of components subject to an AMR in Table 2.3.4-2. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the RE system subject to an AMR.

Sampling System

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

The staff reviewed Section 2.3.4.6 of the LRA to determine of the applicant has identified the components in the sampling system that are within the scope of license renewal and subject to and AMR.

On the basis of the staff's review of the information presented in Section 2.3.4.6 of the LRA and the supporting information in the Plant Hatch FSAR, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the sampling system that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

Tornado Vents

The applicant stated in Section 2.3.4.14 of the LRA that the tornado vents (TVs) are within the scope of license renewal because of their pressure equalization intended function. The TVs prevent the collapse of safety-related structures by failing before the structure can become pressurized. The staff reviewed Unit 2 FSAR Section 3.3, "Wind and Tornado Loadings, to verify that the TV system does not have intended functions other than the pressure equalization intended function. In addition, the staff verified that all components supporting the pressure equalization intended function were identified as being within the scope of license renewal.

On the basis of the staff's review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the TV system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information provided in the LRA, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components on the list of components as being subject to an AMR in Table 2.3.4-14 of the LRA. Figure 3.3-1 in the Unit 2 FSAR provides a diagram of the tornado vent structural grill system. The staff identified two components in the diagram that are not listed in LRA Table 2.3.4-14 as being subject to an AMR: the tornado vent concrete curb and the tornado vent grill. In RAI 2.3.4-TV-1 the staff asked the applicant to explain the functions of these components and the bases for excluding them from aging management review. The applicant responded that the concrete curb is within scope and is addressed as part of the reactor building in Tables 2.4.5-1 and 3.3.1-5 of the LRA. The applicant further stated that the function of the vent grill is primarily to prevent debris from falling into the spent fuel pool. The vent grill does not perform an intended function. After reviewing the applicant's response, the staff found the response acceptable. The staff verified

that the passive, long-lived components identified in Section 2.3.4.14 appeared on the list of components subject to an AMR in Table 2.3.4-14. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the TV system subject to an AMR.

<u>Traveling Water Screens/Trash Racks</u>

The applicant provided evaluation boundary diagrams DL-11001 and HL-21033 of the traveling water screens/trash racks and identified the mechanical components subject to an AMR and their functions. The applicant highlighted the detailed flow diagrams to identify those portions of the traveling water screens/trash racks system within the scope of license renewal. The applicant highlighted those components which, they believe, perform at least one intended function meeting the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the descriptions in the Unit 2 FSAR Section 9.2.1.2 to ensure they were representative of the traveling water screens/trash racks system. The staff verified that the components not highlighted did not perform any intended functions meeting the requirements of 10 CFR 54.4.

On the basis of a review of the LRA and supporting information in the FSAR, the staff has reasonable assurance that all portions of the traveling water screens/trash racks system with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information on the flow diagrams for the traveling water screens/trash racks system, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components on the list of components as subject to an AMR. The staff verified that the passive, long-lived components highlighted on the flow diagrams appeared on the list of components subject to an AMR for the traveling water screens/trash racks system. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the traveling water screens/trash racks system subject to an AMR.

2.3.4.2 Conclusion

On the basis of the staff's review of the information presented in Section 2.3.4 of the LRA, the supporting information in the Plant Hatch FSAR, and the applicant's response to the staff's RAIs, and pending satisfactory resolution of Open Items 2.3.3.2-1, 2.3.3.2-2, and 2.3.4.2-1, the staff did not find any omissions by the applicant and, therefore, concludes that there is reasonable assurance that the applicant adequately identified those portions of the auxiliary systems and their associated (supporting) structures and components that fall within the scope of license renewal and are subject to an AMR, in accordance with
10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

2.3.5 Steam and Power Conversion Systems

In Section 2.3.5, "Steam and Power Conversion Systems," of the Plant Hatch LRA, the applicant described the components of the electro-hydraulic control (EHC) system and the main condenser system that are within the scope of license renewal and subject to an AMR. The staff

reviewed these sections of the LRA to determine whether there is reasonable assurance that the applicant has identified all of the SSCs that are within the scope of license renewal, as required by 10 CFR Part 54.4(a), as well as all of the structures and components that are subject to an AMR, as required by 10 CFR Part 54.21(a)(1).

2.3.5.1 Summary of Technical Information in the Application

Electro-Hydraulic Control System

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

The initial scoping, performed by the applicant and based on the functions, has determined that intended function N32-02, Main Turbine Pressure Regulators, is within the scope of license renewal for the EHC system. The main turbine pressure regulator function controls turbine control valve position by adjusting EHC pressure based on main steam pressure. The EHC regulators that are within the scope of license renewal are 1N11-N042A/B and 2N32-N301A/B. Transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator. The associated piping and valve bodies are listed in Table 2.3.5-1 of the LRA as being within the scope of license renewal and subject to an AMR. The component function for the identified piping and valve bodies is the pressure boundary.

Main Condenser System

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

The main condenser system is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 5.66×10^9 Btu/h, an inlet water temperature of 90 °F, and an average back pressure of 3.5 in. Hg absolute. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several others flows, such as exhaust steam from the feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents. Other flows occur periodically. These originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate. During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge from feedwater heater shells, steam-seal regulator, and various steam supply lines.

The initial scoping, performed by the applicant and based on the functions, has determined that the post-accident radioactive decay holdup function (N61-03) of the main condenser system is the intended function within the scope of license renewal. The main condenser system provides a method for main steam isolation valve (MSIV) leakage treatment. It uses the main steam drain lines to convey the MSIV leakage during post-accident conditions to the isolated main condenser. The main condenser provides holdup and allows “plate-out” of the fission products that may leak out from the closed MSIV during post-accident conditions. MSIV leakage that enters the condenser is ultimately released to the turbine building as noncondensible gases through the low-pressure turbine seal after significant plate-out of iodine. This function applies to Unit 2 only.

The associated piping, valve bodies, bolting, condenser shell, preheater, orifices, strainer, and thermowell are identified in LRA Table 2.3.5-2 as being subject to an AMR. The component functions of the valve bodies is pressure boundary, and the functions of all other components are pressure boundary and fission product barrier.

2.3.5.2 Staff evaluation

The staff reviewed the information submitted by the applicant to verify that the applicant has identified the intended functions of the steam and power conversion system that are within the scope of license renewal, and the components that are subject to an AMR, in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

The applicant identified and listed the components that are subject to an AMR for the steam and power conversion system in Tables 2.3.5-1 and 2.3.5-2 of the LRA using the screening methodology described in Sections 2.1.2 and 2.1.3 of the LRA. The screening methodology is evaluated by the staff in Section 2.1 of this SER.

The staff reviewed Plant Hatch Unit 1 FSAR Section 11.2 and Unit 2 FSAR Sections 10.1, 10.2A.1, and 10.4.1 to determine if there were any system functions that were not identified as intended functions in accordance with requirements of 10 CFR 54.4. The staff then reviewed the evaluation boundary drawings (HL-11601, HL-11602, HL-21012, HL26000, HL-21012, HL-21031, HL-21046, HL-21056, HL21205, and HL-26045) to verify that the applicant identified of all the components that are within the scope of license renewal in accordance with 10 CFR 54.4. Further, the staff verified the accuracy of the drawings and the completeness of Tables 2.3.5-1 and 2.3.5-2 by sampling the components adjacent to, but outside, the highlighted portion of the system to verify that all of the components that are within the scope of license renewal were included in the application. In addition, the staff sampled the components that are within the scope of license renewal, but not subject to an AMR, to verify that all of the components that meet the requirements of 10 CFR 54.21(a)(1) were identified as being subject to an AMR.

After the initial review, in a letter dated July 14, 2000, the staff identified areas where additional information was needed to complete its safety review. The applicant responded to the RAIs in a letter dated August 29, 2000.

In reviewing Section 2.3.5 of the LRA, the staff found that this section, which is entitled “Steam and Power Conversion Systems,” describes only the EHC and main condenser systems. The

main steam and feedwater systems, which are also included in the Plant Hatch steam and power conversion systems, are not described in the LRA. This is inconsistent with the description in Plant Hatch Unit 2 FSAR Section 10.1, which states that portions of the main steam and feedwater systems provide safety functions. These portions meet the requirements of 10 CFR 54.4 and, as such, should be within the scope of license renewal. In response to RAI 2.3.5-SPCS-1, the applicant stated that LRA scoping is based on functions. The only in-scope function performed by the feedwater system and main steam system is captured in function B21-02, reactor coolant pressure boundary, which is described in Section 2.3.1.2 of the LRA. The steam and power conversion systems at Plant Hatch only include piping downstream of the MSIVs. The staff's scoping review of these safety-related portions of the main steam and feedwater systems is discussed in Section 2.3.2, "Reactor Coolant System," of this SER. The staff finds the applicant's response to this RAI acceptable.

Electro-Hydraulic Control System

In RAI 2.3.5-EHC-1, the staff noted that four EHC regulators, identified in Section 2.3.5.1 of the LRA as being within scope, could not be located on the boundary drawings. The RAI requested that the applicant identify the EHC regulators (1N11-N042A/B and 2N32-N301A/B) in the boundary drawings. In response, the applicant clarified the locations on the boundary drawings for the two Unit 1 regulators (drawing No. HL-11601), as well as for the two Unit 2 regulators (drawing No. HL-21012). However, the applicant indicated that there was an error on drawing HL-11601, in that it identified two separate components with the same identifying number (N11-N042B). Based on the additional information, the staff was able to find these four regulators in the drawings as stated. By letter dated January 31, 2001, the applicant provided revised drawing HL-11601 that corrected the component identification error. The staff finds this acceptable.

Section 2.3.5.1 of the LRA states that transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator. In the referenced FSAR Sections (Section 11.2 for Unit 1, and Section 10.2A.1 for Unit 2), the staff found the information about the turbine overspeed protection function, but nothing about the "downscale failure of the inservice regulator." In RAI 2.3.5-EHC-2, the staff requested that the applicant explain the event of a "downscale failure of the inservice regulator" and the involvement of the EHC and associated components in the event. In response, the applicant stated that Unit 2 FSAR Section 15.2.3.8 discussed the event of the "downscale failure of the inservice regulator," but called it "Pressure Regulator Failure - Closed." If the controlling regulator fails in the closed position, the backup regulator takes control of the turbine admission valves, preventing a serious transient. The event is only significant if the regulator fails closed without an operable backup regulator. Only the regulators and the piping and valves from the main steam piping to the regulators are needed for this function. The applicant stated that the main function of the EHC system is turbine control, which is not within the scope of license renewal. Furthermore, in a telephone conference on September 13, 2000, the applicant clarified that these regulators are instruments, which are active components (per the guidance in NEI 95-10) and therefore, are not subject to an AMR. On the basis of the information provided in the RAI response and the telephone conference on September 13, 2000, the staff concludes that the applicant has adequately clarified the nature of the "downscale failure of the inservice regulator."

Main Condenser System (Unit 2 Only)

In RAI 2.3.5-MC-1, the staff asked the applicant to explain the reason why the intended function of post-accident radioactive decay holdup (N61-03) for the main condenser system is not applicable for Unit 1. In response, the applicant stated that the licensing basis of the MSIV leakage control for Unit 1 and Unit 2 is different. Unit 1 was built and licensed without an MSIV leakage control system. Unit 2 was originally licensed with an MSIV leakage control system, but the MSIV leakage control system of Unit 2 was subsequently removed, with NRC approval, based on a commitment to include a portion of the Unit 2 condenser and associated piping as the radioactive decay holdup boundary for performing the MSIV leakage control function. Therefore, the intended function is not applicable for Unit 1. On the basis of the information provided in the RAI response, the staff concludes that the post-accident radioactive decay holdup function is applicable to Unit 2 only.

2.3.5.3 Conclusion

On the basis of the staff's review of the information presented in Section 2.3.5 of the LRA, the supporting information in the Plant Hatch FSAR, the applicant's responses to the staff's RAIs, and the additional information provided in telephone conversations between the applicant and the staff, and the letter dated January 31, 2001, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the steam and power conversion systems that are within the scope of license renewal, as required by 10 CFR 54.4(a), and subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures and Structural Components

2.4.1 Introduction

The applicant described the structures and structural components that are within the scope of license renewal and subject to an AMR in the following sections of the LRA: 2.4.1, "Piping Specialties"; 2.4.2, "Conduits, Raceways, and Trays"; 2.4.3, "Primary Containment"; 2.4.4, "Fuel Storage"; 2.4.5, "Reactor Building"; 2.4.6, "Drywell Penetrations"; 2.4.7, "Reactor Building Penetrations"; 2.4.8, "Turbine Building"; 2.4.9, "Intake Structure"; 2.4.10, "Yard Structures"; 2.4.11, "Main Stack"; 2.4.12, "EDG Building"; and 2.4.13, "Control Building." The staff reviewed these sections of the LRA to determine whether there is reasonable assurance that all SSCs have been identified as being within the scope of license renewal, as required by 10 CFR Part 54.4(a), and that all structures and components subject to an AMR have been identified as required by 10 CFR Part 54.21(a)(1).

2.4.2 Summary of Technical Information in the Application

<u>Conduits, Raceways, and Trays</u>

LRA Section 2.4.2 provides a description of the extent to which conduits, raceways, and trays are within the scope of license renewal and subject to an AMR. The purpose of conduits, raceways, and trays is to provide support for cables and penetrations that are selected, routed, and located to prevent a loss of function of any system due to a cable failure in order to ensure survivability during design basis events.

The applicant listed two intended functions for conduits, raceways, and trays. The first is function number R33-01, “Wire and Cable Integrity.” This intended function is performed by conduits, raceways, and trays that are mounted seismic Category I. Conduits, raceways, and trays performing this intended function are considered safety-related. Seismic Category I conduits, raceways and trays provide support for essential cable feeding power supplies and controls. The second intended function is number R33-02, “Wire and Cable Integrity - Non-safety-related.” This intended function is performed by conduits, raceways and trays that are not mounted seismic Category I or seismic Category II/I and are considered nonsafety-related. Nonsafety-related conduits, raceways and trays provide support for non-essential cable feeding power supplies and controls. Also, some nonseismic raceways are included in safe shutdown pathways.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified cable trays and supports as passive and long-lived components which require AMRs. The following component types were identified as being subject to an AMR in Table 2.4.2-1 of the LRA: cable trays and supports (carbon steel, galvanized steel, and aluminum). The applicant identified maintaining the structural support and non-safety-related structural support as the functions for these components.

<u>Control Building</u>

LRA Section 2.4.13 describes the basis for including the control building within the scope of license renewal and identifies the components subject to an AMR. The control building houses the common control room for Units 1 and 2 and associated auxiliaries. The building is a reinforced concrete structure with steel framing consisting of the following major, reinforced concrete, structural components.

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

The application lists function number Z29-01, “Equipment Integrity and Personnel Habitability,” as the only intended function for the control building. The control building includes the substructure, foundations, superstructure, walls, floors, and roof necessary to maintain equipment integrity and personnel habitability. The control building is designed as a seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomenon. Access doors are addressed separately under function number L48-01, “Containment Integrity”.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.13-1 of the LRA: anchors and bolts, blowout panels, miscellaneous steel, reinforced concrete, and structural steel. The applicant

identified five component functions supporting the control building intended function for these component types. These component functions are: structural support, nonsafety-related structural support, missile barrier, fission product barrier, and shelter/protection.

Drywell Penetrations

LRA Section 2.4.6 describes the extent to which drywell penetrations are within the scope of license renewal and subject to an AMR. Drywell penetrations provide a path for cable currents/signal transmissions to pass through primary containment to support various operating modes of associated systems while maintaining the integrity of the primary containment. The general category of containment penetrations includes both electrical penetration assemblies as well as the mechanical penetrations. However, mechanical penetrations, which serve a similar function for mechanical piping penetrations as the electrical penetrations covered in this section, are covered under Section 2.4.3 of the LRA. Electrical penetrations are hermetically sealed penetrations which are welded to the primary containment shell plate. They are designed to maintain primary containment pressure integrity during all postulated operating and accident conditions. Accordingly, they are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

The application lists function number T52-01, “Primary Containment Integrity,” as the only intended function for drywell penetrations. The penetrations maintain containment integrity while providing a free path for cable currents/signals to pass through primary containment. These signals support the various modes of operation of the systems associated with the cables.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified structural steel as the passive and long-lived component requiring an AMR in Table 2.4.6-1 of the LRA. The applicant identified fission product barrier as the function of this component type.

EDG Building

LRA Section 2.4.12 describes the basis for including the emergency diesel generator (EDG) building within the scope of license renewal and identifies components subject to an AMR. The EDG building houses the EDGs and their accessories. The EDGs and their accessories are essential for safe plant shutdown for both Unit 1 and Unit 2. The EDG building is a reinforced concrete structure consisting of the following major reinforced concrete structural components:

- foundation mat,
- exterior walls and interior walls, and
- roof and parapet wall.

The EDG building includes labyrinth access openings for protection against tornado missiles. The building is designed as a seismic Category I structure because it protects vital equipment and systems both during and following the most severe natural phenomena.

The application lists function number Y39-01, “EDG and Equipment Integrity,” as the only intended function for the EDG building. In performing this intended function, the EDG building provides support for the EDGs and their accessories and protects the equipment integrity for the EDGs. The EDGs provide essential ac power.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.12-1 of the LRA: anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel. The applicant identified four component functions supporting the EDG building intended function for these component types. These component functions are: structural support, non-safety-related structural support, missile barrier and shelter/protection.

Fuel Storage

LRA Section 2.4.4 provides a description of the extent to which the fuel storage system is within the scope of license renewal and is subject to an AMR. The fuel storage system provides specially designed underwater storage space for the spent-fuel assemblies which require shielding during storage and handling. The fuel storage facility is located inside the secondary containment on the refueling floor, and includes the following components: the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components.

The application lists two intended functions for the fuel storage system. The first is function number T24-01, “Spent Fuel Integrity.” This intended function is performed by the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components. The fuel storage facility provides specially designed underwater storage space for the spent fuel assemblies which require shielding and cooling during storage and handling. The second intended function is number T24-02, “New Fuel Integrity.” This intended function is performed by the concrete vault and fuel racks. The portion of the fuel storage facility provides specially designed dry, clean storage areas for the new fuel assemblies.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components which require AMRs in Table 2.4.4-1 of the LRA: anchors/bolts (carbon and stainless steel), miscellaneous steel, reinforced concrete, seismic restraints for the spent fuel storage racks, storage racks, and structural steel. The applicant identified four functions for these components: structural support, non-safety-related structural support, shelter/protection and fission product barrier.

Intake Structure

LRA Section 2.4.9 describes the basis for including the plant service water system intake structure within the scope of license renewal and for identifying its components as subject to an AMR. The intake structure protects both the residual heat removal service water and plant

service water equipment from the influence of adverse environmental conditions such as flooding, earthquakes, and tornadoes. Constructed of concrete and steel, the intake structure consists of the following major structural components:

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

The intake structure is shared commonly by both units. Labyrinth access openings protect the intake structure from tornado missiles.

The application lists function number W35-01, “RHRSW and PSW System Integrity,” as the only intended function for the intake structure. The purpose of the intake structure is to prevent the influence of environmental conditions (e.g., flooding, earthquake, and tornadoes) from adversely impacting equipment essential for plant shutdown. The intake structure is a seismic Category I structure.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.9-1 of the LRA: anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel. The applicant identified six component functions supporting the intake structure intended function for these component types. These component functions are: structural support, nonsafety-related structural support, shelter/protection, flood barrier, missile barrier, and flow direction.

<u>Main Stack</u>

LRA Section 2.4.11 describes the basis for including the main stack within the scope of license renewal and for identifying components subject to an AMR. The main stack supports and protects monitoring equipment and provides for the monitoring and elevated release of gaseous waste. The main stack is a cylindrical concrete structure consisting of the following major reinforced concrete components:

- the foundation mat supported on steel “H” piles,
- the truncated conical cylinder stack structure,
- the internal floors, and
- the loading bay consisting of concrete base slab, external and internal walls, and roof.

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

The application lists function number Y32-01, “Gaseous Effluent Elevated Release,” as the only intended function for the main stack. In performing this intended function, the main stack houses equipment for monitoring gaseous effluent releases and assures elevated release of these gaseous wastes to the environment.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.11-1 of the LRA: anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel. The applicant identified five component functions supporting the main stack intended function for these component types. These component functions are: structural support, nonsafety-related structural support, fission product barrier, radiation shielding, and shelter/protection.

Piping Specialties

LRA Section 2.4.1 provides a description of the extent to which structural piping supports are within the scope of license renewal and subject to an AMR. Piping specialties provide support for essential piping systems. The application defines “essential piping systems” as those required to maintain the integrity of safety-related and nonsafety-related systems during normal operations and transient/accident mitigation. Section 2.4.1 also states that the “piping specialties” category of components also includes such components as snubbers and pipe restraints, regardless of the associated system supported, as well as non-ASME HVAC duct supports and tube trays.

The applicant listed two intended functions for piping specialties. The first is function number L35-01, “Pipe Supports.” This intended function is performed by all safety-related plant pipe supports, pipe restraints, and tubing supports. These pipe supports are provided for the reactor coolant system and subsystems to ensure pressure retaining capability of the piping systems due to weight, seismic, and fluid dynamic loads. Pipe supports maintain the integrity of nonsafety functions during accident and seismic events. The second intended function is number L35-02, “Nonseismic Pipe Supports.” This intended function is performed by pipe supports on nonsafety-related piping (nonseismic category) located throughout the plant. These supports are designed for dead weight and thermal loads only. They are not designed for seismic loads. Section 2.4.1 of the LRA states that all seismic category II supports are excluded from the scope of license renewal, unless they are required to support function numbers X43-04 (Plant Wide Fire Suppression With Water), W33-03 (Screen Wash Isolation), and N61-03 (Post Accident Radioactive Decay Holdup).

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified pipe supports, tube trays, and covers as passive and long-lived components which require AMRs. The following three component types were specifically identified as being subject to an AMR in Table 2.4.1-1 of the LRA:

- hangers and supports for ASME Class I piping
- hangers and supports for non ASME Class I piping, tubing and ducts
- tube trays and covers

The applicant identified maintaining structural support as the component function supporting the piping specialties intended functions for these component types.

Primary Containment

LRA Section 2.4.3 provides a description of the primary containment and its intended function which places it within the scope of license renewal and subject to an AMR. The purpose of the primary containment is to isolate and contain fission products released from the reactor primary system following a design basis accident (DBA) and to confine the postulated release of radioactive material. The primary containment is a pressure suppression containment design which consists of a drywell, a pressure suppression chamber (torus) which stores a large volume of water (the suppression pool), a connecting vent system between the drywell and the pressure suppression pool, isolation valves, vacuum relief system, containment cooling systems, and other service equipment. The drywell houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the reactor primary system. The pressure suppression chamber is a steel, torus-shaped pressure vessel located below the drywell. The torus is approximately 107 ft in its outer diameter and has a cross-sectional diameter of approximately 28 ft. The primary containment is designed so that seismic loadings are transmitted by the suppression chamber to the reinforced concrete foundation slab of the reactor building. The suppression chamber is designed so that it can be inspected from the outside.

The applicant provided nine evaluation boundary drawings for Unit 1 and seven drawings for Unit 2 that had intended function designations marked on the drawing to indicate piping that is within the scope of license renewal because of the torus/drywell function (T23-01) intended function. These drawings are HL-16013, HL-16015, HL-16024, HL-16060, HL-16135, HL-16173, HL-16176, HL-16286, HL-16561, HL-26016, HL-26026, HL-26042, HL-26047, HL-26057, HL-26058, and HL-26993. The applicant lists T23-01, “Torus/Drywell,” as the only intended function for the primary containment. The intended function of the primary containment system is to limit the release of fission products in the event of a postulated DBA so that offsite doses do not exceed 10 CFR Part 100 guidelines. The pressure suppression pool initially serves as a heat sink for any postulated transient or accident condition in which the normal heat sink (main condenser or shutdown cooling system) is unavailable.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components which require AMRs in Table 2.4.3-1: anchors/bolts, blind flanges, containment isolation valves (carbon and stainless steel), containment penetrations (mechanical), miscellaneous steel, piping (carbon and stainless steel), reinforced concrete, steel bellows. structural steel, tubing, unreinforced concrete, vent pipe, vent header, and downcomers. The applicant identified several functions for these components including structural support, nonsafety-related structural support, fission product barrier, radiation shielding, pipe whip restraint, flood barrier, shelter/protection, missile barrier, high energy/moderate energy (HE/ME) shielding, and heat exchange.

Reactor Building

LRA Section 2.4.5 describes the extent to which the reactor building is within the scope of license renewal and subject to an AMR. The purpose of the reactor building is to shelter and support the refueling and reactor servicing equipment, new and spent fuel storage facilities, and

other reactor auxiliary and service equipment. The building is a reinforced concrete structure with a steel superstructure consisting of the following major reinforced concrete structural components:

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

The reactor building also completely houses the primary containment system, as well as the core standby cooling systems, reactor water cleanup demineralizer system, standby liquid control system, control rod drive system, reactor protection system, and electrical equipment components. The building is designed for minimum leakage to ensure the capability of the standby gas treatment system to reduce and hold the reactor building at a subatmospheric pressure under normal wind conditions.

The application lists intended function number T29-01, “Containment and Support,” as the only intended function for the reactor building. The reactor building provides primary containment during reactor refueling and maintenance operations. During these conditions, the primary containment may be open. When the primary containment is functional, the reactor building also provides an additional barrier to fission product release. Therefore, it is relied on to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines. This evaluation includes the blowout panels in the pipe-chase between the reactor building and the turbine building.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components which require AMRs in Table 2.4.5-1 of the LRA: anchors/bolts, blowout panels, miscellaneous steel, panel joint seals and sealants, reinforced concrete, and structural steel. The applicant identified various functions for these components, including structural support, nonsafety-related structural support, HE/ME shielding, flood barrier, radiation shielding, missile barrier, shelter/protection and fission product barrier.

<u>Reactor Building Penetrations</u>

LRA Section 2.4.7 describes the basis for including reactor building penetrations within the scope of license renewal and for identifying components subject to an AMR. The purpose of the reactor building penetrations is to allow mechanical and electrical equipment and personnel to pass through secondary containment to support plant operations while maintaining secondary containment integrity within design limits. As noted in LRA Section 2.4.5, the reactor building provides a barrier to fission product release when the primary containment is open (e.g., for refueling or maintenance operations).   Penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

The application lists function number T54-01, “Secondary Containment Integrity,” as the only intended function for reactor building penetrations. In performing this intended function, reactor building electrical and mechanical penetrations maintain secondary containment leakage rates within design limits while allowing piping and conductors to penetrate the secondary containment boundary. The applicant stated that this function also includes the structural support feature of Nelson Frames. The electrical aspect of Nelson Frames is included as part of Electrical Screening (refer to LRA Table 2.5.15-1.) and is evaluated in Sections 2.5 of this SER.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified structural steel (galvanized and carbon steel) as the passive and long-lived component requiring an AMR in Table 2.4.6-1 of the LRA. The applicant identified fission product barrier as the function of this component type.

Turbine Building

LRA Section 2.4.8 describes the basis for including the turbine building within the scope of license renewal and identifies the components subject to an AMR. The turbine building houses the turbine-generator and associated auxiliaries, such as the condensate and feedwater systems. Constructed of steel and concrete, the turbine building consists of the following major, reinforced concrete, structural components:

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

The turbine building does not house any equipment or instrumentation that would preclude the ability to shut down the reactor safely if damaged from a high-energy line failure. The turbine building is designed and constructed to ensure that it will not damage Category I structures or equipment located inside or adjacent to it in the event of a design basis event (DBE).

The application lists function number U29-01, “BOP [Balance of Plant] Equipment Integrity and Support,” as the only intended function for the turbine building. This intended function places portions of the turbine building within the scope of license renewal. Specifically, the cable chase area below elevation 147 ft is designed to seismic Category I criteria. A seismic Category I barrier is located between the main steam and feedwater piping above the 147 ft elevation and the cable chase area below. This barrier prevents the postulated failure of the main steam or feedwater piping in the turbine building from adversely affecting the cables below. These cables provide trip inputs for the recirculation pump trip and reactor scram following either a generator load rejection or turbine trip originating in the turbine building. On the basis of these considerations, the portions of the Unit 1 turbine building and the cable chase area below elevation 147 ft are within the scope of license renewal. Similarly, the portions of the Unit 2 turbine building and the cable chase area below elevation 147 ft are also within scope, as are the supports over the radioactive release pathway for the main condenser.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.8-1 of the LRA: anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel. The applicant identified four component functions supporting the turbine building intended function for these component types. These component functions are: structural support, nonsafety-related structural support, shelter/protection, and radiation shielding.

<u>Yard Structures</u>

LRA Section 2.4.20 describes the basis for including yard structures in the scope of license renewal and identifies the components subject to an AMR. Yard structures provide structures for maintaining equipment integrity and personnel habitability on the plant site. Some of the structures included in this category of structures are:

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

The application lists function number Y29-01, “Equipment Integrity and Personnel Habitability,” as the only intended function for yard structures. In performing this intended function, the yard structures provide for equipment integrity and personnel habitability within the various structures listed above. For instance, the liquid nitrogen tank foundation is within the scope of license renewal because the foundation is seismic Category I, thus ensuring the integrity of the nitrogen tank during a seismic event. The liquid nitrogen tank provides the safety-related back-up supply of motive gas for the drywell inerting system and the drywell pneumatic system, and is relied upon in certain safety analyses described in the FSAR. In addition, the liquid nitrogen tank is relied upon to achieve safe shutdown in the event of a fire. Similarly, the enclosure around the condensate storage tank (CST), the wall and the CST foundation are also seismically qualified to Category 1 requirements to ensure the functionality of the CST during a seismic event. The service water valve boxes are within the scope of license renewal because they contain piping for the plant service water system that is also within the scope of license renewal. As stated above, the concrete duct runs and pull boxes that traverse the yard between various Class I structures and the turbine building are also within the scope of license renewal. These duct runs provide protection for safety-related circuits routed through them. The foundations for the fire pump house, fire protection water storage tanks, and fire protection diesel pump fuel tanks are also within the scope of license renewal.

The applicant described its process for identifying the structural/civil components within the scope of license renewal and subject to an AMR in Section 2.1.3 of the LRA. On the basis of this methodology, the applicant identified the following component types as the passive and long-lived components requiring an AMR in Table 2.4.10-1 of the LRA: anchors and bolts, pull box cover plates, miscellaneous steel, reinforced concrete, and structural steel. The applicant

identified four component functions supporting the yard structure intended function for these component types. These component functions are: structural support, nonsafety-related structural support, shelter/protection, and flood barrier.

2.4.3 Staff Evaluation

Conduits, Raceways, and Trays

The applicant stated in Section 2.4.2 of the LRA that conduits, raceways and trays are within the scope of license renewal because of their wire and cable integrity intended functions. Conduits, raceways and trays ensure the integrity of safety-related cables to survive a design basis event. Seismic Category I conduits, raceways and trays are considered safety-related. The staff reviewed the application and FSAR Sections 8.8 (Unit 1) and 8.3 (Unit 2) to verify that the conduits, raceways and trays do not have intended functions other than the cable integrity intended functions listed in the application. In addition, the staff verified that all components supporting the cable integrity intended functions were identified as being within the scope of license renewal.

The staff reviewed the LRA and supporting information in the FSAR, and identified one RAI which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-CRT-1 primarily related to defining the boundaries of conduits, raceways and trays that are considered to be within the scope of license renewal by the applicant. Since the applicant did not provide drawings to show which conduits, raceways and trays are considered to be within the scope of license renewal, the staff requested clarification as to the boundaries defining which conduits, raceways and trays are within the scope of license renewal and those that are not within scope. In its August 29, 2000, response to the staff's RAI, the applicant provided the following additional information to clarify the boundaries of conduits, raceways and trays considered to be within the scope of license renewal:

> "Except for nonsafety-related conduits, raceways and trays and their supports (R33-02) that are not located within in-scope buildings and structures, all conduits, raceways and trays with the intended functions R33-01 (safety-related) and the remaining R33-02 (nonsafety-related) components are in scope for license renewal."

Thus, intended functions R33-01 (wire and cable integrity) and R33-02 (wire and cable integrity/non-safety-related) include the following within the scope of license renewal:

- all safety-related conduits, raceways and trays regardless of location, and
- all nonsafety-related conduits, raceways and trays that are located in buildings or structures that are within the scope of license renewal.

The staff finds this to be acceptable. On the basis of the staff's review of the application and the applicant's RAI response, the staff concludes that there is reasonable assurance that the applicant has identified all portions of conduits, raceways and trays with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4-2 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the conduits, raceways, and trays SCs that are subject to an AMR in Table 2.4-2.

Control Building

The applicant stated in Section 2.4.13 of the LRA that the control building is within the scope of license renewal because of its equipment integrity and personnel habitability intended function. The staff reviewed the application and FSAR Sections 12.3.3 1.1 (Unit 1) and 3.2.1 (Unit 2) to verify that all control building intended functions are identified in the application. In addition, the staff verified that all components supporting the control building intended function are identified as being within the scope of license renewal.

On the basis of the staff's review of the application and information in the FSAR, the staff concludes that there is reasonable assurance that applicant has identified all portions of control building with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.13-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the control building SCs that are subject to an AMR in Table 2.4.13-1.

Drywell Penetrations

The applicant stated in Section 2.4.6 of the LRA that the drywell penetrations are within the scope of license renewal because of their primary containment integrity intended function. In this section of the LRA, the applicant is referring to electrical penetrations only. Mechanical system penetrations are covered with the primary containment in Section 2.4.3 of the LRA. The drywell penetrations discussed in Section 2.4.6 provide a path for cable currents and signals to pass through the primary containment boundary to support operation of the various plant systems. The staff reviewed the application and Unit 1 FSAR Section 5.2 and Unit 2 FSAR Section 6.2.1 to verify that the drywell penetrations do not perform intended functions beyond the primary containment integrity intended function listed in the application. In addition, the staff verified that all components supporting the drywell penetration intended function were identified as being within the scope of license renewal.

The staff reviewed the LRA and supporting information in the FSAR, and issued an RAI related to this section which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-1 requested the applicant to provide clarifying information (either drawings or written description) to define the boundaries of drywell penetrations that are within the scope of license renewal. The drywell penetration components subject to an AMR are listed on Table 2.4.6-1 of the LRA. In its August 29, 2000, response to the staff's RAI, the applicant provided no additional information. However, by letter dated January 31, 2001, the applicant clarified that all drywell penetrations are in scope for license renewal. The staff finds this acceptable.

On the basis of the staff's review of the application, the staff concludes that there is reasonable assurance that the applicant has identified all drywell penetrations with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff reviewed the application to determine if the applicant properly identified the penetration components that are passive, long-lived and subject to an AMR. Drywell penetration SCs that are subject to an AMR are identified on the list of components in Table 2.4.6-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the drywell penetration SCs that are subject to an AMR in Table 2.4.6-1.

<u>EDG Building</u>

The applicant stated in Section 2.4.12 of the LRA that the emergency diesel generator (EDG) building is within the scope of license renewal because of its EDG and equipment integrity intended function. The staff reviewed the application and FSAR Sections 12.2.6 (Unit 1) and 9.4.5 (Unit 2) to verify that all EDG building intended functions are identified in the application. In addition, the staff verified that all components supporting the EDG building intended function are identified as being within the scope of license renewal.

In its review of the LRA and supporting information in the FSAR, the staff identified one RAI which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-EDGB-1 primarily related to clarifying information on whether ventilation components for the EDG (both cooling and combustion air) are within the scope of license renewal. EDG building components subject to an AMR are listed on Table 2.4.12-1 of the LRA. The following summarizes the information provided in the applicant's August 29, 2000, RAI response:

- The following components associated with the EDG are within the scope of license renewal: the EDG combustion air intake and exhaust air components (intended function R43-01), and the EDG building ventilation components (intended functions X41-02, X41-03, X41-04, and X41-05). The ventilation components are listed on LRA Table 2.3.4-17. The following combustion components are listed on LRA Table 2.3.4-12: filter housing, carbon steel piping, and galvanized steel piping.

The staff finds the applicant's RAI response to be acceptable. On the basis of the staff's review of the application and the applicant's RAI response, the staff concludes that there is reasonable assurance that applicant has identified all portions of EDG building with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the applicant's RAI response, and the FSAR, the staff sampled components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.12-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the EDG building SCs that are subject to an AMR in Table 2.4.12-1, or in other appropriate sections of the LRA.

Fuel Storage

The applicant stated in Section 2.4.4 of the LRA that the fuel storage system is within the scope of license renewal because of its spent and new fuel integrity intended functions. The fuel storage system ensures the integrity by providing safe storage either under water for spent fuel or in dry storage for new fuel. The staff reviewed the application and Unit 1 FSAR Sections 10.2 and 10.3, and Unit 2 FSAR Section 9.1 to verify that the fuel storage system does not have intended functions beyond the fuel integrity intended functions listed in the application. In addition, the staff verified that all components supporting the fuel integrity intended functions were identified as being within the scope of license renewal.

The staff reviewed the LRA and supporting information in the FSAR, and identified three RAIs which were forwarded to the applicant by letter dated July 14, 2000. RAIs 2.4-FS-1, 2.4-FS-2, and 2.4-FS-3 primarily related to clarifying information on the fuel storage system components subject to an AMR listed on Table 2.4.4-1 of the LRA. Since the applicant did not provide drawings to show which SCs are considered to be within the scope of license renewal, the staff requested clarification as to the boundaries defining which SCs are subject to an AMR. In its August 29, 2000, response to the staff's RAIs, the applicant provided the following additional information and clarifications:

- The new fuel storage racks are made of aluminum. The spent fuel storage racks are made of stainless steel and include Boral as a neutron absorber material. These racks were identified as Structural Steel in Table 2.4.4-1.

- The spent fuel storage racks are credited in maintaining the stored spent fuel subcritical under all normal and abnormal storage configurations. The Boral plates are used as a neutron absorber. Therefore, reactivity control is an intended function of the Boral plates.

- The term "other equipment" used in the application in describing the boundaries of SCs that perform the intended function T24-01 (spent fuel integrity) includes items such as miscellaneous embedded steel, anchors and bolts, and a leak chase system. These items also contribute to the maintenance of the integrity of the spent fuel pool to meet its intended function.

On the basis of its response to the staff's RAIs, the applicant provided the following amended information corresponding to the relevant line items in Table 2.4.4-1. The new fuel storage racks and spent fuel storage racks are explicitly identified. Boral was added as a component material and reactivity control was added as a component function for the spent fuel storage racks.

Structural Component	Component Functions	Material
Storage Racks*	New Fuel Structural Support	Aluminum
Storage Racks	Spent Fuel Shelter/Protection; Fission Product Barrier; Structural Support; Reactivity Control	Stainless Steel Boral*
Structural Steel	Shelter/Protection; Fission Product Barrier; Structural Support	Stainless Steel

* No aging effects requiring management"

The staff finds the applicant's RAI responses to be acceptable. On the basis of the staff's review of the application and the applicant's RAI responses, the staff concludes that there is reasonable assurance that the applicant has identified all portions of fuel storage system with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.4-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the fuel storage system SCs that are subject to an AMR in Table 2.4.4-1.

Intake Structure

The applicant stated in Section 2.4.9 of the LRA that the plant service water (PSW)/residual heat removal service water (RHRSW) system intake structure is within the scope of license renewal because of its RHRSW and PSW system integrity intended function. The staff reviewed the application and FSAR Sections 12.2.7 (Unit 1) and 3.8.4, 3.8.5, and 3.8.6 (Unit 2) to verify that all intake structure intended functions are identified in the application. In addition, the staff verified that all components supporting the intake structure intended function are identified as being within the scope of license renewal.

In its review of the LRA and supporting information in the FSAR, the staff identified four RAIs which were forwarded to the applicant by letter dated July 14, 2000. RAIs 2.4-IS-1, 2.4-IS-2, 2.4-IS-3,and 2.4-IS-4 primarily related to clarifying information regarding whether intake structure components have been identified adequately as being within the scope of license renewal. Intake structure components subject to an AMR are listed on Table 2.4.9-1 of the LRA. The following summarizes the new and clarifying information provided in the applicant's August 29, 2000, RAI responses:

- The difference between "miscellaneous steel" and "structural steel" in Table 2.4.9-1 is that structural steel is defined as substructure or superstructure steel that is part of the primary structural support function of a building or structure. Miscellaneous steel is defined as steel which does not perform a primary structural integrity function for a building but does provide secondary structural support for equipment or components

within the building. In some cases, it may provide protection around openings in floors or walls. For the intake structure, structural steel includes steel barriers utilized as water spray barriers and internally generated missile barriers. Miscellaneous steel includes embedded plates and/or frames and anchors used to support the missile or spray shields. The term "flow direction" used in LRA Table 2.4.9-1 is a label described in LRA Table 2.1-2 as "Provide spray shield or curbs for directing flow."

- Coarse trash racks, trash rakes, traveling water screens and stop logs are within the scope of license renewal. Trash rakes and water screens are included in the traveling water screen/trash rack system and stop logs are included in the intake structure. Traveling water screens and trash racks are described in LRA Section 2.3.4.16 and Table 2.3.4-16. Stop logs and steel supports for the trash racks are included in this section (2.4.9) of the LRA. In LRA Table 2.4.9-1, stop logs are included as structural steel components and trash rack supports are included as miscellaneous steel components. Aging management of these components is addressed in Section C.2.6.3 of the LRA.

- The steel sheet piles are not considered to be within the scope of license renewal. The sheet piles were installed to facilitate dewatering of the intake structure excavation and subsequent construction of the intake structure. As described in Section 12.2.7 of the Unit 1 FSAR, the sheet piles provide protection to the intake structure from a direct hit by river traffic or debris flowing across the river channel. However, the FSAR states that the sheet piles could fail and not prevent a safety function. Wood fender piles provide protection to the sheet pile cells by dissipating dynamic effects of moving loads. Impact of debris or river traffic on the sheet piles, wood fender piles, or on the front of the intake structure would not prevent the structure from providing water to the plant service water and RHR service water systems.

- The creosote wall constructed near the intake structure is not considered to be within the scope of license renewal. The FSAR does describe the creosote wall as rerouting river water flow and preventing undercutting of the intake structure. However, based on flow characteristics of the river, and the river channel being located near the north bank and the intake structure being located on the south bank of the river, undercutting of the intake structure is not a credible event requiring protection for the Plant Hatch intake structure. Therefore, the creosote wall was not considered to be in the scope of license renewal.

The staff finds the applicant's RAI responses to be acceptable. On the basis of the staff's review of the application and the applicant's RAI responses, the staff concludes that there is reasonable assurance that applicant has identified all portions of EDG building with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the applicant's RAI responses, and the FSAR, the staff sampled components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.9-1 of the LRA.   No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the EDG building SCs that are subject to an AMR in Table 2.4.8-1, or in other appropriate sections of the LRA.

Main Stack

The applicant stated in Section 2.4.11 of the LRA that the main stack is within the scope of license renewal because of its gaseous effluent elevated release intended function. The staff reviewed the application and FSAR Sections 5.3.4 (Unit 1) and 11.3 (Unit 2) to verify that all main stack intended functions are identified in the application. In addition, the staff verified that all components supporting the main stack intended function are identified as being within the scope of license renewal.

On the basis of the staff's review of the application and supporting FSAR information, the staff concludes that there is reasonable assurance that applicant has identified all portions of the main stack with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.11-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the main stack SCs that are subject to an AMR in Table 2.4.11-1.

Piping Specialties

The applicant stated in Section 2.4.1 of the LRA that piping specialties are within the scope of license renewal because of their piping support intended functions. These piping supports ensure the pressure retaining capability of piping, and are designed to withstand weight, seismic, and fluid dynamic loads. The staff reviewed the application to verify that the piping specialties do not have intended functions other than the piping support intended functions listed in the application. In addition, the staff verified that all components supporting the piping support intended functions were identified as being within the scope of license renewal.

The staff reviewed the LRA and supporting information in the FSAR, and identified several RAIs which were forwarded to the applicant by letter dated July 14, 2000. RAIs 2.4-PS-1, 2.4-PS-2, and 2.4-PS-3 primarily related to defining the boundaries of piping supports that were considered to be within the scope of license renewal by the applicant. Since the applicant did not provide drawings to show which piping specialty components are considered to be within the scope of license renewal, the staff requested clarification as to the boundaries defining which piping supports are within the scope of license renewal and those that are not within scope. In its August 29, 2000, response to the staff's RAIs, the applicant provided the following additional information to clarify the scope of piping supports considered to be within the scope of license renewal:

> "Pipe supports for nonsafety-related piping that ensure the functionality of boundary valves that separate portions of systems required to remain functional during and after a design basis event are included in function L35-01. These supports comprise the group referenced in the second sentence of the L35-01 intended function in section 2.4.1 that states, "[Other] Pipe supports maintain the integrity of nonsafety functions during accident and seismic events." This sentence can be clarified to state that these nonsafety pipe supports, which are

located in Seismic Category I structures, are considered for Seismic II/I criteria to prevent failure of the nonsafety piping system from adversely impacting the ability of a safety system to perform its function. Thus, all pipe supports located in a Seismic Category I structure, regardless if the supports are for safety-related or nonsafety-related systems, are conservatively included in function L35-01 and are in-scope for license renewal. The only Seismic Category II supports not located in a Seismic Category I structure that are included in-scope for license renewal are for functions X43-04, W33-03, and N61-03."

Thus, intended function L35-01 (pipe supports) includes piping supports that are qualified to seismic Category I or seismic Category II/I requirements regardless of system designation. The staff finds this to be acceptable. On the basis of the staff's review of the application and the applicant's RAI responses, the staff concludes that there is reasonable assurance that applicant has identified all portions of piping specialties with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4-1 of the LRA. No omissions were identified. Treatment of piping segments for seismic Category II/I is addressed in Section 2.1.3.1 of this SER. On the basis of this review, the staff has reasonable assurance that the applicant has identified the piping specialty SCs that are subject to an AMR in Table 2.4-1.

Primary Containment

The applicant stated in Section 2.4.3 of the LRA that the primary containment system is within the scope of license renewal because of its intended function to limit the release or fission products during a design basis accident. The staff reviewed the application, FSAR Sections 5.1.2 (Unit 1) and 6.2.1 (Unit 2), and the sixteen drawings provided by the applicant (showing the portions of the primary containment that are within the scope of license renewal) to verify that all primary containment intended functions are identified in the application. In addition, the staff verified that all components supporting the primary containment intended function are identified as being within the scope of license renewal.

The staff reviewed the LRA, the drawings provided by the applicant, and supporting information in the FSAR, and identified two RAIs which were forwarded to the applicant by letter dated July 14, 2000. RAIs 2.4-PC-1 and 2.4-PC-2 primarily related to clarifying information on the primary containment system components subject to an AMR listed on Table 2.4.4-1 of the LRA. The following summarizes the staff's RAIs and the applicant's August 29, 2000, response:

- Unidentified component number D001 located at position G3 on DWG HL-26016 was identified on the drawing as supporting intended function T23-01 (torus/drywell) and as being within the scope of license renewal. The staff could not determine what type of component it was from the legend provided by the applicant. In its RAI response, the applicant stated that this component is a flex hose made of stainless steel and was screened as piping in Table 2.4.3-1 of the LRA. In addition, the applicant stated that the aging management of this component can be found in Section C.2.2.9.2 of the LRA.

- The applicant did not identify the following components as being within the scope of license renewal for the primary containment in drawings referenced for intended function T23-01, even though they do perform a primary containment pressure boundary function: 1) the tubing segment penetrating the primary containment at position B2 on DWG HL-26057, 2) the tubing segment penetrating the primary containment at position A2 on DWG HL-26057, 3) the personnel lock located at position D2 on DWG HL-26057, 4) the two equipment access hatches and the control rod drive removable hatch described in the Unit 2 FSAR Section 3.8.2.1.3, and 5) the traversing in-core probe guide tube penetration described in Unit 2 FSAR Section 3.8.2.1. The applicant was requested to indicate where these components are evaluated for an AMR in the LRA or justify their exclusion from the scope of license renewal. In its RAI response, the applicant stated that tubing segments are routinely identified in the LRA as piping. The specific tubing segments penetrating the primary containment at A2 and B2 on HL-26057 are included in LRA Table 3.3.1-3 as piping (this table links to Section C.2.2.9.2 for the AMR and demonstration). Personnel locks and equipment hatches penetrating containment are identified in LRA Table 2.4.3-1 as intended function T23-01 penetrations. The TIP is included in function C51-03 (traversing incore probe), and is not within the scope of license renewal. However, the TIP guide tube does support primary containment intended function T23-01, and is addressed in Table 2.4.3-1. The penetration for the TIP guide tube is covered under intended function T52-01(primary containment integrity) in Section 2.4.6 of the LRA.

The staff finds the applicant's RAI responses to be acceptable. On the basis of the staff's review of the application and the applicant's RAI responses, the staff concludes that there is reasonable assurance that applicant has identified all portions of the primary containment system with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.3-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the primary containment system SCs that are subject to an AMR in Table 2.4.3-1.

<u>Reactor Building</u>

The applicant stated in Section 2.4.5 of the LRA that the reactor building is within the scope of license renewal because of its intended function to mitigate the consequences of accidents that could result in offsite exposure comparable to the 10 CFR Part 100 guidelines. The staff reviewed the application and FSAR Sections 12.2.1 (Unit 1) and 3.0 (Unit 2) to verify that all reactor building intended functions are identified in the application. In addition, the staff verified that all components supporting the reactor building intended function are identified as being within the scope of license renewal and as being subject to an AMR.

In its review of the LRA and supporting information in the FSAR, the staff identified three RAIs which were forwarded to the applicant by letter dated July 14, 2000. RAIs 2.4-RB-1, 2.4-RB-2, and 2.4-RB-3 primarily related to clarifying information on the boundaries of the reactor building that are within the scope of license renewal as well as clarifying information as to whether certain

components are within the scope of license renewal. Reactor building components subject to an AMR are listed on Table 2.4.5-1 of the LRA. The following summarizes the information provided in the applicant's August 29, 2000, RAI responses:

- The following reactor building structural components are within the scope of license renewal: the refueling water seal assembly, the main steam line enclosure, the reactor pedestal, and the reactor coolant pump supports. The applicant indicated that the refueling water seal assembly is included in Table 2.4.3-1 generically under "Structural Steel," the main steam line enclosure is included in Table 2.4.3-1 under the generic heading of "Concrete," and the reactor pedestal is included in LRA Table 2.4.3-1. The reactor pedestal is made of unreinforced concrete encased in a structural steel frame for Unit 2, and of reinforced concrete for Unit 1. In addition, the lug support attachments at the reactor recirculation pumps are evaluated as part of the pump casing in LRA Table 2.3.2-1 of the LRA. The supports and lug attachments to the structural steel are evaluated in LRA Table 2.4.1-1 as part of hangers and supports for ASME Class 1 piping. The foam glass inserts between buildings, described in Unit 1 FSAR Section 12.2.15.2.2, are not within the scope of license renewal. The foam glass originally maintained a gap between structures during construction so that there can be free movement during an earthquake. After construction of the plant, the foam glass was removed in all areas except below grade between the reactor building and its adjacent structures (control, turbine and radwaste buildings). The foam glass served only as form work for maintaining the gap, and has no intended structural function.

- In general, the LRA includes the whole reactor building, along with all structural components within its boundary, within the scope of license renewal. These components are mostly evaluated under function T29-01 (containment and support). However, several items have been addressed in greater detail in separate sections. For example, these separate sections in the reactor building include SCs with intended functions associated with primary containment (torus/drywell [T23-01]), fuel storage (spent fuel integrity [T24-01] and new fuel integrity [T24-02]), penetrations (primary containment integrity [T52-01] and secondary containment integrity [T54-01]), cranes (reactor building crane [T31-02]), tornado vents (pressure equalization [T38-01]), etc. These SCs were considered separately to facilitate evaluation of the components for specialized loadings, environmental parameters, and/or aging effects.

- In RAI-2.4-RB-3, the staff stated that airlock water stops appear to perform an intended function because they are part of the pressure boundary for the secondary containment. Accordingly, they should be included within the scope of license renewal. The applicant responded that only the three-bulb rubber water stop in the joint between the railroad airlock and the reactor building should have been in the LRA. The applicant stated that the three-bulb water stop is part of the pressure boundary for the secondary containment, does contribute to the intended function, and should have been included in the LRA. The applicant stated that the water stop will be subject to an AMR and the results provided in a subsequent submittal. By letter dated January 31, 2001, the applicant stated that a screening record was prepared for the three-bulb waterstop embedded in the separation joint between the Unit 1 reactor building and the railroad airlock structure. Thus, the three-bulb waterstop has been added to the scope of license renewal. The letter stated that the intended function of this waterstop is to

provide a pressure boundary or a fission product retention barrier to protect public health and safety during any postulated design basis events. The waterstop has been addressed by an AMR.

On the basis of the staff's review of the application and the applicant's RAI responses, as well as the clarifying information provided in the applicant's letter dated January 31, 2001, the staff concludes that there is reasonable assurance that applicant has identified all portions of reactor building with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the applicants RAI responses, and the FSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.5-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the reactor building SCs that are subject to an AMR in Table 2.4.5-1, or in other appropriate sections of the LRA.

Reactor Building Penetrations

The applicant stated in Section 2.4.7 of the LRA that the reactor building penetrations are within the scope of license renewal because of their secondary containment integrity intended function. In this section of the LRA, the applicant is referring to both mechanical and electrical penetrations. The reactor building penetrations discussed in Section 2.4.7 provide a path for mechanical and electrical components and signals, and personnel, to pass through secondary containment to support operating modes of various plant equipment and systems while maintaining secondary containment integrity. The staff reviewed the application and Unit 1 FSAR Section 5.3.3.2 and Unit 2 FSAR Figure 8.3-11 to verify that the reactor building penetrations do not perform intended functions beyond the secondary containment integrity intended function listed in the application. In addition, the staff verified that all components supporting the reactor building penetration intended function were identified as being within the scope of license renewal.

The staff reviewed the LRA and supporting information in the FSAR, and issued an RAI related to this section which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-1 requested the applicant to provide clarifying information (either drawings or written description) to define the boundaries of reactor building penetrations that are within the scope of license renewal. The reactor building penetration components subject to an AMR are listed on Table 2.4.7-1 of the LRA. In its August 29, 2000, response to the staff's RAI, the applicant provided no additional information. However, by letter dated January 31, 2001, the applicant clarified that all external reactor building penetrations are in scope for license renewal. The staff finds this acceptable.

On the basis of the staff's review of the application the staff concludes that there is reasonable assurance that applicant has identified all drywell penetrations with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA and the FSAR, the staff sampled evaluated the application to determine if the applicant properly identified the penetration components that are

passive, long-lived and subject to an AMR. Reactor building penetration SCs that meet are subject to an AMR are identified on the list of components in Table 2.4.7-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the drywell penetration SCs that are subject to an AMR in Table 2.4.7-1.

Turbine Building

The applicant stated in Section 2.4.8 of the LRA that the turbine building is within the scope of license renewal because of its balance of plant equipment integrity and support intended function. The staff reviewed the application and FSAR Sections 12.2.2 (Unit 1) and 3.2 (Unit 2) to verify that all turbine building intended functions are identified in the application. In addition, the staff verified that all components supporting the turbine building intended function are identified as being within the scope of license renewal.

In its review of the LRA and supporting information in the FSAR, the staff identified one RAI which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-TB-1 primarily related to clarifying information on the boundaries of the turbine building that are within the scope of license renewal. Turbine building components subject to an AMR are listed on Table 2.4.8-1 of the LRA. The following summarizes the information provided in the applicant's August 29, 2000, RAI responses:

- The staff identified an apparent discrepancy in the information provided by the applicant. Section 2.4.8 of the LRA states that the turbine building is designed and constructed to ensure it will not damage any seismic Category I structure or equipment located inside or adjacent to it. In addition, cables that are important to safety are located in a seismic Category I chase area within the turbine building. Drawing EL-10173, "General Building Site Plan," indicates that the entire turbine building for Units 1 and 2 is within the scope of license renewal. However, Section 2.4.8 of the LRA indicates only certain portions of the structure are proposed to be included within the scope of license renewal. The applicant was requested to clarify whether the entire turbine building structure for Units 1 and 2 is within the scope of license renewal, or to provide a justification for omitting portions of the turbine building from the scope of license renewal. In its response, the applicant stated that only certain portions of the Unit 1 and 2 turbine buildings meet any of the scoping criteria of the license renewal rule. The turbine buildings are Category II structures. Therefore, failure of either structure will neither result in the release of significant radioactivity nor prevent reactor shutdown. The Unit 1 and 2 turbine buildings, as structures, are only in license renewal scope to the extent that they are nonsafety-related structures that could prevent a safety-related function. That extent is discussed in the following paragraphs.

- A portion of each turbine building was designed to seismic Category I criteria. That portion, described in Unit 1 FSAR Section N.3.2.4, and Unit 2 FSAR Section 15A.3.2.D as the cable chase area below elevation 147 ft, has been included in license renewal scope. As stated in the Unit 1 FSAR Section 12.2.15.2.2, the turbine buildings are designed and constructed to ensure that they will not damage Category I structures or equipment located inside or adjacent to them in the event of a DBE. Thus, the applicant only considered those portions of each turbine building adjacent to Category I structures

or having Category I equipment inside them as within scope. The applicant's assessment also includes the south end of the Unit 1 turbine building up to and including the bay extending north of the Unit 1 reactor building, and the north end of the Unit 2 turbine building up to and including the bay extending south of the Unit 2 reactor building within scope for license renewal. The structural elements included in this scope are the base mat, columns, exterior walls, and roof, as well as the cable chase areas described above.

- The evaluation boundary drawing (EL-10173) depicting the in scope structures shows the entire turbine building in scope for both units. This drawing reflects the practical consideration that the program credited to manage aging effects for the turbine building structural components includes the entire building in its scope. Thus, in practice, any distinction as to the portions of the turbine buildings that are in scope is rendered unnecessary.

The staff finds the applicant's RAI response to be acceptable. On the basis of the staff's review of the application and the applicant's RAI response, the staff concludes that there is reasonable assurance that applicant has identified all portions of turbine building with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the applicants RAI responses, and the FSAR, the staff sampled several components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.8-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the turbine building SCs that are subject to an AMR in Table 2.4.8-1.

Yard Structures

The applicant stated in Section 2.4.10 of the LRA that yard structures are within the scope of license renewal because of their equipment integrity and personnel habitability intended function. The staff reviewed the application and FSAR Sections 5.2.3.9 (Unit 1) and 3.8.5.1 (Unit 2) to verify that all yard structure intended functions are identified in the application. In addition, the staff verified that all components supporting the yard structures intended function are identified as being within the scope of license renewal.

In its review of the LRA and supporting information in the FSAR, the staff identified one RAI which was forwarded to the applicant by letter dated July 14, 2000. RAI 2.4-1 primarily related to clarifying information on what yard structures are within the scope of license renewal. Yard structures components subject to an AMR are listed on Table 2.4.10-1 of the LRA. The following information was provided in the applicant's August 29, 2000, RAI response:

> "Yard structures are addressed in Section 2.4.10 and screening results shown in Table 2.4.10-1. On page 2.4-1 of the application, Section 2.4, the application "[notes] that the intended functions define the boundaries by which various component groups are analyzed for aging management purposes. The system description is informational and is not intended to define boundaries." Not all yard structures are in the scope of license renewal. This is why the application

> refers to "some of the structures" on page 2.4-19. Only the yard structures that support an intended function are included within the evaluation boundaries described on pages 2.4-19 and 2.4-20. Supporting information for the scoping and screening of structures pursuant to both the Rule requirements and the scoping and screening methodology described in the LRA is available at the SNC corporate offices for NRC review."

This response did not adequately provide the information the staff needed to complete its review. Therefore, a telephone conference was held with the applicant on December 28, 2000. In this conference call, the applicant stated that the yard structures listed in Section 2.4.10 of the LRA are the only yard structures with an intended function. Therefore, they are the only yard structures within the scope of license renewal. After further review, the staff did not identify any yard structures with intended functions not on this list, or covered elsewhere in the application. Therefore, the staff finds the applicant's RAI response to be acceptable. On the basis of the staff's review of the application and the applicant's RAI response, the staff concludes that there is reasonable assurance that applicant has identified all portions of yard structures with intended functions meeting the criteria in 10 CFR 54.4(a) as being within the scope of license renewal.

Using the information provided in the LRA, the applicant's RAI response, and the FSAR, the staff sampled components to determine whether the applicant properly identified the passive, long-lived SCs on the list of components as being subject to an AMR in Table 2.4.10-1 of the LRA. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the yard structure SCs that are subject to an AMR in Table 2.4.10-1.

2.4.4 Conclusions

On the basis of the staff's review of the information presented in Sections 2.4.1 through 2.4.13 of the LRA, the supporting information in the Plant Hatch FSARs, the applicant's responses to the staff's RAIs, and the additional information provided in telephone conferences and by letter dated January 31, 2001, the staff concludes that there is reasonable assurance that the applicant has identified those portions of the Plant Hatch structures and structural components that are within the scope of license renewal and subject to an AMR, in accordance with 10 CFR Part 54.4(a) and 10 CFR Part 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical Components

In Section 2.5, "Electric Power and Instrumentation and Controls Screening Results," of the Plant Hatch LRA, the applicant describes the electrical components that are within the scope of license renewal and subject to an AMR. The staff reviewed this section of the LRA to determine whether there is reasonable assurance that all SSCs within the scope of license renewal have been identified, as required by 10 CFR Part 54.4(a), and that all structures and components subject to an AMR have been identified, as required by 10 CFFR Part 54.21(a)(1).

2.5.1 Summary of Technical Information in the Application

The electrical component screening process has the following steps:

- Develop a comprehensive list of all electrical component types installed in the plant without regard for system function or license renewal in-scope status.

- Determine the basic function of each type of electrical component.

- Determine which component types perform their functions without moving parts or a change in configuration or properties. This results in the list of electrical component types which are subject to an aging management review for license renewal.

- Apply the scoping criteria of 10 CFR 54.4(a)(1) through (3) to the list of component types to determine if the list can be reduced.

On the basis of this scoping methodology, the applicant identified the following systems in order to determine which electrical components groups are subject to an aging management review:

- analog transmitter trip system
- nuclear steam supply shutoff system
- primary containment isolation system
- reactor protection system
- remote shutdown system
- process radiation monitoring system
- heat trace system
- main control room panels system
- in-plant auxiliary control panels system
- plant AC electrical system
- DC electrical system
- plant communications system
- power transformers system
- emergency response facilities system

The applicant's scoping methodology identified the following electrical device types and their intended functions as subject to an aging management review:

• Cable (inside containment)	Provides insulation resistance to prevent shorts, grounds, and unacceptable leakage currents
• Cable (outside containment)	Provides insulation resistance to prevent shorts, grounds, and unacceptable leakage currents
• Electrical connectors, splices, terminal blocks	Provides insulation resistance to prevent shorts, grounds, and unacceptable leakage currents

• Electrical penetration assemblies	Provide insulation resistance to prevent shorts, grounds, and unacceptable leakage currents
• Nelson frames	Fission product barrier Fire protection
• Phase bussing	Provides insulation resistance to prevent shorts, grounds, and unacceptable leakage currents

2.5.2 Staff Evaluation

The staff reviewed Section 2.5 of the LRA to determine whether there is reasonable assurance that the applicant has identified the electrical components within the scope of license renewal, in accordance with 10 CFR 54.4, and subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

2.5.2.1 Electrical Components Within the Scope of License Renewal and Subject to an Aging Management Review

In the first step of its evaluation, the staff determined that the applicant had properly identified the electrical components types installed in the plant. The applicant developed the following comprehensive list of electrical component types installed in the plant without regard for system function or license renewal in-scope status:

alarm units
analyzers
annunciators
batteries
battery chargers
cables
circuit breakers
controllers
converters
electric heaters
electrical connectors
electronic devices
emergency lighting
fuses
grounding
heat tracing
indicators
installed communication equipment
isolators
magnetic contactors
motor-generator sets
motors
penetration assemblies
penetrations (Nelson frames)
phase bussing
power distribution
power supply
recorders
regulators
relays
sensors
signal conditioners
switches
timers
transformers
transmitters
valve operators

In the second step of its evaluation, the staff reviewed the basic function of each component type and the applicant's determination of which component types perform their functions

without moving parts or a change in configuration or properties (passive and long-lived components) and therefore are subject to an AMR. The staff concludes that the applicant has properly identified the passive, long-lived component types.

In the third step of its evaluation, the staff reviewed the list of passive, long-lived component types to determine which met the criteria of 10 CFR 54.4(a)(1) through (3). This step defined the set of electrical component types subject to an AMR

The following is a list of in-scope electrical component types subject to an aging management review:

- cable (inside containment)
- cable (outside containment)
- electrical connectors, splices, terminal blocks
- electrical penetration assemblies
- Nelson frames (penetrations)
- phase bussing

Finally, the staff reviewed the information submitted by the applicant and verified that the applicant had not omitted or misclassified any electrical components requiring an AMR.

2.5.2.2 Conclusions

On the basis of the staff's review of the information presented in Section 2.5 of the LRA and the supporting information in the Plant Hatch FSAR, the staff did not find any omissions by the applicant, and therefore concludes that there is reasonable assurance that the applicant has identified those parts of the electrical systems that are within the scope of license renewal, as required by 10 CFR Part 54.4(a), and subject to an AMR, as required by 10 CFR Part 54.21 (a)(1).

3 AGING MANAGEMENT REVIEW

Section 3 of this SER provides the staff's evaluation of SNC's aging management review. The applicant provided a proposed supplement to the Final Safety Analysis Report (FSAR) in Section A 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. By letter dated July 28, 2000, the staff issued requests for additional information (RAIs) related to Section A of the LRA. In response, by letter dated October 10, 2000, the applicant provided Section B to the LRA. Section B to the LRA addressed many of the RAIs related to Section A of the LRA.

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. Therefore, the resolution of the information that needs to be added to the FSAR supplement will be addressed after the other open items are resolved, prior to the issuance of the renewed license. The content of the FSAR supplement will be tracked as Open Item 3.0-1.

3.1 Aging Management Programs

This section of the SER contains the staff's evaluation of the aging management programs (AMPs) that are in Sections A, B, and C of the LRA and referenced as a part of the aging management for the various systems and/or structures of Plant Hatch. It should be noted that the staff's conclusions on its evaluations for some of these AMPs assume that they are implemented in conjunction with other relevant AMPs, as discussed in Sections 3.2 to 4.7 of this SER, for managing aging effects for a particular system or structure.

The staff's evaluation of the applicant's AMPs focused on program elements rather than the details of specific plant procedures. To determine whether the applicant's AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the current licensing basis (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 processes, (9) administrative controls, and (10) operating experience.

The draft SRP-LR, released in 1997, describes the 10 basic elements of an effective AMP. The NRC staff evaluated the proposed programs against the 10 elements. This SER describes the extent to which the 10 elements are applicable to particular components and aging effects. Based on experience with maintenance programs, the staff concludes that conformance with the applicable elements provides the basis to conclude that the programs are demonstrably effective at managing the associated aging effects.

The applicant indicated that elements (7) corrective actions, (8) confirmation processes, and (9) 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 that are subject to an AMR. The staff's evaluation of the applicant's corrective action program is discussed in Section 3.1.8 of this SER.

3.1.1 Reactor Water Chemistry Control

3.1.1.1 Introduction

The applicant described its reactor water chemistry control AMP in Sections A.1.1, B.1.1, and C.1.2.1 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The components exposed to the reactor water environment and require aging management are contained in the following commodity groups: reactor pressure vessel, reactor pressure vessel internals, Class 1 carbon steel components, Class 1 wrought and forged stainless steel components, Class 1 cast austenitic stainless steel components, non-Class 1 carbon steel components and non-Class 1 stainless steel components.

The management of the aging effects by the reactor water chemistry control program for the components contained in the above commodity groups is described in Sections C.2.1.1.1, C.2.1.1.2, C.2.1.1.3, C.2.1.1.4, C.2.1.1.5, C.2.2.1.1 and C.2.2.1.2 of the LRA. The objective of the reactor water chemistry control AMP is to optimize the water chemistry so that the damage caused by the aging effects will be minimized. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that it will adequately manage the effects of aging caused by the reactor water environment in the plant during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.1.2 Summary of Technical Information in the Application

In the LRA, the applicant has identified the following mechanical systems which contain the components that are affected by the reactor water chemistry:

- reactor assembly system
- nuclear boiler system
- reactor recirculation system
- high pressure coolant injection system
- reactor core isolation cooling system
- main condenser system
- electro-hydraulic control system

The details of these systems are described in Section 2.3 of the LRA.

The applicant evaluated the potential aging effects requiring management for the components exposed to the reactor water environment. The aging effects applicable to these components are:

- loss of material due to general corrosion, crevice corrosion and pitting
- cracking due to stress corrosion cracking and intergranular attack (IGA)

The control of reactor water chemistry is accomplished in accordance with Electric Power Research Institute (EPRI), TR-103515, “BWR Water Chemistry Guidelines”.

3.1.1.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant’s LRA regarding the applicant’s reactor water chemistry control program to ensure that the effects of aging on components exposed to reactor water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a reactor water environment.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the LRA regarding the applicant’s demonstration of the reactor water chemistry control program to ensure that the effects of aging due to the reactor water chemistry will be adequately managed, so that the intended functions will be maintained consistent with the CLB for the period of extended operation for all components in the systems included in the scope of the program. After completing the initial review, by letter dated July 28, 2000, the staff issued several requests for additional information (RAIs). By letter dated October 10, 2000, the applicant responded to the staff’s RAIs.

The components exposed to the reactor water environment are made of carbon steel, low-alloy carbon steel, austenitic stainless steel, and nickel-based alloys. The aging effects to be managed by the reactor water chemistry control program are loss of material and cracking. Loss of material is due to pitting, crevice corrosion, and general corrosion occurring mainly in carbon steel. Cracking is due to stress corrosion cracking (SCC) and intergranular attack (IGA) in austenitic stainless steels and nickel-based alloys.

The IGA is considered a precursor for the SCC and provides the sites for crack initiation. The stress corrosion cracking consists of intergranular stress corrosion cracking (IGSCC), transgranular stress corrosion cracking (TGSCC) and irradiation assisted stress corrosion cracking (IASCC). The mechanisms of these aging effects which could be managed by the subject program are discussed in Section C.1.2 of the LRA. The aging effects are caused by the presence of excessive detrimental impurities (such as chlorides and sulfates) and oxygen content in the reactor water. The staff review did not identify any other aging effects that may be induced by the reactor water environment.

The applicant’s reactor water chemistry control program is based on the guidance provided in EPRI TR-103515, “BWR Water Chemistry Guidelines.” In the staff’s RAIs regarding program elements that deviate from the referenced EPRI guidelines, the applicant indicated that this program meets the guidelines of EPRI TR-103515, Revision 2. The staff notes that EPRI TR-103515, Revision 2, has not been approved by the staff for generic use. Therefore, the applicant should clarify the differences between Revision 1 and Revision 2 of EPRI TR-103515, so the staff can determine whether the provisions of Revision 2 are acceptable. This is Open Item 3.1.1-1.

Program Scope

The objective of the program is to mitigate the aging effects due to loss of materials and cracking. The components in the relevant commodity groups and systems that are exposed to the reactor water environment and require aging management by this program are listed in Section C.2 of the LRA. The staff finds that the scope of the subject AMP is adequate because it applies to components that are exposed to the reactor water environment.

Preventive or Mitigating Actions

The subject program controls the fluid purity and composition of the reactor water in the reactor coolant system and other systems, such as condensate/feedwater cycle, the reactor water cleanup (RWCU) system. This is achieved through the use of filters/demineralizers that limit impurities within the feedwater, and hydrogen injection that minimizes the amount of oxygen produced by radiolysis within the core. The staff finds that the mitigation methods are acceptable because they are effective in minimizing the aging effects in the affected components.

Parameters Monitored or Inspected

The subject program monitors coolant conductivity, and sulfate and chloride concentrations. When hydrogen water chemistry (HWC) is in service, electrochemical potential (ECP) is also monitored. The staff finds that the monitoring of these parameters is adequate in determining the quality of the reactor water.

Detection of Aging Effects

The applicant stated that the reactor water chemistry control is a mitigative activity and as such is not intended to directly detect age-related degradation of the affected components. The staff concurs with the applicant’s statement.

Monitoring and Trending

The subject program does not monitor or trend age-related component degradation. However, the BWR water chemistry guidelines provide guidelines for data collection and trending methodologies for evaluation of reactor water chemistry control parameters. The conductivity is monitored continuously and the chloride and sulfate concentrations are monitored daily. ECP is monitored continuously when HWC is in service. The staff finds that the monitoring and trending of the reactor water chemistry control parameters based on BWR water chemistry guidelines will identify deterioration of the reactor water chemistry.

Acceptance Criteria

The applicant stated that the acceptance criteria for the reactor water chemistry control parameters are based on the BWR water chemistry guidelines. The acceptance criteria for the reactor water chemistry control parameters vary with the plant operating modes (cold shutdown, startup/hot shutdown, or power operation) and the water chemistry condition (normal water chemistry or HWC). In Section B.1.1 of the LRA, the applicant identified the minimum reactor

water control parameters (conductivity < 0.30μS/cm, chlorides < 5 ppb and sulfates < 5 ppb) for action level 1 during normal power operation and referenced the BWR water chemistry guidelines as its basis.

Operating Experience

The major aging related component degradation in the reactor water environment is due to IGSCC in austenitic stainless steel materials. The applicant identified IGSCC in instrument penetrations, core spray sparger, and various components in the jet pump, core shrouds and recirculation system piping. These degraded components were either repaired or replaced. One of the key contributors to the IGSCC degradation is the dissolved oxygen content in the reactor water. The applicant installed HWC equipment in both units to reduce the oxygen content in the reactor water, so that the aging effect of IGSCC in the affected components can be minimized. The applicant implemented noble metal chemical addition (NMCA) to Unit 1 during the 1999 refueling outage and to Unit 2 during the 2000 refueling outage. The implementation of NMCA would further reduce the oxygen content in the reactor water. The staff concludes that the applicant's reactor water chemistry control program will adequately manage the referenced aging effects, so that the structure and component intended functions will be maintained during the period of extended operation.

The staff notes that the applicant, in its response to RAI 3.1.1-2, committed to meet the reactor water chemistry control parameters provided in the BWR water chemistry guidelines, but did not commit to a specific acceptable water chemistry mode. This is acceptable because the BWR water chemistry guidelines allow for both HWC and normal water chemistry operation. However, this would impact the applicant's in-service inspection (ISI) program. As delineated in BWRVIP-75, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules (NUREG-0313)" and BWRVIP-62, "Technical Basis for Inspection Relief for BWR Internal Components with Hydrogen Injection," the extent and frequency of the required IGSCC inspection for those affected components depends on the mode of the reactor water chemistry operating condition.

3.1.1.4 Conclusions

The staff has reviewed the information in Section A.1.1, "Reactor Water Chemistry Control," and Section B.1.1, "Reactor Water Chemistry Control," of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, pending satisfactory resolution of Open Item 3.1.1-1, the staff concludes that the applicant has demonstrated that, in conjunction with other AMPs, the effects of aging associated with structures and components exposed to a reactor water environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2 Closed Cooling Water Chemistry Control

3.1.2.1 Introduction

The applicant described its closed cooling water (CCW) chemistry control AMP in Sections A.1.2, B.1.2, and C.1.2.3 of the LRA. The staff reviewed these sections of the LRA to determine

whether the applicant has demonstrated that the effects of aging will be adequately managed so that intended function(s) of systems exposed to the CCW environment will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 Summary of Technical Information in the Application

In Sections A.1.2 and B.1.2 of the LRA, the applicant describes the CCW chemistry control program, which manages, in part, the aging effects of stainless steel, carbon steel and copper based alloy components exposed to the CCW environment. The makeup water for this system is clean, de-ionized water exclusively provided by the demineralized water system.

The applicant stated in the LRA that the components exposed to the CCW environment are found in the reactor building closed cooling water system (RBCCW) and the primary containment chilled water system (Unit 2 only).

3.1.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's CCW chemistry control program to ensure that the effects of aging on components exposed to CCW will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a CCW environment.

Program Scope

The CCW chemistry controls are applied to the reactor building closed cooling water system and the primary containment chilled water system (Unit 2 only), which include stainless steel, carbon steel, and copper-based alloy components. The CCW chemistry control program is applied to all closed cycle cooling water systems; however, only limited parts of these systems are within the scope of license renewal since these systems are not vital to safe shutdown of the plant under normal or accident conditions. The staff finds it appropriate and acceptable to include these systems in this AMP since these portions are in scope to maintain primary containment integrity.

Preventive or Mitigative Actions

The CCW chemistry control program is designed to mitigate and prevent age-related degradation (loss of material through corrosion) by controlling fluid purity and composition. Specifically, this program adds nitrite/molybdate as a ferrous alloy corrosion inhibitor and tolytriazole (TTA) as a copper alloy inhibitor to promote protective oxide layer formation on surfaces. Although the source of makeup water for this system is clean, de-ionized water, biological contamination of this closed system may occur from in-leakage and/or maintenance activities. Therefore, isothiazolone and glutaraldehyde are added to the water to control the formation of microbe populations. In the event of elevated chloride concentrations, contributed by the addition of isothiazolone, the system is fed and bled with demineralized water.

The staff finds it appropriate and acceptable to treat the cooling water system with these chemical additions to preclude the internal loss of material.

Parameters Inspected or Monitored

The application states that EPRI TR-107396, “Closed Cooling Water Chemistry Guideline” provides the basis for monitoring closed cooling water to ensure adequate chemistry control at Plant Hatch. This guideline provides several treatment options and includes control parameters such as pH and corrosion inhibitor concentrations. Diagnostic parameters include biocide, ammonia, chloride, and sulfate concentrations; microbe populations; and conductivity. The RBCCW system is equipped with carbon steel corrosion coupons which are periodically analyzed to verify the effectiveness of the corrosion inhibitor system.

The staff finds that the monitoring of these parameters is appropriate and acceptable in maintaining the effectiveness of this AMP.

Detection of Aging Effects

The application states the CCW chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of components within the scope of this program. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that the CCW chemistry control program does not directly monitor or trend age-related degradation and is not credited for such; however, the EPRI document provides the basis for trending, tracking, and evaluating CCW chemistry. The applicant notes that engineering personnel assist in performing evaluations of the structural integrity of the in-scope plant systems and, when necessary, chemistry modification is performed. These evaluations involve the identification of sources of raw-water in-leakage and evaluations to limit and prevent future chemistry excursions in the closed cooling water system. The staff agrees that there is no need to directly monitor or trend age-related degradation and finds the applicant’s implementation of guidelines from the EPRI document appropriate and conservative.

Acceptance Criteria

The application states that acceptance criteria for the following parameters are based on the EPRI document: sulfates, chlorides, pH, Na_2MoO_4, $NaNO_2$, and TTA. In addition, the applicant monitors bacteria populations monthly and weighs carbon steel corrosion coupons semiannually.

The staff finds that the applicant’s acceptance criteria based on the EPRI document validates the effectiveness of this chemistry control AMP and ensures that the corrosion rates occurring within the CCW systems are not significant. Therefore, the staff concludes that the acceptance criteria is appropriate and adequate in ensuring that the aging effects of components exposed to component cooling water are effectively managed during the period of extended operation.

Operating Experience

The application states that the CCW chemistry has evolved as a result of increased industry research, operating experience, and specific issues associated with chemical additions and testing methods. In the past, CCW treatments consisted of molybdates only because nitrite additions were contributing to bacteria population growth. However, the molybdates consumed dissolve oxygen in the system and left the carbon steel surfaces vulnerable to corrosion. Plant Hatch returned to adding nitrites to the system which effectively corrected the corrosion issues associated with using molybdates alone. Plant Hatch resolved the issue of increased bacteria population growth by adding new biocides. While these biocides were effective in controlling bacteria population growth, this addition increased chloride concentrations. In response to this increase, a bleed and makeup process using demineralized water was used to reduce the chloride concentrations. The applicant makes note that, currently, the corrosion coupon data is well within the limits recommended by industry standards.

The staff finds that, based on the applicant's operating history and the industry-wide use of this program, the CCW chemistry control program will adequately manage the aging effects of components exposed to the CCW environment.

3.1.2.4 Conclusions

The staff has reviewed the information in Section A.1.2, "Closed Cooling Water Chemistry Control," Section B.1.2, "Closed Cooling Water Chemistry Control, and Section C.1.2.3 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a CCW environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3 Diesel Fuel Oil Testing

3.1.3.1 Introduction

The applicant described its diesel fuel oil testing program in Sections A.1.3, B.1.3, C.2.2.7.1, and C.2.2.7.2 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on components in systems exposed to a fuel oil environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.3.2 Summary of Technical Information in the Application

The applicant specified that the diesel fuel testing program applies to the emergency diesel generator fuel oil storage tanks, fuel oil day tanks, and the associated transfer piping and other components. It also covers the fire pump diesel fuel oil storage tanks and the associated piping and other components in the fire protection system included in the LRA scope. Tables 3.2.4-18 and 3.2.4-19 of the LRA identify the components.

The applicant evaluated aging effects for the components subjected to an AMR and has determined that the aging effects of the components remaining within the scope of LRA and exposed to diesel fuel oil containing accumulated water and additives are caused by the following phenomena: (1) loss of material caused by general corrosion, galvanic corrosion, crevice corrosion, pitting and microbiologically influenced corrosion (MIC), (2) flow blockage, (3) cracking due to thermal fatigue.

In the LRA, the applicant identified two AMPs: one managing the corrosive effects of diesel fuel oil and the other managing thermal fatigue cracking of the piping carrying the oil. The corrosive effects of diesel fuel oil are managed by the diesel fuel oil testing program, which consists of two elements:

- regularly checking diesel fuel oil storage and day tanks in the emergency and fire pump diesel generators for the presence of water, verifying that the total particulate concentration is within acceptable limits, and removing accumulated water.

- sampling new fuel oil before off loading from the delivery vehicle, and introducing an additive which minimizes growth of microorganisms which could induce MIC.

The program for managing cracking of piping caused by thermal fatigue is addressed generically in the TLAA program in Section 4.2 of the LRA. The staff's review of this TLAA can be found in Section 4.2 of this SER. The applicant concluded that these programs will manage aging effects in such a way that the intended function of the components of the diesel fuel oil storage and transfer systems will be maintained consistent with the CLB, under all operating conditions during the period of extended operation.

3.1.3.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's diesel fuel oil testing program to ensure that the effects of aging on components exposed to fuel oil will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a fuel oil environment.

The environment in the diesel fuel oil storage and transfer system consists of the fuel oil, which may contain accumulated water and be contaminated with some impurities. Although fuel oil in its pure form is non-corrosive to metals, the presence of water, naturally occurring contaminants, or some fuel additives can create a corrosive environment. In the diesel fuel storage and transfer systems, the components included within the scope of the license renewal and exposed to this environment are constructed from carbon steel and stainless steel. These components are subject to loss of material due to general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and cracking due to thermal fatigue. However, operating experience in several plants indicated an extremely low incidence of corrosion failure of the components exposed to diesel fuel oil. The recorded incidents were related mostly to clogging of strainers with sediments and degraded oil. At Plant Hatch, the deficiencies in the diesel fuel oil supply system with age-related implications were limited to unacceptable sediment and water levels in the diesel fuel oil storage tanks, and these deficiencies were successfully resolved. No significant

aging due to thermal fatigue cracking is expected. However, since several components are potentially exposed to thermal fatigue, the applicant included this aging effect in the LRA.

Based on the above discussion, the staff finds that there is reasonable assurance that the applicant has included all the plausible aging effects related to the diesel fuel oil system for aging management consideration.

To manage the aging effects due to the presence of water, particulates, and other contaminants in the diesel fuel oil storage and transfer systems, the applicant has a diesel fuel oil testing program consisting of two elements: sampling new fuel oil, and verification that the total particulate concentration is within acceptable limits.

Program Scope

The scope of the program includes emergency diesel generator fuel oil storage and transfer systems, and fire pump diesel fuel oil storage tanks, and the associated systems containing structures and components for which age-related effects were identified. The staff finds that all the relevant systems were included in the program.

Preventive or Mitigating Actions

Regular checking for the presence of water, particulates, and other contaminants is performed in these systems and accumulated water is removed. Also, in order to prevent introduction of contaminants into the diesel fuel oil system, new oil is sampled before it is introduced into the storage tanks. During the off loading, a biocide is added to minimize corrosion due to MIC. The staff finds that these procedures are adequate because they include all the activities needed to mitigate age-related effects in structures and components included in the scope of license renewal.

Parameters Monitored or Inspected

The staff finds that inspection for water, particulates, and other contaminants in the storage tanks, and sampling new fuel oil for contaminants before its introduction into the tanks, will give sufficient protection against formation of corrosive environments which could cause damage to in-scope SSCs.

Detection of Aging Effects

The diesel fuel oil testing program, like the various chemistry control programs in effect at Plant Hatch, is a mitigative activity which is not intended to directly detect age-related degradation. The implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program. Steel storage tanks are susceptible to corrosion from the outside by contact with the earth unless an effective cathodic protection system is employed. The applicant does not take credit for such a system. Also, water in the fuel oil will be in contact with the tank bottom, possibly causing corrosion. The diesel fuel oil testing program will not be able to detect such degradation. Therefore, the staff concludes that a one-time inspection program is warranted for the diesel fuel oil tanks to verify tank bottom thickness. The addition of a one-time inspection program for the tanks would be

consistent with the applicant's approach for other chemistry control programs at Plant Hatch. For example, the torus submerged components inspection program complements the applicant's suppression pool chemistry control. Also, the condensate storage tank inspection complements the applicant's demineralized water and condensate storage tank chemistry control program. The staff requests the applicant provide specific attributes of an inspection program, consistent with other one-time inspections (e.g., inspection scope, inspection technique, acceptance criteria, etc.). This is Open Item 3.1.3-1.

Monitoring and Trending

There is no monitoring and trending aspects to the diesel fuel oil testing program, nor did the staff identify a need for such.

Acceptance Criteria

The acceptance criteria specified by the applicant requires less than 0.05% by volume of water and sediments to be present in the new fuel oil shipments, and the stored fuel oil should have no more than 10 mg/liter of particulates. In addition, a three-level composite sample from the emergency diesel generator storage tank and middle sample from the fire pump diesel oil storage tank should have water and sediment concentration not exceeding 0.05% by volume. The concentration in a bottom sample from these tanks should not exceed 0.1% of water and sediment by volume. The staff concurs with the applicant that these criteria will ensure that the aging effects in the diesel fuel oil system will be properly managed.

Operating Experience

Inspection of the industry-wide data showed an extremely low incidence of failure of components exposed to fuel oil. The inspection did not identify any incidents caused by corrosion and the only deficiency reported in several plants was clogging of strainers with sediments and degraded oil. A review of the applicant's data for the past 5 years has uncovered several deficiencies. These deficiencies were screened to determine which of them were potentially related to aging. The results of the screening have indicated that the deficiencies were limited to instances of unacceptable sediment and water levels within the diesel fuel oil storage tanks. However, they were promptly restored to acceptable limits through the corrective actions program. No instances of component failure due to age-related degradation were identified. As discussed above under the element "Detection of Aging Effects," this mitigative program should be supplemented by a one-time inspection to provide direct evidence of the absence of corrosion caused by either external or internal environments.

3.1.3.4 Conclusions

The staff has reviewed the information in Sections A.1.3 and B.1.3, "Diesel Fuel Oil Testing," C.2.2.7.1, and C.2.2.7.2 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, and upon resolution of Open Item 3.1.3-1, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a fuel oil environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4 Plant Service Water and RHR Service Water Chemistry Control

3.1.4.1 Introduction

The applicant described its plant service water and RHR service water (PSW and RHRSW) chemistry control AMP in Sections A.1.4, B.1.4, and C.1.2.4 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging of components in systems exposed to PSW and RHRSW will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.4.2 Summary of Technical Information in the Application

In Sections A.1.4 and B.1.4 of the LRA, the applicant describes the PSW and RHRSW chemistry control program, which manages, in part, the aging effects of carbon steel, cast iron, copper alloy, galvanized steel and stainless steel components exposed to the PSW and RHRSW system environment. The PSW and RHRSW are drawn from two raw water sources: river water supplied from the Altamaha River and well water supplied from deep draft wells located on site. The components exposed to a PSW and RHR service water environment are found in the PSW system and the residual heat removal system.

3.1.4.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's PSW and RHRSW chemistry control program to ensure that the effects of aging on components exposed to PSW and RHRSW will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in PSW and RHRSW environments.

Program Scope

PSW and RHR service water chemistry controls are applied to the PSW system, RHR system, and traveling water screens/trash rack system, which include carbon steel, copper alloy, gray clad iron, cast austenitic stainless steel, stainless steel clad carbon steel and stainless steel components. The staff finds it appropriate and acceptable to include these systems in this AMP.

The staff found a discrepancy regarding whether the PSW and RHRSW chemistry control program manages aging effects associated with valve bodies in the traveling water screens/trash racks system. By letter dated January 31, 2001, the applicant clarified that the isolation valve in the screen wash system credits the PSW and RHRSW chemistry control program. Specifically, the isolation valve in the screen wash line, credited by the FHA safe shutdown list, credits this chemistry program to mitigate the effects of aging.

Preventive or Mitigative Actions

The PSW and RHRSW chemistry control program is designed to mitigate and prevent age-related degradation (loss of material through corrosion) by controlling the biological growth in the

service water systems. Specifically, this program adds sodium hypochlorite alone or in conjunction with sodium bromide, and is coordinated with the periodic operation of the RHRSW to maximize chemical treatment.

The staff finds it appropriate and acceptable to treat the service water system with these chemical additions to preclude the internal loss of material through biofouling.

Parameters Inspected or Monitored

The application states that during PSW system chlorination and bromination, free available oxidant (FAO) concentration is periodically monitored at the PSW discharge to the circulating water flume to ensure program efficiency. The plant's National Pollutant Discharge Elimination System (NPDES) permit governs the levels of discharged measurable chlorine, FAO, and total residual oxidant levels.

The staff finds that monitoring of these parameters is appropriate and acceptable in determining the effectiveness of this AMP. Specifically, the FAO concentration at the discharge is a good indicator of the effectiveness of the chlorination and bromination in controlling the biofouling.

Detection of Aging Effects

The application states the PSW and RHRSW chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of components within the scope of this program. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that chemical additions under this AMP are monitored routinely through the treatment cycles which occur 5 times per week for 6 to 12 hours. During this treatment, FAO is monitored, which ensures that the system is operating consistent with the requirements and limitations of the plant NPDES permit.

The staff finds that the frequency of monitoring the established chemistry parameters is acceptable and appropriate to ensure that the aging effects of components within the scope of this program are managed.

Acceptance Criteria

The application states that the site NPDES permit provides diagnostic parameters and associated limitations for effective control of biological organisms. In addition, the permit provides for additional chemical treatment every fifteen minutes until no residual oxidant is detected. These results are reported quarterly to the State of Georgia Department of Natural Resources.

The staff finds that the applicant's criteria, based on the applicant's NPDES permit, are acceptable and appropriate for ensuring that a deviation from these parameters can be corrected to ensure that component functions of the components are maintained during the period of extended operation.

Operating Experience

The application states that the plant has experienced biofouling problems with algae and has found evidence of the Asiatic clam. These sources of biofouling have yet to impair the effectiveness of components within the scope of this AMP. The applicant currently implements the chemical treatments consistent with the recommendations of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and incorporates industry guidance, vendor recommendations, and plant-specific experience. The applicant states that periodic evaluation of this chemical treatment optimizes control of biofouling while maintaining discharge limits within the NPDES permit. The staff finds that, based on the applicant's operating history and the industry-wide use of this program, that the PSW and RHRSW chemistry control program will adequately manage the aging effects in the PSW system, RHRSW stystem, and the traveling screens/trash racks system.

During a telephone conference (telecon) with the applicant on November 8, 2000, the staff noted that Table 3.2.4-16 of the LRA identifies the PSW and RHRSW chemistry control program as managing aging associated with valve bodies in the traveling water screens/trash racks system. However, the description of the PSW and RHRSW chemistry control program in Section B.1.4 of the LRA does not include the traveling water screens/trash racks system within the scope of the program. During the telecon, the applicant committed to revising Section B.1.4 in the FSAR Supplement to include the traveling screens/trash racks system within the scope of the PSW and RHRSW chemistry control program. By letter dated January 31, 2001, the applicant clarified this formally.

3.1.4.4 Conclusions

The staff has reviewed the information in Section A.1.4, "Plant Service Water (PSW) and Residual Heat Removal (RHR) Service Water Chemistry Controls," Section B.1.4, "Plant Service Water (PSW) and Residual Heat Removal (RHR) Service Water Chemistry Controls," and Section C.1.2.4 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to a PSW and RHRSW will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5 Fuel Pool Chemistry Control

3.1.5.1 Introduction

The applicant described its fuel pool chemistry control AMP in Sections A.1.5, B.1.5, C.2.6.5, and C.2.6.6 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems

exposed to a fuel pool environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.5.2 Summary of Technical Information in the Application

The fuel pool chemistry control activities mitigate aging in the fuel pool liner and associated components through the control of fluid purity and composition. The basis for the methodology employed to maintain fuel pool chemistry parameters within acceptable limits is provided in EPRI document TR-103515, "BWR Water Chemistry Guidelines." These activities are applicable to stainless steel liners for the spent fuel pool, spent fuel pool plugs, spent fuel pool gate, refueling canal, spent fuel pool racks, and miscellaneous steel inside the spent fuel pool. In addition, aluminum seismic restraints for the spent fuel pool racks are managed through these activities.

3.1.5.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's fuel pool chemistry control program to ensure that the effects of aging on components exposed to fuel pool water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a fuel pool water environment.

Program Scope

Fuel pool chemistry control activities are applied to the fuel storage system, which includes the spent fuel pool liner, components, and racks.

Fuel pool chemistry control activities are applied to the fuel storage and refueling equipment systems, which include aluminum components.

The staff agrees that it is appropriate to include the systems listed above within the scope of fuel pool chemistry control activities.

Preventive or Mitigative Actions

Fuel pool chemistry control is designed to mitigate and prevent age-related degradation by controlling fluid purity and composition. Specifically, this program focuses on minimizing detrimental ionic species (such as sulfates, chlorides, and organic carbons) and conductivity. The staff finds that the control of these and other impurities, as provided in the EPRI document, can mitigate and prevent age-related degradation.

Parameters Inspected or Monitored

The application states that fuel pool water is sampled regularly for conductivity, pH, chlorides and sulfates, filterable solids, and total organic carbons, as provided in the EPRI document. The staff finds that monitoring these parameters is adequate and sufficient to mitigate age-related degradation of the materials in the spent fuel pool.

Detection of Aging Effects

The application states that the fuel pool chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of the fuel pool and associated internal structures. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that spent fuel pool chemistry parameters are maintained in accordance within the parameters set forth in Appendix B of the EPRI document. These parameters include sulfates, chlorides, conductivity, and total organic carbon which are monitored weekly as provided in the EPRI document. In addition, fuel pool pH and filterable solids are regularly monitored. The staff finds that the frequency of monitoring the established chemistry parameters is acceptable and appropriate to ensure that a deviation from the set parameters can be corrected in a timely manner.

Acceptance Criteria

The application states that the EPRI document provides diagnostic parameters and associated limitations for chemistry analyses. The staff finds that the criteria provided in the EPRI document are acceptable and appropriate for ensuring that a deviation from these parameters can be corrected to ensure that functions of the components are maintained during the period of extended operation.

Operating Experience

The application states that the a review of the past 5 years has revealed no age-related deficiencies on the fuel pool or associated internal structures. Rare instances of minor fuel pool chemistry excursions have occurred but these instances have been determined not to be significant. In addition, the application states that the corrective actions program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. The staff finds that, based on the applicant's operating history and the industry-wide use of this program, that the spent fuel pool chemistry control activities will adequately manage aging effects associated with the fuel pool for the period of extended operation.

3.1.5.4 Conclusions

The staff has reviewed the information in Sections A.1.5, "Fuel Pool Chemistry Control," B.1.5, "Fuel Pool Chemistry Control," C.2.6.5, and C.2.6.6 of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to a fuel pool water environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6 Demineralized Water and Condensate Storage Tank Chemistry Control

3.1.6.1 Introduction

The applicant described its demineralized water and condensate storage tank chemistry control activities in Sections A.1.6, B.1.6, and C.2.2.2 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems exposed to demineralized water and condensate storage tank environments will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.6.2 Summary of Technical Information in the Application

The demineralized water and condensate storage tank (CST) chemistry control activities are intended to mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. The principal elements of these activities are regular sampling, results analysis and, when applicable, chemistry modification.

3.1.6.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demineralized water and CST chemistry control program to ensure that the effects of aging on components exposed to demineralized and CST water will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in demineralized water and CST water environments
.

Program Scope

The demineralized water and CST chemistry control is directly or indirectly monitored in the following systems:

B21-Nuclear Boiler
C11-CRD
E41-HPCI
E51-RCIC
P11-Condensate Transfer and Storage
R43-EDG
T23-Primary Containment

It is noted that while the demineralized water system proper is not within the scope of license renewal, several systems and components that receive makeup water from the demineralized water storage tank (DWST) are within the scope of license renewal. Therefore, the DWST chemistry control is an important aspect of aging management for the systems indicated above.

The staff finds the applicant's scope to be appropriate and acceptable, since these systems are monitored by the demineralized water chemistry control.

Preventive or Mitigative Actions

The staff finds that the control of detrimental ionic species and other impurities in demineralized water, as provided in the BWR water chemistry guidelines can mitigate and prevent age-related degradation. By controlling the water chemistry in the CST and DWST, the applicant reduces the potential for significant corrosion of plant systems and components exposed to a demineralized water environment. Therefore, the staff finds this approach acceptable.

Parameters Inspected or Monitored

The BWR water chemistry guidelines provide the basis for the monitored demineralized water chemistry parameters to ensure adequate chemistry control at Plant Hatch. The staff finds that monitoring these parameters is adequate and sufficient to mitigate age-related degradation of the systems and components exposed to a demineralized water environment.

Detection of Aging Effects

The application states that the demineralized water and CST chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation of the systems and components exposed to a demineralized water environment. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the specific material and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The application states that demineralized water chemistry control does not directly monitor or trend age-related degradation and as such is not credited to perform this attribute. However, the BWR water chemistry guidelines provide the basis for the methodology employed for periodic monitoring of demineralized water chemistry parameters at Plant Hatch. These parameters include sulfates, chlorides, total organic carbon, and silica, which are monitored weekly as recommended by the EPRI document. In addition, conductivity and pH are diagnostically monitored. The staff finds that the monitoring frequency identified in the BWR water chemistry guidelines is acceptable and appropriate to ensure that a deviation from the set parameters can be corrected within a timely manner.

Acceptance Criteria

The application states that the BWR water chemistry guidelines provide diagnostic parameters and associated limitations for chemistry analyses. In addition to the EPRI requirements, the applicant also diagnostically monitors pH and conductivity. The staff finds that the criteria provided in the EPRI document is acceptable and appropriate for ensuring that a deviation from these parameters can be corrected to ensure that intended functions of the components are maintained during the period of extended operation.

Operating Experience

The application states that a review of the past 5 years has revealed that no age-related deficiencies were found due to significant corrosion of system components. Rare instances of CST and DWST chemistry excursions have occurred but these instances have been determined not to be significant. In addition, the EPRI TR-103515 guidelines for auxiliary systems incorporated the input of industry experts and utility experience. Therefore, the operation, according to the guidelines specified by these EPRI guidelines, ensures that pertinent industry issues were considered. Therefore, the staff finds that, based on the applicant’s operating history and the industry-wide use of this program, that the demineralized water and CST chemistry control activities will adequately manage aging effects associated with the CST and DWST for the period of extended operation.

3.1.6.4 Conclusions

The staff has reviewed the information in Section A.1.6, ”Demineralized Water and Condensate Storage Tank Chemistry Control,” and Section B.1.6, ”Demineralized Water and Condensate Storage Tank Chemistry Control,” of the LRA. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components in systems exposed to demineralized water and CST environments will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.7 Suppression Pool Chemistry Control

3.1.7.1 Introduction

The applicant described its suppression pool chemistry control AMP in Section A.1.7 of the LRA. The applicant supplemented the description of this AMP in Section B.1.7 of the applicant’s October 10, 2000 submittal. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems exposed to a suppression pool environment will be adequately managed so that intended function(s) will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.7.2 Summary of Technical Information in the Application

In Sections A.1.7 and B.1.7 of the LRA, the applicant describes an existing AMP, the suppression pool chemistry control program, that manages, in part, aging effects for various structures and components exposed to the suppression pool environment. The affected systems include nuclear boiler, residual heat removal, core spray, high pressure coolant injection, reactor core isolation cooling, primary containment, and primary containment purge and inerting. The applicant lists the specific system structures and components that are exposed to the suppression pool environment in Section 3.2 and Section 3.3 of the LRA. These structures and components are fabricated from either carbon steel or stainless steel.

As discussed in Section C.1.2.2 of the LRA, loss of material is an applicable aging effect that may affect both carbon steel and stainless steel structures and components through several corrosion mechanisms. These mechanisms include general corrosion, galvanic corrosion, crevice corrosion, pitting, microbiologically influenced corrosion (MIC), and erosion corrosion. The applicant also considers cracking to be an applicable aging effect that may affect specific stainless steel components due to stress corrosion cracking or intergranular attack. To mitigate these corrosion-related aging effects, the applicant relies on the suppression pool chemistry control program.

The suppression pool water (also called “torus water” in the LRA) contained within the torus consists of demineralized water supplied from demineralized water sources (such as the condensate storage tank). The applicant relies on chemistry controls to mitigate aging due to corrosion in structures and components exposed to the suppression pool water by controlling the water purity and composition. The program consists of periodic sampling and testing of the suppression pool water for conductivity, chlorides, sulfates, and total organic compounds. The applicant stated that the program is based on the applicable portions of the EPRI BWR Water Chemistry Guidelines.

3.1.7.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant’s LRA regarding the applicant’s suppression pool chemistry control program to ensure that the effects of aging on components exposed to a suppression pool environment will be adequately managed, so that the functions will be maintained consistent with the CLB for the period of extended operation for all components in a suppression pool environment.

Program Scope

The applicant stated that the scope of this program included structures and components within the nuclear boiler (including safety relief valve tailpipes and associated supports), residual heat removal, core spray, high pressure coolant injection, reactor core isolation cooling, and primary containment purge and inerting systems, and primary containment (including the torus). The staff finds the program scope to be acceptable because the scope is comprehensive in that it includes all components exposed to the suppression pool water environment.

Preventive or Mitigative Actions

The program minimizes detrimental ionic species and conductivity in the suppression pool environment. The staff finds these actions acceptable because by minimizing ionic species and conductivity, one mitigates degradation due to corrosion.

Parameters Inspected or Monitored

The program monitors conductivity, chlorides, sulfates, and total organic carbons in accordance with the BWR water chemistry guidelines (EPRI TR-103515). The staff finds this acceptable because published literature and operating experience to date support the monitoring and control of these specific parameters to mitigate corrosion-related degradation.

Detection of Aging Effects

The applicant stated that the suppression pool chemistry control program is a mitigative activity which is not intended to directly detect age-related degradation. The staff agrees that the implementation of this program does not provide information directly related to the degradation of the structures and components within the scope of this program and that there is no need to do so because this program, in conjunction with other AMPs, provides a means of mitigating or preventing age-related degradation.

Monitoring and Trending

The applicant stated that the frequency of the suppression pool water sampling is on a quarterly basis, consistent with the EPRI guidelines. The staff finds this frequency to be acceptable because operating experience to date supports this frequency to be often enough to detect and correct anomalous chemistry conditions before there is a loss of intended functions. The applicant also stated that they monitor and trend the sampling results. Monitoring and trending provide important information about how a program is performing relative to acceptance criteria. Proactive monitoring and understanding of trending behavior allow for corrective actions to be taken prior to exceeding the acceptance criteria. Monitoring and trending of water chemistry parameters are also consistent with the EPRI BWR water chemistry guidelines. The staff therefore finds this approach to be acceptable.

Acceptance Criteria

The applicant applies the acceptance criteria consistent with those in the BWR water chemistry guidelines. The staff finds this acceptable because the acceptance criteria have low thresholds to allow for the early detection and correction of anomalous chemistry conditions.

Operating Experience

Operating experience provides the staff additional information about the acceptability of an AMP. The applicant reviewed plant deficiency cards over the past 5 years that showed that no age-related deficiency report had been written on the structures or components within the scope of license renewal for which suppression pool chemical control is credited. Suppression pool chemistry excursions have been rare. In the past five years, only minor excursions above the EPRI criteria have occurred. The applicant stated that none of these excursions was determined to be significant.

Additionally, the program follows the EPRI BWR water chemistry guidelines that incorporate the input of industry experts and utility experience and thus ensures the consideration of pertinent industry issues. These guidelines have been used by the industry for many years. Based on acceptable operating experience to date, the staff believes this guidance has proven itself effective in minimizing corrosion-related degradation in the suppression pool water environment.

3.1.7.4 Conclusions

The staff has reviewed the information in Section A.1.7, "Suppression Pool Chemistry Control" and Section B.1.7, "Suppression Pool Chemistry Control" of the LRA, and the applicant's

responses to the staff's RAIs. On the basis of its review, the staff concludes that, in conjunction with other AMPs, the applicant has demonstrated that the effects of aging associated with structures and components exposed to a suppression pool environment will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.8 Corrective Actions Program

3.1.8.1 Introduction

In Sections A.1.8, "Corrective Action Program" and B.1.8, "Corrective Action Program" of the LRA, the applicant describes the aging management program credited for initiating corrective actions when age-related degradation is identified in structures and components subject to an AMR. The staff reviewed this AMP to determine if the applicant has included the attributes needed for an adequate AMP.

The license renewal applicant is required to demonstrate that the effects of aging on structures and components subject to an AMR will be adequately managed to assure that their intended functions will be maintained consistent with the CLB of the facility for the period of extended operation. Therefore, those aspects of the AMR process that affect the quality of safety-related structures, systems, and components, are subject to the quality assurance (QA) requirements of Appendix B to 10 CFR Part 50. For nonsafety-related structures and components subject to an AMR, the existing 10 CFR Part 50, Appendix B QA program may be used by the applicant to address the elements of corrective actions, confirmation process, and administrative controls.

3.1.8.2 Summary of Technical Information in the Application

Section A.1.8 and Section B.1.8 of the LRA provide a brief description of the corrective actions program (CAP) and states that the CAP applies to all systems, structures, and components within the scope of license renewal. The CAP is also described as part of the applicant's Quality Assurance Program required by 10 CFR Part 50 Appendix B.

LRA Section A.1.8.1 states that the CAP is briefly described in chapter 17 of the Plant Hatch Unit 2 Final Safety Analysis Report (FSAR) and asserts that this process will be effective for correcting potential age-related degradation that may be discovered during the renewal term. The primary vehicle for initiating corrective action at the plant is the condition reporting process. Existing procedures include the necessary forms and instructions for reporting potential problems related to aging management of the systems, structures and components (SSCs) within the scope of license renewal. Significant conditions adverse to quality require initiation of a special report. Significant occurrences are investigated to determine root cause, and actions are taken to preclude recurrence. Forms and guidance for root cause analysis are provided in Plant Hatch procedures and guidelines. Corrective actions are part of the QA program, as required for the Plant Hatch current license term under Criterion XVI of Appendix B to 10 CFR Part 50.

3.1.8.3 Staff Evaluation

During the scoping and screening audit conducted from June 12 through June 15, 2000, the applicant's implementation of the corrective actions process described in LRA Section 3.1.8 was reviewed by the staff.

Section C.2 of the LRA provides an AMR summary for each unique structure, component, or commodity group determined to require aging management during the period of extended operation. This summary includes identification of aging effects requiring management, aging management programs utilized to manage these aging effects, and attribute tables that demonstrate how the identified aging management programs manage aging effects. The staff found that the attributes identified for each AMR were consistent with those attributes described in Table A.1-1 of the draft SRP-LR. However, the Plant Hatch LRA does not describe each of these attributes and, therefore, the applicant was requested to provide this information in RAI 3.1.8-1, issued on July 28, 2000.

In its October 10, 2000, response to the staff's RAI, SNC confirmed that the description for each of the 10 attributes is the same as the description given in the draft SRP-LR. Section B to the October 10, 2000 submittal included a description of these attributes. The staff has reviewed the corrective actions, administrative controls, and confirmation process aging management program attributes described by the applicant in Section B to the RAI response and concluded that they are consistent with the description given in the draft SRP-LR and are, therefore, acceptable. Accordingly, RAI 3.1.8-1 is closed.

Section A.2 of the draft SRP-LR, requires a license renewal applicant to demonstrate that the effects of aging on structures and components subject to an aging management review will be adequately managed to ensure that their intended functions will be maintained consistent with the current licensing basis of the facility for the period of extended operation. Consistent with this approach, the applicant's aging management programs should contain the elements of corrective action, confirmation process, and administrative controls in order to ensure proper management of the aging programs.

Section C.2 of the LRA provides an aging management summary for each unique structure, component, or commodity group at Plant Hatch determined to require aging management during the period of extended operation. For the majority of these AMRs, corrective actions, confirmation process, and administrative controls are specifically addressed by reference to the applicant's CAP. However, Section A.1.8 of the LRA, does not describe how the CAP program specifically addresses those three attributes for which credit is being sought. Therefore, in RAI 3.1.8-2, the applicant was requested to provide a description of how the CAP program specifically addresses these three attributes for the aging management programs at Plant Hatch during the period of extended operation.

In its October 10, 2000, response to the staff's RAI, SNC stated that the LRA used the label "Corrective Action Program" for a combination of plant activities that includes the plant's corrective action program and portions of the plant's 10 CFR 50 Appendix B quality assurance (QA) program. SNC added that Appendix B to the RAI response provided a description of how this program addresses the attributes credited.

In Section B to its October 10, 2000, RAI response, SNC provided a summary of aging management programs for license renewal. Under Section B.1 of the Section, the applicant stated the following:

> “The Corrective Action Program is credited for the following four attributes for all aging management activities at Plant Hatch:
>
> - Attribute 7 - Corrective actions, including root cause determination and prevention of recurrence, are included.
> - Attribute 8 - Confirmation process is included.
> - Attribute 9 - Administrative controls should provide a formal review and approval process.
> - Attribute 10 - Operating experience of the aging management program, including past corrective actions resulting in program enhancements or additional programs, are considered.”

Further, in Section B.1.8 of the October 10, 2000 submittal, the applicant described in detail how corrective actions, confirmation process, and administrative control elements are to be met for all aging management programs at Plant Hatch. As described in Section B.1.8, SNC has established and implemented a QA Program for Plant Hatch that conforms to the criteria set forth in 10 CFR Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants”. The QA program addresses all aspects of quality assurance at Plant Hatch.

The two elements of the Plant Hatch QA program that are most pertinent to the aging management programs credited for license renewal are corrective actions and administrative controls. These elements are discussed in Chapter 17 of the Plant Hatch Unit 2 FSAR, and are outlined below. Corrective action and administrative control requirements apply to all components within the scope of license renewal.

Program Scope

The plant condition reporting process applies to all plant systems and components within the scope of license renewal. Administrative controls are in place for existing aging management programs and activities and for the currently required portions of enhanced programs and activities. Administrative controls will also be applied to new programs and activities as they are implemented. As a minimum, these programs and activities are or will be performed in accordance with written procedures. Those procedures are or will be reviewed and approved in accordance with Plant Hatch’s 10 CFR 50, Appendix B, QA Program.

The staff finds that the applicant has adequately identified that all structures, components, and commodity groups within the scope of the CAP.

Preventive or Mitigative Actions

The CAP provides a means to correct conditions identified as being adverse to quality. There are no preventive or mitigative attributes specifically credited for this program. The staff finds that the CAP is not a preventive or mitigative activity and instead, corrects conditions found to be adverse to quality.

Parameters Inspected or Monitored

No specific parameters are inspected or monitored as part of this program. Generally, when parameters inspected or monitored by other plant programs indicate a condition adverse to quality, the Corrective Action Program provides a means to correct the identified condition. The staff agrees that this program does not inspect or monitor parameters, nor should it.

Detection of Aging Effects

Detecting aging effects is not part of the CAP. The CAP provides a means to address the aging effects identified by other AMPs. The staff agrees that the purpose of this program is not to detect aging effects, but to provide corrective actions when other AMPs identify aging effects.

Monitoring and Trending

The corrective action process is monitored and trended to ensure that corrective actions taken are adequate and timely. Significant and non-significant conditions are trended. Plant Hatch monitors significant conditions that are adverse to quality (significant occurrence reports) and requires a formal cause determination and corrective actions to prevent recurrence. The staff finds that the CAP adequately monitors and trends significant conditions to identify and correct the adverse conditions in a timely manner.

Acceptance Criteria

The CAP does not include specific acceptance criteria for in-scope components. Generally, when the acceptance criteria of other AMPs are not met, the CAP provides a means to ensure appropriate corrective actions are taken. The staff agrees that the purpose of the CAP is to correct and restore components that do not meet acceptance criteria.

Corrective Actions

Corrective action is initiated following the determination of conditions adverse to quality, and documented as required by appropriate procedures. Various processes are used to identify problems requiring corrective action. The primary vehicle for initiating corrective action at Plant Hatch is the condition reporting process described in Section 17.2.15 of the Unit 2 FSAR.

The various components of corrective action provide for timely corrective actions, including root cause determination and prevention of recurrence. The QA program provides control over activities affecting the quality of systems, structures, and components consistent with their

importance to safety. In accordance with plant procedures, condition reports are analyzed for adverse trends. Any identified adverse trends are reported to the appropriate department for corrective action.

The staff finds the corrective action process acceptable, appropriate, and sufficient to identify and correct conditions adverse to quality in a timely manner.

Confirmation Process

As described in Unit 2 FSAR Section 17.2.15, condition reports are reviewed to determine the regulatory reportability and significance. Those items found to be significant conditions adverse to quality are also reviewed. Corrective actions taken for significant items are reviewed for assurance that appropriate action has been taken.

The staff finds that the confirmation process is adequate to assure that corrective actions are appropriate and complete.

Administrative Controls

Activities affecting quality are prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and are accomplished in accordance with these instructions, procedures, or drawings. They contain appropriate acceptance criteria and documentation requirements for determining whether important activities have been satisfactorily accomplished. Site procedures establish review and approval requirements.

The staff finds the administrative controls to be adequate to assure that corrective actions are uniform and thorough.

Operating Experience

The CAP provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

Review of the operating experience sections for the other AMPs provides numerous examples of the CAP being used to address and correct age-related conditions adverse to quality.

The results of CAP audits since 1995 were reviewed. The review determined that findings from the CAP audits have resulted in enhancements to the CAP.

On the basis of its review of operating experience discussed in the LRA, the staff finds that the CAP has been effective in correcting conditions adverse to quality. Further, the staff finds that the applicant's evaluation process for the CAP has resulted in improvements to the program.

On the basis of the information provided in the LRA, as supplemented by the information in Section B to SNC's October 10, 2000, RAI response, with respect to the applicability of Appendix B to 10 CFR Part 50 requirements to the corrective actions, confirmation process, and administrative control attributes for the aging management programs at Plant Hatch, the staff

has determined that there is reasonable assurance that the applicant’s QA program will adequately address those attributes during the period of extended operation. Therefore, RAI 3.1.8-2 is closed.

In addition, on the basis of the information provided in the LRA, as supplemented by the information in Section B to SNC’s October 10, 2000, submittal, with respect to the remaining program attributes, the staff has determined that there is reasonable assurance that the applicant’s QA program will adequately address those attributes during the period of extended operation.

3.1.8.4 Conclusion

The staff has reviewed the information presented in Section A.1.8, “Corrective Actions Program” and Section B.1.8, “Corrective Actions Program.” On the basis of this review, the staff concludes that the Plant Hatch FSAR Supplement containing the corrective actions, confirmation process, and administrative control attributes described in Section B to SNC’s October 10, 2000 RAI response, and which are governed by the Plant Hatch QA program, will provide reasonable assurance that these aging management program attributes will be implemented in an acceptable manner during the period of extended operation. In addition, the staff concludes that the remaining program attributes provide reasonable assurance that the corrective actions program will manage the aging effects associated with components within the scope of license renewal and subject to an AMR.

3.1.9 Inservice Inspection Program

3.1.9.1 Introduction

The applicant described its inservice inspection (ISI) program AMP in Sections A.1.9 and B.1.9 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that this program will manage the effects of aging on structures and components such that the associated systems will perform their intended function(s), consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

The ISI Program is a condition monitoring program that provides for the implementation of ASME Code, Section XI, in accordance with the provisions of 10 CFR 50.55a. The ISI Program also includes augmented examinations required to satisfy commitments made by the applicant (e.g., GL 88-01, NUREG-0619). The 10-year examination plan provides a systematic guide for performing nondestructive examination of passive components within the scope of license renewal.

Plant Hatch has two units with different dates for construction permits and operating licenses. However, Unit 2's first 10-year interval was completed early (1986), so both units would be committed to the same version of ASME Section XI. Accordingly, Plant Hatch is currently in the third ten-year interval. The period of extended operation will include the fifth and sixth ISI intervals.

3.1.9.2 Summary of Technical Information in the Application

The ISI program provides examination methods and acceptance criteria for Class 1, 2, 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for periodic pressure testing of those same components, along with repair, replacement, and modification activities.

Three types of inspection methods are used for inservice examination at Plant Hatch. They are visual inspections, surface inspections, and volumetric inspections. Visual inspections are performed as defined in ASME Code, Section XI, Subsection IWA-2210. Three types of visual examinations are used: VT-1, VT-2, and VT-3. VT-1 inspections are used to determine the condition of the part, component, or surface examined, including cracks, wear, corrosion, and/or physical damage. VT-2 inspections are used to locate evidence of leakage from pressure retaining components during a system pressure test. VT-3 inspections are used to determine the general mechanical and structural condition of components and in associated supports, such as verification of clearances, physical displacements, and loose or missing parts. This includes inspection for debris, corrosion, wear, erosion, and/or loss of integrity at bolted or welded connections.

Surface examinations are performed as defined in Subsection IWA-2220 to determine whether surface cracks or discontinuities exist. Acceptable examination methods include magnetic particle and liquid penetrant methods. Volumetric examinations are performed as defined in IWA-2230 to locate discontinuities throughout the volume of material. These examinations may be conducted from the inside or outside surface of a component. Either radiographic (RT) or ultrasonic examination (UT) methods may be used.

ASME Section XI, Subsections IWB, IWC, IWD and IWE provide examination requirements for ASME Class 1, 2, and 3 (equivalent) and Class MC components, respectively. Subsection IWF addresses component supports, which are treated the same as the Code Class component they support. Code Case N-491 is an acceptable alternative to the tables and scope expansion requirements of ASME Section XI, Subsection IWF.

3.1.9.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the ISI program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that the ISI program contains examination requirements and acceptance criteria for Class 1, 2, and 3 (equivalent), and Class MC pressure boundary components, as well as the associated supports. It also provides for repair, replacement, and modification activities.

The ISI Program is credited for monitoring potential age-related degradation in portions of the following systems:

B11 - Reactor Assembly
B21 - Nuclear Boiler
B31 - Reactor Recirculation
E11 - Residual Heat Removal (RHR) and RHR Service Water
P41 - Plant Service Water
T23 - Primary Containment
T52 - Containment Penetrations

The staff finds the program scope to be acceptable because the scope is comprehensive in that it includes all components for which the ISI program applies.

Preventive or Mitigative Actions

The applicant stated that the ISI program is a condition monitoring program. Therefore, there are no preventive or mitigative attributes associated with this program. The staff agrees that the ISI program does not prevent or mitigate age-related degradation, but rather identifies age-related degradation.

Parameters Inspected or Monitored

The applicant stated that the ISI program utilizes visual, surface, and volumetric examinations of Class 1, 2, and 3, and Class MC pressure boundary components, as well as the associated supports, that would detect potential degradation of their intended functions, due to loss of material and cracking, during the period of extended operation. The applicant stated in Section B.1.9 of the LRA, that the ISI program will also be used to detect loss of preload for the in-scope systems and components.

The staff finds the parameters to be inspected or monitored to be acceptable.

Detection of Aging Effects

The applicant stated that the ISI Program monitors the aging effects using visual, surface, and volumetric inspection methods. To ensure that the aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. The applicant stated that the extent and frequency of examinations for components subject to ASME Section XI requirements at Plant Hatch are based on the tables in Article 2500 of ASME Section XI, Subsections IWB, IWC, IWD, IWE, and IWF. The staff finds that the ASME Code requirements used to detect aging effects are adequate.

Monitoring and Trending

The applicant stated that deficiencies discovered during the performance of the program activities are documented in accordance with the procedures implementing the Plant Hatch ISI program. Deficiencies discovered through the ISI program are monitored in accordance with

ASME Code requirements. Deficiencies requiring repair or replacement are entered into the plant corrective action program. The staff finds this process adequate to effectively monitor and trend age-related degradation.

Acceptance Criteria

The applicant stated that, for the third ten-year inspection interval, Plant Hatch uses the 1989 Edition of the ASME Code, Section XI, for Class 1, 2, and 3 systems and components. Components not meeting the acceptance criteria defined in ASME Section XI, Tables IWB-2500-1, IWC-2500-1, and IWD-2500-1 are evaluated, repaired, or replaced prior to returning to service. In 1996, Plant Hatch submitted a request for relief from meeting the requirements of the ASME Code for Class MC component repairs and replacement until September 9, 1997. The NRC approved the request for relief in May 1997. Accordingly, repairs, replacements, or modifications for Class MC components that occurred after September 9, 1997, have been performed in accordance with the requirements of the ASME Code, Section XI, 1992 Edition with 1992 Addenda. The staff finds that the acceptance criteria used by the applicant is acceptable.

Operating Experience

The applicant stated that the Plant Hatch ISI program is based upon the requirements of the ASME Code. The ASME Code development process includes extensive review and approval by industry experts, thereby assuring that any significant industry data has been considered in the development of the ASME Code, which forms the basis for the Plant Hatch ISI program. In addition, the Commission's process of reviewing Editions and Addenda of the ASME Code and incorporating them into 10 CFR 50.55a provides additional assurance that all significant issues have been considered. The applicant stated that several deficiencies have been identified on the in-scope components and systems. For those identified as age-related, the applicant's corrective actions program was used to address the concerns, in accordance with Plant Hatch's implementation of ASME Code, Section XI, within the ISI program. The corrective actions program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. The staff finds that the acceptance criteria used by the applicant for this AMP is appropriate.

3.1.9.4 Conclusions

The staff has reviewed the information in Sections A.1.9 and B.1.9, "Inservice Inspection Program," of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the ISI program will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.10 Overhead Crane and Refueling Platform Inspections

3.1.10.1 Introduction

The applicant described its overhead crane and refueling platform inspections in Sections A.1.10 and B.1.10 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging managed by the overhead crane and refueling platform inspections will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.10.2 Summary of Technical Information in the Application

In Section A.1.10 of the LRA and Section B.1.10 of the applicant's October 10, 2000 submittal, the applicant describes an existing aging management program, the overhead crane and refueling platform inspection program, that provides for periodic visual inspections to monitor the condition of the passive structural elements of the crane and refueling platform with respect to their structural integrity. The applicant identified loss of material due to corrosion as the aging effect requiring management by this program. The affected mechanical systems include the refueling platform equipment assembly and the reactor building crane. The applicant lists the specific systems, structures, and components in Section 3.2 of the LRA. These two mechanical systems are fabricated from either carbon steel or aluminum. In addition to the overhead crane and refueling platform inspection program, the protective coatings program, which is described in Section A.2.3 of the LRA, is also used to manage the loss of material aging effect for these two mechanical systems.

The applicant states that the overhead crane and refueling platform inspection activities satisfy the requirements of the Unit 1 Technical Requirements Manual, which has provisions for surveillance testing of the 5-ton hoist and the crane /hoist used for handling fuel assemblies or control rods. The overhead crane and refueling platform hoist, rigging, slings and lifting devices are visually inspected to detect evidence of loss of material. The overhead crane and refueling platform inspection program also includes a number of other inspection activities that are not credited for license renewal aging management, such as a pre-operational static inspection, pre-operational dynamic inspection, operational inspection, and maintenance inspection.

3.1.10.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the overhead crane and refueling platform inspections program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In Section B.1.10 of the applicant's October 10, 2000 submittal, the applicant states that the reactor building overhead crane and refueling platform are generally considered to be active

components; however, the components that are responsible for the structural integrity of the crane and refueling platform are considered to be passive, and are thus within the scope of license renewal. The passive structural load-bearing components include the crane girder, rails, and bolts. Regarding the inspection scope, SNC stated, in response to RAI 3.1.10-2, that the active moving sub-components of the overhead crane and refueling platform, such as the wire rope, drums, and other associated parts, are not within the scope of license renewal. Therefore, aging effects such as cracking of the wire rope and mechanical degradation/distortion due to fatigue were not considered for the overhead crane and refueling platform inspection program. In response to RAI 3.1.10-5, SNC stated that galvanic corrosion between the aluminum rivets and structural steel of the refueling equipment assembly is not an aging effect requiring management because the aluminum surfaces exposed to air will develop a thin oxide coating, and no electrolyte is present to initiate or sustain a galvanic reaction. The staff finds that the scope of the overhead crane and refueling platform inspections program is acceptable since it includes a visual inspection of all of the passive components that are responsible for the structural integrity of the overhead crane and refueling platform.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The contacting surfaces of the passive structural load bearing components of the overhead crane and refueling platform such as the crane girder, rails, and bolts, are periodically inspected in accordance with plant procedures. The staff finds that visual inspections will be adequate for identifying loss of material from these surfaces during the period of extended operation.

Detection of Aging effects

With respect to the frequency interval of inspections, the applicant stated in Section B.1.10 of its October 10, 2000, submittal that general visual inspections are performed monthly and that the overhead cranes are inspected daily when in use. The staff finds that the applicant’s operating experience to date supports the continuation of this inspection frequency interval and will provide reasonable assurance that the loss of material aging effect will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that the results of the system inspections and tests are documented in accordance with procedural requirements. In addition the corrective actions program is used to monitor the component deficiencies and to implement timely corrective actions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

Acceptance Criteria

The applicant states that the acceptance criteria for the overhead crane and refueling platform inspection program is that, “bridges, bridge rails, trolley, and trolley rails must be straight, and without evidence of physical damage such as cracking.” The staff finds that the acceptance criteria specified above are adequate to ensure that the system intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

The overhead crane and refueling platform inspection program is an existing program; however, the applicant did not provide a description of the program inspection findings. In response to RAI 3.1.10-6, the applicant stated that a review of the “plant deficiency cards” from the past 5 years did not reveal any loss of material from the in-scope components of the overhead crane or the refueling platform. The staff finds that the applicant’s operating experience has demonstrated that the overhead crane and refueling platform inspection program has effectively maintained the structural integrity of the overhead crane and refueling platform, and the effects of aging will be adequately managed so that the system intended function will be maintained during the period of extended operation.

3.1.10.4 Conclusions

The staff has reviewed the information in Sections A.1.10 and B.1.10, “Overhead Crane And Refueling Platform Inspections” of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the overhead crane and refueling platform inspection program will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.11 Torque Activities

3.1.11.1 Introduction

The applicant described its torque activities AMP in Sections A.1.11, B.1.11, C.2.1.1.6, and C.2.2.10 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging managed by the torque activities will be adequately managed so that the systems covered by this activity will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.11.2 Summary of Technical Information in the Application.

Torque activities are intended to mitigate loss of preload through use of proper torque techniques at Plant Hatch. Plant procedures provide specific instructions for maximizing the effectiveness of torque activities.

Hardened steel washers may be used in conjunction with joint bolting, since they allow more of the applied torque to be translated to bolt stress, which provides the preload necessary for a tightly sealed joint. In joints subject to thermal or process load cycling, Belleville washers or extra-length bolting may be used to provide better response to the changing conditions caused by cycling.

Bolting threads and load bearing faces are lubricated with an approved thread lubricant immediately before assembly to allow the maximum torque to be translated to bolt stress. Leveling passes are performed using a calibrated torquing tool and continue until there is no rotational movement of the fasteners at the final torque value.

For any joint considered at high risk for leakage, as demonstrated by past performance or based on the judgment of the responsible supervision, leveling passes may be repeated at the final torque value after 24 hours. This may be done to compensate for gasket relaxation (creep) prior to putting the joint into service.

3.1.11.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the torque activities AMP to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The application stated that the plant commodity group in the scope for this activity is class 1 pressure boundary bolting and non-class 1 pressure boundary bolting. Class 1 pressure boundary bolting is fabricated from low alloy steel. The non-class 1 pressure boundary bolting is fabricated to the requirements of ASTM A-307 (Grade B), ASME SA-194 (Grade 2H), and ASME SA-193 (Grade B7). Bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. In response to RAI 3.4-1, the applicant did not state if the yield strength for ASME SA-193 (Grade B7) or any other bolts are limited to less than 150 ksi to avoid the possibility of stress corrosion cracking. See RICSIL No. 055, February 1, 1991, "RPV Head Stud Cracking." The staff requests the applicant to provide this information. This is Open Item 3.1.11-1.

The systems where torque activities are applied that contain class 1 pressure boundary bolting are:

B21 - Nuclear Boiler
B31 - Reactor Recirculation

The systems where torque activities are applied that contain Non-Class 1 pressure boundary bolting are:

B21 – Nuclear Boiler
C11 – Control Rod Drive

E11 – Residual Heat Removal
E21 – Core Spray
E41 – High Pressure Coolant Injection
E51 – Reactor Core Isolation Cooling
N61 – Main Condenser
P41 – Plant Service Water
P42 – Reactor Building Closed Cooling Water
P52 – Instrument Air
P64 – Primary Containment Chill Water
P70 – Drywell Pneumatic
T23 – Primary Containment
T41 – Reactor Building HVAC
T48 – Primary Containment Purge and Inerting
T49 – Post LOCA Hydrogen Removal
W33 – Traveling Water Screens, Trash Racks
X41 – Outside Structures HVAC
X43 – Fire Protection
Y52 – Fuel Oil
Z41 – Control Room HVAC

The staff agrees that it is appropriate to include the systems listed above within the scope of torque activities.

Preventive or Mitigative Actions

The applicant states for both Class 1 and non-Class 1 bolting, the torque activities are designed to mitigate age-related degradation by controlling preload within bolted connections. The staff agrees that torque activities are preventive actions and are appropriate for the systems listed.

Parameters Inspected or Monitored

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that this attribute is not needed.

Detection of Aging Effects

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that this attribute is not needed.

Monitoring and Trending

The applicant states that the torque activities sufficiently mitigate loss of preload such that this attribute of aging management is not required. The staff agrees that monitoring and trending is not required for torque activities.

Acceptance Criteria

The torque activities provide acceptance criteria for loss of preload by specifying torque values, bolt sequence, number of passes, and thread engagement. The staff agrees that the activities specified provide an adequate acceptance criteria.

Operating Experience

The application states that the corrective actions program provides for evaluation of aging effects and significant operating events, and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences. The staff finds this acceptable.

3.1.11.4 Conclusions

The staff has reviewed the information in Sections A.1.11, "Torque Activities," B.1.11, "Torque Activities," C.2.1.1.6, and C.2.2.10 of the LRA. On the basis of this review, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has demonstrated that the aging effects managed by the torque activities will be adequately managed so that there is reasonable assurance that the systems covered by this activity will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.12 Component Cyclic and Transient Limit Program

3.1.12.1 Introduction

The applicant described its component cyclic and transient limit program (CCTLP) in Sections A.1.12 and B.1.12 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging managed by the CCTLP will be adequately managed so that the systems covered by this program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.12.2 Summary of Technical Information in the Application

In Section A.1.12 of the LRA and Section B.1.12 of the applicant's October 10, 2000 submittal, the applicant describes an existing aging management program, the component cyclic and transient limit program, that "is designed to track cyclic and transient occurrences to ensure that reactor coolant pressure boundary components and the torus will remain within ASME Code Section III fatigue limits, including the effects of a reactor water environment." The monitored locations include four limiting high stress RPV boundary components on each unit, limiting locations for the torus on each unit, and eight locations within the Class 1 boundary. These monitoring locations are discussed in greater detail in Section 4.2 of this SER. The program requires that the cumulative usage factor (CUF) for each limiting component for each unit be updated at least once per operating cycle. The program also requires that corrective actions be initiated if the CUF is projected to exceed the Code limit during the next operating cycle. In addition, the applicant identified this AMP as the method it uses to manage the fatigue TLAAs for the period of extended operation in accordance with 54.21(c)(1)(iii).

3.1.12.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the component cyclic and transient limit program to ensure that the reactor coolant pressure boundary components and the torus will remain within ASME Code III fatigue limits for the period of extended operation.

Program Scope

The scope of the program includes the RPV, the torus and all Class 1 piping. The program monitors locations of high fatigue usage determined by the applicant's review of the design calculations. The staff has identified Open Item 4.1.3-1 in Section 4.1 of this safety evaluation regarding the scope of the applicant's fatigue TLAA evaluation. Specifically, the staff requests that the applicant explain how the fatigue analysis of the vessel internals was found to be acceptable for the 60-year period. The staff also requests that the applicant identify any other components of the reactor coolant pressure boundary that had fatigue analyses and explain how these analyses were found acceptable for the 60-year period. Pending satisfactory resolution of Open Item 4.1.3-1, the staff finds that the scope of the CCTLP is adequate.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The monitored locations are discussed in Section 4.2 of this SER. The staff finds that monitoring these selected high fatigue usage locations provides an acceptable method to monitor the fatigue usage due to design transients for the RPV, torus, and Class 1 piping.

Detection of Aging Effects

The program monitors design transients used in the fatigue analysis of components and the information is used to update the fatigue calculation. The staff identified Open Item 4.2.3-1 in Section 4.2.3 of this SER regarding the applicant's evaluation of environmental fatigue concerns. Specifically, the staff disagrees with the applicant's determination that environmental fatigue concerns regarding the six locations identified in NUREG/CR-6260 have been adequately addressed at Plant Hatch. Pending satisfactory resolution of Open Item 4.2.3-1, the staff finds that the aging effects will be adequately monitored by this program.

Monitoring and Trending

According to the applicant, the projected 60-year CUF is updated at least once per operating cycle. The applicant indicates that if the fatigue usage factor is projected to exceed 1.0, a condition report is initiated to determine, and take, appropriate corrective action. The applicant lists the following potential corrective actions:

- trend the 60-year CUF projection and verify that CUF will not exceed 1.0 during the current operating cycle

- refine the fatigue analysis and modify the monitoring formula

- use fracture mechanics analysis to determine a critical flaw size and establish an appropriate inspection schedule

- perform corrective maintenance

- replace the component

The staff considers refinement of the fatigue analysis, repair, or replacement of the component acceptable corrective actions. The use of a fracture mechanics analysis for cases where the CUF is projected to exceed 1.0 would require staff review and approval on a case-by-case basis.

Acceptance Criteria

As stated above, the applicant's acceptance criteria is the condition that the CUF for the monitored locations not exceed 1.0. The staff considers this criteria acceptable, pending resolution of Open Item 4.2.3-1 regarding the applicant's evaluation of environmental fatigue effects.

Operating Experience

The applicant's program involves tracking transients at locations of high calculated fatigue usage to manage the fatigue TLAAs. The applicant indicated that it has modified its counting procedure based on operating experience and has added additional monitoring points to the program. Thus, the staff concludes that the applicant considered operating experience in the program development.

3.1.12.4 Conclusions

The staff has reviewed the information in Sections A.1.12, "Component Cyclic and Transient Limit Program," and B.1.12, "Component Cyclic and Transient Limit Program," of the LRA. The applicant references the component cyclic and transient limit program in its discussion of the fatigue TLAAs as a method to manage the fatigue usage of selected components. The staff has identified open items regarding the applicant's TLAA evaluation in Sections 4.1 and 4.2 of this SER. Pending satisfactory resolution of Open Items 4.1.3-1 and 4.2.3-1, the staff considers the applicant's program, which monitors the number of plant transients that were assumed in the fatigue design of selected high-fatigue-usage components, to be an acceptable method to manage the fatigue usage of the RPV, torus structure and RCS piping.

Pending satisfactory resolution of the open items regarding the applicant's fatigue TLAAs, the staff concludes that the component cyclic and transient limit program will adequately manage thermal fatigue of RCS components and torus structure components for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.13 Plant Service Water and RHR Service Water Inspection Program

3.1.13.1 Introduction

The applicant described the PSW and RHRSW inspection program in Section A.1.13 of the LRA. The applicant supplemented the description of this AMP in Section B.1.13 of its October 10, 2000 submittal. The applicant credits this inspection program with managing, in part, aging effects for a variety of carbon steel, stainless steel, copper alloy, and gray cast iron components that are exposed to a raw water or buried environment. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the PSW and RHRSW inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.13.2 Summary of Technical Information in the Application

In Sections A.3.7 and B.3.7 of the LRA, the applicant describes the PSW and RHRSW inspection program, that manages, in part, aging effects for various structures and components exposed to a raw water or buried environment. The affected systems include the RHR system, PSW system, and traveling water screens/trash racks system. The applicant lists the specific system structures and components in Tables 3.2.3-2, 3.2.4-7, and 3.2.4-16 of the LRA. These structures and components are fabricated from either carbon steel, stainless steel, copper alloy, or gray cast iron.

As discussed in Sections C.1.2.4 and C.1.2.10 of the LRA, loss of material is an applicable aging effect that may affect carbon steel, stainless steel, copper alloy, or gray cast iron components exposed to raw water or buried environments through several corrosion mechanisms, including general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, selective leaching, and erosion corrosion. The applicant also considered fouling to be an applicable aging effect. Fouling is not a material degradation phenomenon but may increase corrosion rates within raw water system components for a limited set of component geometries. Additionally, fouling may result in a loss of intended function (i.e., decreased flow or pressure) due to the buildup of material on raw water system component internal surfaces. Although the applicant also identified wear and cracking due to vibration fatigue as applicable aging mechanisms, these mechanisms are specific to the RHR heat exchanger which has its own AMP (the RHR heat exchanger augmented inspection and testing program), and thus are not addressed by the PSW and RHRSW inspection program.

Plant Hatch has two sources of raw water, river and well water. River water from the Altamaha River is supplied and rough screened at the intake structure. The applicant assumes that some debris, silt, and macroorganisms may be introduced into the PSW and RHRSW systems. This is the type of raw water relevant to this inspection program. The applicant relies on a combination of AMPs to mitigate and detect aging effects for the various structures and components exposed to the river water environment. These complementary programs include the PSW and RHRSW chemistry control program, the PSW and RHRSW inspection program, the structural monitoring program, galvanic susceptibility inspections, and the RHR heat exchanger augmented inspection and testing program. This section of the SER describes and evaluates the applicant's plant service water and RHR service water inspection program.

3.1.13.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the PSW and RHRSW inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated in Section B.1.13 of the LRA, that the scope of this program included structures and components within the RHR system, PSW system, and traveling water screens/trash rack system, as specified in Tables 3.2.3-2, 3.2.4-7, and 3.2.4-16 of the LRA. The inspection scope consists of a representative sample of the most susceptible locations for corrosion or fouling. Locations susceptible to corrosion include infrequently used piping (stagnant water), submerged piping, piping with low fluid velocity, piping with high fluid velocity (erosion), small diameter piping, backing rings, socket welds, and heat affected zone of welds. Locations susceptible to fouling include those also susceptible to corrosion, horizontal runs of piping at the bottom of vertical runs, intermittently used piping, or low point drains. To address selective leaching, the applicant will include one PSW component fabricated from brass and one component fabricated from gray cast iron.

In Section C.2.4.3 of the LRA, the applicant credits the PSW and RHRSW inspection program with managing the aging effects of RHR and PSW components exposed to a buried environment. The inspection program includes provisions for cleaning, priming, coating, and wrapping underground pipelines whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping. However, this aspect of the program is not discussed in Sections A.1.13 or B.1.13 of the LRA. The staff requests the applicant enhance its description of the PSW and RHRSW inspection program to clearly state that the scope of the program includes this particular aspect for managing aging effects associated with a buried environment, consistent with the discussion in Section C.2.4.3 of the LRA. This is part of Open Item 3.1.13-1.

In Table 3.2.3-2 of the LRA, the RHR heat exchanger augmented inspection and testing program is credited with managing, in part, aging effects for various heat exchanger components, including the tubes, tubesheet, and shell. However, the description of the PSW and RHRSW inspection program contained in Section B.1.13 of the LRA includes several references to inspections of heat exchanger components. The staff requests that the applicant clarify the scope of the PSW and RHRSW inspection program relative to managing aging effects for the various heat exchanger components listed in Table 3.2.3-2 of the LRA. This is part of Open Item 3.1.13-1.

The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with Division I PSW piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended

function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and AMPs are consistent with other piping sections in this system. However, the length of the PSW piping surrounded by the guard pipe is sealed, that is, the plate is welded to the PSW pipe and to the guard pipe at both ends. Thus, the external surface of this section of PSW piping is not accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The staff requests the applicant to provide appropriate information about this one-time inspection, or a comparable engineering evaluation, prior to the end of the current term. This is part of Open Item 3.1.13-1.

Pending satisfactory resolution of Open Item 3.1.13-1, the staff finds the scope of the PSW and RHRSW inspection program to be acceptable because it includes all the components in the RHR system, PSW system, and traveling water screens/trash rack system that are exposed to a raw water environment. In addition, the inspection scope includes a representative inspection sample set that is conservatively biased to those locations considered to be most susceptible to corrosion or fouling.

Preventive or Mitigative Actions

Two aspects of the PSW and RHRSW inspection program are mitigative in nature. First, the program requires the regular, periodic visual inspections of the intake structure pump suction pit. Any accumulations of biological fouling organisms, sediment, or corrosion products found during the inspection will be removed to prevent their entry into the system. The staff agrees this action will help to mitigative the impact such accumulations have on corrosion and fouling. Second, the program includes provisions for cleaning, priming, coating, and wrapping underground pipelines whenever underground sections of pipe are uncovered. Pipelines are wrapped with coal tar enamel wrapping. The staff finds this acceptable because an intact protective coating will enhance the corrosion resistance of buried piping.

Parameters Monitored or Inspected

The applicant applies qualified inspection techniques, including visual and volumetric (radiographic or ultrasonic) inspections of structures and components to detect corrosion-related aging effects. The applicant also performs flow testing and visual or volumetric inspections to detect fouling. Lastly, the applicant will perform hardness testing or a metallurgical analysis on brass or gray cast iron components to detect selective leaching. The staff finds the inspections and flow rate and hardness testing/metallurgical analysis to be acceptable because the methods are consistent with current industry practice and found to be effective in detecting these aging effects.

Detection of Aging Effects

To ensure that aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. The program scope and parameter monitoring are discussed above. With respect to frequency, the applicant stated that the visual inspection of the intake structure pump

suction pit is performed every twelve months. The hardness testing of the brass or gray cast iron components will be a one-time inspection, unless results indicate a need for future or expanded inspections. The cleaning, priming, coating, and wrapping of underground pipelines is on an as-needed basis, whenever underground sections of pipe are uncovered. Inspection frequencies for all other structures and components within the scope of this program are based on past inspection results, to ensure that minimum wall thickness values or flow areas are not reduced to unacceptable levels. The staff finds this approach of basing inspection frequency on inspection results to be reasonable and therefore acceptable.

Monitoring and Trending

As discussed above, the applicant stated that inspection results are trended to determine the scope and frequency of subsequent inspections. This approach is reasonable and consistent with industry practice and staff expectations and therefore, is acceptable to the staff.

Acceptance Criteria

For wall loss evaluations, minimum wall thickness is calculated in accordance with the piping design code, piping stress requirements, and piping specification drawings. Flow rate testing for the evaluation of pipe blockage is based upon functional performance requirements for a particular component under normal and accident conditions. Hardness testing is based on the component's material specifications (e.g., ASME, ASTM, etc.). These criteria are reasonable and consistent with industry practice and staff expectations and therefore, are acceptable to the staff.

Operating Experience

The applicant stated that review of Plant Hatch operating experience over the past 4 to 5 years has indicated some aging-related problems in the PSW and RHRSW systems. The problems consisted of loss of material and loss of heat exchanger performance. The applicant addresses these deficiencies through its corrective actions program. The applicant stated that significant improvements have been made to the plant service water and RHR service water inspection program. For example, the frequency of inspections has been increased and additional non-destructive examinations introduced. In some cases replacement components were made of improved materials. The staff concludes that the applicant has appropriately incorporated operating experience into the PSW and RHRSW inspection program. In addition, the applicant provided operating experience in its January 31, 2001 letter relative to selective leaching of gray cast iron and brass components and in Section B.2.3 of the LRA relative to corrosion of buried piping. The staff finds that this operating experience supports the attributes of this program specific to selective leaching and buried piping.

3.1.13.4 Conclusions

The staff has reviewed the information in Sections A.1.13 and B.1.13 of the LRA. On the basis of this review, pending satisfactory resolution of Open Item 3.1.13-1, the staff concludes that the applicant has demonstrated that the PSW and RHRSW inspection program will adequately manage, in conjunction with other AMPs, aging effects associated with the raw water or buried environment for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.14 Primary Containment Leakage Rate Testing Program

3.1.14.1 Introduction

The applicant described its primary containment leakage rate testing program in Section A.1.14 of the LRA. The applicant supplemented the description of this AMP in Section B.1.14 of its October 10, 2000 submittal. The applicant credits this inspection program with ensuring the structural integrity of primary containment through visual inspection and performance testing activities. Loss of material and cracking are the aging effects monitored by this program. The staff reviewed the application to determine whether the applicant has demonstrated that the primary containment leakage rate testing program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.14.2 Summary of Technical Information in the Application

In Section A.1.14 of the LRA and Section B.1.14 of the applicant's October 10, 2000 submittal, the applicant describes an existing aging management program, the primary containment leakage rate testing program, that ensures the structural integrity of primary containment. The program applies to steel primary containments, containment penetrations, and containment internal structures that perform a structural or pressure retaining function. It also includes the steel and nonferrous components of the containment airlocks, equipment hatches, and control rod drive removal hatches. The applicant lists the specific system, structures, and components in Section 3.3 of the LRA.

3.1.14.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the primary containment leakage rate testing program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In Section A.1.14 of the LRA, the applicant states that the primary containment leakage rate testing program complies with all 10 CFR 50 Appendix J, Option B leakage rate testing requirements for systems, structures, and components within the scope of license renewal. The applicant also states that the primary containment leakage rate testing program involves Type A, B, and C pressure testing and that a general visual inspection of the accessible interior and exterior surfaces of the drywell and torus are performed prior to conducting a Type A test. Based on staff review of the above information, staff RAI 3.6-1 asked the applicant to provide a discussion of the key elements of the primary containment leakage rate testing program and specifically describe the implementation of regulatory positions C1 through C4 of Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program.” The RAI also asked the applicant to provide the bases for any exceptions to these regulatory positions.

In response to RAI 3.6-1, the applicant stated that the program provides for the implementation of all 10 CFR 50 Appendix J, Option B leakage rate testing requirements, as required by the

Unit 1 and Unit 2 Technical Specifications. The applicant further stated that the program was developed through the use of 10 CFR 50, Appendix J, Option B, Regulatory Guide 1.163, NEI 94-01, and ANSI/ANS 56.8-1994. The applicant stated that no exceptions are taken to regulatory positions C.1 through C.4 of RG 1.163. This applicant's response is acceptable and RAI 3.6-1 is closed.

The staff finds that the scope of the program, as described above, is acceptable since it includes Type A, B, and C pressure testing and performance of a general visual inspection of the accessible interior and exterior surfaces of the drywell and torus, which are shown to be a reliable means of assuring containment functions based on past Plant Hatch operating experience.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

Among the parameters monitored during the testing and visual inspection are containment pressure, compartment/penetration pressures, overall containment leak rate, localized penetration/compartment closure leak rates, extent of loss of material or cracking of inspected surfaces, and localized general degradation of components or coatings.

With respect to the third paragraph of Section A.1.14.1, "Description" on page A.1-17 of the LRA, the applicant stated that "Type A tests are performed in accordance with ANSI/ANS 56.8-1994 and/or Bechtel Topical Report BN-TOP-1 and implemented through plant procedures. In RAI 3.6-2, the staff requested the applicant to explain the extent to which Plant Hatch intends to adopt the provisions of the referenced ANSI/ANS standard/report in its implementation of the Type A test program. The applicant was also requested to clarify if the provisions that were adopted from the Bechtel Topical Report BN-TOP-1 are either equivalent to or more stringent than those corresponding provisions of ANSI/ANS 56.8-1994. If not, the applicant was requested to list those BN-TOP-1 provisions that are less stringent than those of ANSI/ANS 56.9-1994 and reconcile the differences.

The applicant responded that presently Type A integrated leak rate tests (ILRTs) are performed in accordance with Bechtel Topical Report BN-TOP-1. The next ILRT is scheduled to be performed during the Unit 1 spring 2002 outage. Plans are to conduct the ILRT in accordance with BN-TOP-1. The Plant Hatch Unit 1 FSAR, Section 5.2.5.1, states that "the containment leak test program is performed in the manner described in BN-TOP-1 or ANSI/ANS-56.8-1994." The applicant also stated that Regulatory Guide 1.163 endorses NEI 94-01, which states in Section 1.1, "Generally, an FSAR describes plant testing requirements, including containment testing. In some cases, FSAR testing requirements differ from those of Appendix J. The alternate performance-based testing requirements contained in Option B of Appendix J will not invalidate such exemptions." The applicant also stated that no formal comparison of ANSI/ANS 56.8-1994 with BN-TOP-1 has been performed at this time. The staff finds this applicant's response adequate and reasonable and considers RAI 3.6-2 closed.

Detection of Aging Effects

Test and inspection frequencies are determined in accordance with plant procedures. An as-found Type B or C test is performed prior to any maintenance, repair, modification, or adjustment activities that could affect the primary containment boundary's leak-tightness. Since the primary containment leakage rate testing program cannot detect loss of material or cracking before the pressure boundary is compromised, this testing program is used in conjunction with other programs, such as the protective coatings program and the inservice inspection program, to manage the aging effects of the primary containment components and drywell penetrations. The staff finds that the applicant's operating experience to date supports the continuation of these test and inspection frequencies and they will provide reasonable assurance that loss of material, as well as loss of containment leak tightness will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant indicated that the results of tests and inspections are documented in accordance with procedural requirements. In addition, the corrective actions program is used to monitor the deficiencies found and to implement timely corrective actions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

Acceptance Criteria

The applicant stated that criteria are defined for establishing Type A, Type B, and Type C test frequencies and administrative leakage limits, based on performance. Type A tests are performed in accordance with ANSI/ANS 56.8-1994 and/or Bechtel Topical Report BN-TOP-1 to demonstrate the integrity of the primary containment pressure vessel. Type A, B, and C test intervals are established in accordance with Regulatory Guide 1.163. Type B and C tests are performed in accordance with ANSI/ANS 56.8-1994, to demonstrate the integrity of individual penetrations and components, with NRC approved Technical Specification amendments and exemptions. The acceptance criteria for visual inspection are no visual detection of loss of material or cracking. The staff finds that the acceptance criteria specified above are adequate to ensure that the containment intended functions are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

The primary containment leak rate testing program is an existing program. The applicant stated in Section C.2.6.2 of the LRA that several instances of age related degradation of the containment due to minor corrosion were found to date but there were no containment functional failures. These deficiencies were discovered during required visual inspections and pressure testing. The corrective actions program was utilized to correct/repair these deficiencies. The staff finds that the applicant's operating experience has demonstrated that the program has effectively maintained the containment integrity and functionality, and the effects of containment aging will be adequately managed so that intended functions will be maintained during the period of extended operation.

3.1.14.4 Conclusions

The staff has reviewed the information in Sections A.1.14 and B.1.14, “Primary Containment Leakage Rate Testing Program” of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the primary containment leakage rate testing program will be adequately managed so that there is reasonable assurance that the structures covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.15 Boiling Water Reactor Vessel and Internals (BWRVIP) Program

3.1.15.1 Introduction

The applicant described its Boiling Water Reactor Vessel and Internals (BWRVIP) inspection program in Section A.1.15 of Section A of the LRA. The applicant supplemented the description of this AMP in Section B.1.15 of its October 10, 2000, submittal. The applicant credits this program with verifying the structural integrity of the reactor pressure vessel (RPV) and the referenced RPV internal components to assure the continued integrity of the load bearing and operating components. The staff reviewed the application to determine whether the applicant has demonstrated that the BWRVIP inspection program will adequately manage aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.15.2 Summary of Technical Information in the Application

In Section A.1.15 of the LRA and Section B.1.15 of the applicant’s October 10, 2000, submittal, the applicant describes an existing generic aging management program, the Boiling Water Reactor Vessel and Internals (BWRVIP) inspection program, which is composed of twelve inspection and evaluation (I&E) reports for internals components, nine of which were referenced by the applicant and which address both the current term and license renewal. With regard to license renewal, the I&E reports specifically address the internals relative to the requirements of 10 CFR Part 54. The staff’s SERs on the BWRVIP I&E reports established the adequacy of the generic BWRVIP reports for renewal by concluding the license renewal rule provisions have been satisfied, including the identification and assessment of aging effects, the evaluation of the adequacy of those programs with regard to those aging effects, and demonstration that these programs will assure the functionality of internals into the renewal term.

The applicant has evaluated the BWRVIP program for its applicability to the Plant Hatch Units 1 and 2 design, construction, and operating experience, stating that the RPV internals, including the materials of construction, are addressed by the BWRVIP program I&E reports and that the plant operation parameters, including temperature, pressure and water chemistry, are consistent with those used for the development of the I&E reports. The applicant has determined that the components which require aging management review, in accordance with the license renewal rule, are covered by the referenced BWRVIP program reports, and that the referenced BWRVIP program reports cover all Plant Hatch internals design.

The BWRVIP program provides for periodic inspections to monitor the condition of each internal BWR component that could impact safety, enabling degradation to be detected before the

component's function is adversely affected. The applicant stated that the RPV internals requiring aging management within the scope of license renewal are the shroud, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. Initially, for Unit 1 only, the top guide was included, but in response to RAI 3.1.15-2, the applicant stated that, based on the original design conditions, Unit 2 was shown to not require inspection, and thus, was not referenced in the LRA; however, the applicant is re-evaluating the top guide hold-down device lift for Unit 2. The preliminary analysis shows that the Unit 2 top guide also may lift under faulted conditions. If the preliminary results are confirmed, the applicant will use the BWRVIP top guide I&E report for both units.

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable BWRVIP inspection and evaluation document, unless specific exception has been identified to, and approved by, the NRC staff. Therefore, the applicant has established that the BWRVIP program reports bound the Plant Hatch Units 1 and 2 design and operation.

3.1.15.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the BWRVIP to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In Section B.1.15 of the applicant's October 10, 2000, submittal, the applicant stated that the reactor vessel internals requiring aging management within the scope of the Plant Hatch implementation of the BWRVIP are the shroud and associated shroud repair hardware, shroud supports, core spray piping and spargers, control rod guide tubes, jet pump assemblies, control rod drive housings, and dry tubes. In the original application, only the Unit 1 top guide was included. Subsequent to submitting the application, SNC had determined that, due to extended power uprate, the Unit 2 top guide must also be included. All of the above listed components are included as part of the reactor assembly system.

The staff finds the applicant has adequately identified all components which are within the program scope.

Preventive or Mitigative Actions

The BWRVIP program is a condition monitoring program which utilizes enhanced visual inspections, as well as volumetric and surface examinations, to detect IGSCC, IASCC, and fatigue within reactor vessel internals such that proper evaluations and corrective actions may be accomplished. Early detection and subsequent evaluation and corrective actions are considered adequate to mitigate degradation of reactor assembly internals before component function is adversely affected.

The staff finds that the BWRVIP program, as used at Plant Hatch, will be adequate to monitor plant conditions to identify conditions adverse to quality in a timely manner.

Parameters Inspected or Monitored

The BWRVIP program reviewed the function of each internal BWR component. For those internals that could impact safety, the BWRVIP program considered the mechanisms that might cause degradation of the internal components and developed an inspection program that would enable degradation to be detected and evaluated before the component function was adversely affected. Details regarding inspection and evaluation are contained within the component-specific BWRVIP inspection and evaluation documents. The staff finds that the applicant has appropriately characterized how the BWRVIP will inspect and monitor components at Plant Hatch to identify and evaluate aging effects.

Detection of Aging Effects

The reactor internals are examined using a combination of ultrasonic, visual, and surface methods. The methods to be used and the frequency of examination will be as specified in the applicable I&E report.

The staff finds the detection methods, as specified, are appropriate to identify and evaluate age-related degradation in internals.

Monitoring and Trending

Monitoring of the detrimental effects of aging within reactor assembly components are specified within the BWRVIP I&E reports. The frequency of examination specified within applicable BWRVIP I&E reports varies for each component or subassembly. The frequency is based on the component's design, flaw tolerance, susceptibility to degradation, and the method of examination used. In cases where a component may be inspected using either visual or ultrasonic methods, the interval between examinations is shorter when visual methods are used. The Plant Hatch corrective actions program provides for trending of significant indications noted during BWRVIP inspections.

The staff finds the applicant's approach to monitoring and trending aging in components within the scope of the BWRVIP reports appropriate.

Acceptance Criteria

BWRVIP I&E reports provide the basis for Plant Hatch reactor vessel internals inspection requirements, acceptance criteria, and proper corrective actions. SNC has incorporated these applicable I&E reports into the Plant Hatch license renewal application by specific reference. BWRVIP I&E reports applicable to Plant Hatch reactor assembly components are as follows:

Reactor Assembly BWRVIP Document Applicability

Component	Reference
Shroud (including repair hardware)	BWRVIP-76
Shroud support	BWRVIP-38
Core spray piping and sparger	BWRVIP-18
Top guide	BWRVIP-26
Jet pump assemblies	BWRVIP-41
Control rod guide tube	BWRVIP-47

The staff finds that the acceptance criteria, as provided in the referenced BWRVIP reports, are acceptable.

Operating Experience

The applicant states that the operating experience for the Plant Hatch internals was reviewed. Over time there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installation of a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the non-safety-related steam dryers. Some have been repaired while others are monitored. Jet pump inspections have resulted in minor indications associated with setscrew gaps, diffuser-to-adapter welds, riser pipe welds, and tack welds. These are being monitored and reexamined in accordance with the provisions of the BWRVIP. Crack-like indications were also detected in the core shrouds for both units. SNC conservatively decided to make pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repair hardware and vertical welds are periodically examined as specified in the BWRVIP.

The staff finds that the applicant has adequately considered plant-specific and industry operating experience in both the development and the implementation of the BWRVIP reports.

3.1.15.4 Conclusions

The staff has reviewed the information in Sections A.1.15 and B.1.15, “Boiling Water Reactor Vessel and Internals Program,” of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the BWRVIP program will be adequately managed so that there is reasonable assurance that the systems covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.16 Wetted Cable Activities

3.1.16.1 Introduction

The applicant described its wetted cable activities in Sections A.1.16 and B.1.16 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems managed by the wetted cables activities will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.16.2 Summary of Technical Information in the Application

In Sections A.1.16 and B.1.16 of the LRA, the applicant describes an existing AMP, wetted cables activities, that provides for mitigating activities as well as condition monitoring activities associated with cables exposed to a wetted environment. Plant Hatch wetted cable activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings. Change in insulation resistance is the aging effect mitigated and monitored by the wetted cables activities.

The affected systems include RHR, RHRSW, core spray, and PSW.

3.1.16.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the wetted cables activities program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Water level is measured, recorded, and the pull boxes drained, where these in-scope 4-kV power and transformer cables are routed. Megger and polarization index testing are periodically performed. When new terminations are made, the cables are hipot tested to provide additional assurance that the cable insulation integrity is sound. In addition, the pull boxes are drained quarterly and testing is performed on in-scope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

The wetted cables activities meet the intent of IEEE 43-1974, "Recommended Practice for Testing Insulation Resistance of Rotating Machinery"; and IEEE 95-1977, "Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage." Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and polarization index testing. Corrective actions are taken if testing results are unacceptable. Plant specific operating experience did not identify any in-scope age-related cables failures due to moisture intrusion.

The staff finds that the Plant Hatch wetted cables activities manage the effects of cable aging due to moisture intrusion so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.1.16.4 Conclusions

The staff has reviewed the information in Sections A.1.16, ”Wetted Cable Activities,” and B.1.16, “Wetted Cable Activities,” of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by wetted cable activities will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.17 Reactor Pressure Vessel (RPV) Monitoring Program

3.1.17.1 Introduction

The applicant described its RPV monitoring program in Sections A.1.17 and B.1.17 of the LRA. The program consists of a combination of fatigue monitoring, code-required and augmented inspections, and surveillance material testing. The staff has reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the RPV monitoring program during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.17.2 Summary of Technical Information in the Application

The RPV Monitoring Program is an existing condition monitoring and surveillance program at Plant Hatch. It is based on detailed evaluation of the Plant Hatch Unit 1 and Unit 2 RPVs. The program is supported by an industry topical report for the license renewal period, BWRVIP-74.

The RPV Monitoring Program covers the reactor vessel beltline shells, feedwater nozzles, core spray nozzles, control rod drive return line nozzle, recirculation inlet and outlet nozzles, jet pump instrumentation nozzles, and penetration seals. The core dP and standby liquid control nozzle, the support skirt and the closure studs, the core spray pipe, jet pump riser brace pad, and shroud support welds are also included.

RPV monitoring is accomplished through a combination of fatigue monitoring, code-required and augmented inspections, pressure tests, and surveillance material testing. RPV shell and head aging management is accomplished by performing ultrasonic examinations of the RPV vertical shell welds, periodic pressure tests with visual examination for leakage, and surveillance capsule testing. Plant Hatch uses an NRC-approved technical alternative in lieu of ultrasonic testing of circumferential shell welds. This basis for the alternative is contained in the BWR reactor pressure vessel shell weld inspection recommendations, and associated supplements.

The LRA indicates that the BWRVIP is developing an Integrated Surveillance Program (ISP) for all domestic operating BWRs as allowed by 10 CFR 50 Appendix H. The ISP will be provided to the NRC by BWRVIP for review and approval. Both the Plant Hatch RPVs are included in the program.

3.1.17.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the RPV monitoring program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Section B.1.17 of the LRA describes the RPV monitoring program for Plant Hatch. The RPV monitoring program employs the programs documented in the following topical reports: BWRVIP-27, "BWR Standby Liquid Control/Core Shroud ΔP Inspection and Flaw Evaluation Guidelines," BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines," BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines," BWRVIP-48, "Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines," and BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines."

Fatigue Monitoring

The staff evaluation of fatigue monitoring is discussed in Sections 3.1.12, "Component Cyclic or Transient Limit Program" and 4.2, "Pipe Stress" of this SER.

Code-Required and Augmented Inspection and Pressure Tests

The staff evaluation of the Inservice Inspection Program is discussed in Section 3.1.9, "Inservice Inspection Program," of this SER.

Surveillance Material Testing

To evaluate whether the reactor vessel surveillance program will provide sufficient data for monitoring the amount of embrittlement during the license renewal term the staff evaluates whether the surveillance program satisfies the following attributes:

> Capsules must be removed periodically to determine the rate of embrittlement and at least one capsule with a neutron fluence not less than once or greater than twice the peak beltline neutron fluence must be removed before the expiration of the license renewal period. Capsules must contain material to monitor the impact of irradiation on the limiting beltline materials and must contain dosimetry to monitor neutron fluence. If capsules are not being removed from Plant Hatch during the license renewal period, the applicant must provide operating restrictions (i.e., inlet temperature, neutron spectrum and flux) to ensure that the RPV is operating within the environment of the surveillance capsules, and must provide ex-vessel dosimetry for monitoring neutron fluence.

In response to RAI 3.1.17-1, the applicant indicated that it plans to implement the provisions of an integrated surveillance program (ISP) that is documented in BWRVIP-78, "BWR Vessel and Internals Project: BWR Integrated Surveillance Program Plan." Should the ISP not be approved by the NRC, or if it should be modified such that Plant Hatch is not covered by the ISP, the applicant stated that it would develop an RPV surveillance program for the renewal period.

In a telephone conference on November 3, 2000, the applicant reiterated that its expectation is that the ISP, or its implementation document, will address these attributes and that, if the staff rejects BWRVIP-78, or if BWRVIP-78 is modified to the extent that the applicant cannot apply it to Plant Hatch, the applicant will develop an RPV materials surveillance program for the renewal period. As part of this commitment, if the applicant participates in the ISP or implements a plant-specific reactor vessel surveillance program, the ISP or plant-specific program should address the 10 program attributes. If the program cannot meet any program attributes, the applicant should provide a technical justification for the discrepancies. This is Open Item 3.1.17-1.

The BWRVIP has stated that a supplement to the BWRVIP-78 report, addressing how the report meets 10 CFR 54, and addressing the 10 program attributes, will be provided for staff review in the near future.

Section B.1.17 of the LRA provides a discussion of the elements of the RPV monitoring program. The elements discussed are program scope, preventive or mitigation actions, parameters inspected or monitored, method of detecting aging effects, monitoring and trending, and acceptance criteria. The scope of the program includes all components in the reactor assembly system. The description of the other elements of the program consists of a general discussion of the inspections, monitoring, surveillance, and analyses that are documented in the BWRVIP topical reports. These topical reports have been reviewed by the staff and form the basis for the staff's review of the RPV monitoring program. On the basis of the acceptability of the BWRVIP reports referenced above, pending satisfactory resolution of Open Item 3.1.17-1, the staff concludes that the RPV monitoring program is adequate to manage the aging effects associated with the components in the reactor assembly system.

3.1.17.4 Conclusion

On the basis of the staff's review of information provided in Sections A.1.17 and B.1.17 of the LRA, and the applicant's response to the staff's RAI, the staff concludes that, pending satisfactory resolution of Open Item 3.1.17-1, the applicant has demonstrated that the aging effects on the reactor pressure vessel will be adequately managed by the reactor pressure vessel monitoring program, as required by 10 CFR 54.21(a)(3).

3.1.18 Fire Protection Activities

3.1.18.1 Introduction

The applicant described its fire protection activities program in the following sections of the application: Section A.2.1, "Fire Protection Activities;" B.2.1, "Fire Protection Activities;" C.2.3, "Aging Management Reviews for Fire Protection System Components;" and C.2.4, "Aging Management Reviews for Mechanical Component External Surfaces." The staff reviewed the application to determine whether the applicant has demonstrated that the fire protection activities inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.18.2 Summary of Technical Information in the Application

Fire protection activities are comprised of condition monitoring and performance monitoring activities. These activities provide assurance that a fire will not prevent the performance of necessary safe shutdown functions. The fire protection activities use both direct visual examination and indirect flow testing to detect flow blockage, loss of material, cracking, and changes in material properties. The fire protection activities are designed to minimize both the probability and consequences of postulated fires through a defense-in-depth philosophy.

Plant Hatch fire protection activities credits Appendix B of the Fire Hazards Analysis (FHA) and includes passive long-lived components in water-based and gas-based fire suppression systems. In addition, the fire pump diesel fuel oil supply system (tanks and piping) and various fire rated assemblies are also included.

The water-based fire protection header loop piping is flushed regularly and the fire pump casings are visually inspected and operationally tested. The sprinklers are visually inspected and open-head sprinklers and nozzles are flow tested using air. Fire water tank internals are inspected for localized and general pitting, average dry film thickness and general condition of the protective coating. Sizes and depth of the pits are recorded. Interior surfaces are cleaned as required to facilitate inspection. Fire pump diesel fuel oil supply and various gaseous fire suppression system components are visually inspected and performance tested. In-scope fire-rated assemblies are visually inspected periodically.

3.1.18.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the fire protection activities program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

Fire protection activities are applied to the following system:

X43 - Fire Protection System

which includes the following commodity groups:

- water-based fire suppression systems
- fire protection diesel fuel oil supply system
- compressed gas based fire suppression systems
- fire barriers for preventing fire propagation
- external surfaces exposed to an inside environment
- external surfaces exposed to an outside environment

The staff requested in RAI 3.1.18-10(b) that the applicant identify the long-lived components in the water-based and gas-based fire suppression systems. In its response, the applicant stated

that, “all fire rated penetration seals, excluding those inside the radwaste building, are included in the scope of license renewal.” The staff does not agree that the fire protection components located in the radwaste building can be excluded from the scope of license renewal. A full description of Open Item 2.3.4.2-1 is provided in Section 2.3.4 of this SER.

Preventive or Mitigative Actions

Section A.2.1 of the LRA states that, for water-based fire suppression system components, the fire protection activities prevent or mitigate loss of material by using system flushes to remove undesirable material from the system. However, the operability of the automatic wet-pipe sprinkler systems, which are required for compliance with 10 CFR 50.48, were not discussed. In response to RAI 3.1.18-7, in which the staff notified the applicant of this omission, the applicant stated that, “unobstructed water flow from the header test valve demonstrates that sprinkler heads and piping are not clogged from corrosion product debris.” The staff does not agree with this statement since (1) the arrangement of the test header at the most distant point in the sprinkler system is usually located in the fire suppression piping, which is along the path of least water resistance, and (2) the sprinkler heads are located along the smaller branch line piping and, as a result of their orientation, are typically never exposed to the flow of water during the routine testing of the test header. Since there is little or no flow in the branch lines during testing, the water in these lines remains stagnant and sediment from the raw water, which flows to the header test connection, continues to collect in the smaller branch line piping. This may result in blockage and corrosion of the branch line piping and the sprinkler heads at accelerated rates. The staff has addressed this issue in Generic Letter 89-13, “Service Water Problems Affecting Safety-Related Equipment.” The staff requests that the applicant discuss the specific considerations for addressing this aging mechanism in the automatic wet-pipe sprinkler systems. This is part of Open Item 3.1.18-1.

Parameters Inspected or Monitored

The applicant states that surveillance and inspection of fire protection systems and components are performed in accordance with Appendix B of the FHA. Fire protection activities provide for visual inspection or performance testing for the water-based fire suppression system components and the diesel fuel oil system components. For the water-based fire suppression system, diesel fire pumps are visually inspected and operationally tested on a regular schedule, the fire water storage tank internal surfaces are periodically inspected, the sprinkler nozzles are visually inspected and air-flow-tested on a regular schedule, and valves are cycled to verify functionality. Visual inspections and performance testing of the fire protection diesel fuel oil supply system are conducted on a regular basis to determine degradation of fuel oil within the supply lines connecting the storage tank and diesel engine. Visual inspections and performance testing of the compressed gas fire suppression systems and inspections of the insulation installed on the CO_2 storage tanks are conducted on a regular basis. Visual inspections are performed on fire penetration seals, in-scope cable tray enclosures and fire doors. Exterior coatings or paint are inspected per the industry guidance reflected in the protective coatings program.

The staff finds that the parameters inspected or monitored under this aging management program are adequate to ensure that aging effects will be identified for disposition through the corrective actions program.

Detection of Aging Effects

The applicant states that flow blockage, loss of material, cracking, and changes in material properties are detected directly by visual examinations of component surfaces and indirectly through the use of flow functional testing.

With regard to the inspection frequency of fire system components, the applicant lists in Section B.2.1 of the LRA the different inspection intervals for the water-based fire protection systems, fire protection pump diesel fuel oil supply system, compressed gas based fire suppression systems, fire penetration seals, cable tray enclosures, and fire doors. In addition to the systems listed above, the applicant describes a one-time inspection called the “Sprinkler Head Inspections” that will be performed at or before the start of the extended period of operation for closed sprinkler heads within the scope of license renewal. In RAI 3.1.18-9, the staff requested that the applicant provide justification for the absence of enhanced inspection programs for the sprinkler heads, which do not have a design life that covers the period of extended operation. In response the applicant stated that, “in general, enhanced inspection programs are deemed unnecessary because the existing programs adequately manage the aging effects of concern,” and that using the guidelines of the National Fire Protection Act (NFPA) Code 25, “Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection,” a one-time sprinkler heads inspection is to be performed for in-scope sprinkler heads.” The staff does not agree that a one-time inspection is sufficient for the sprinkler heads and recommends that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25, Section 2.3.3.1, “Sprinklers.” Section 2.3.3.1 states that “where sprinklers have been in place for 50 years, they shall be replaced, or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing.” It also contains guidance to perform this sampling every 10 years after the initial field service testing. In addition, the staff has notified the nuclear industry, through recent information notices, about the potential failures associated with sprinkler heads. These information notices include IN 99-03, “Potential for Failure of the ‘Model GB’ Series Sprinkler Heads with ‘O-Ring’ Water Seals;” IN 99-28, “Recall of Star Brand Fire Protection Sprinkler Heads;” and IN 97-72, “Potential for Failure of the Omega Series Sprinkler Heads.” Problems with seals leaking and sprinkler heads failing to actuate are typically not detectable through the performance of existing visual inspections. Therefore, the staff requests that the applicant expand the scope of its inspections to include the 10-year inspection intervals that are recommended in NFPA 25 or provide additional justification for the applicant’s proposed inspection interval. This is part of Open Item 3.1.18-1.

Monitoring and Trending

The applicant states that the results of fire protection system tests and inspections are documented in accordance with procedural requirements. In addition, the corrective actions program is used to monitor and trend fire protection deficiencies and to implement timely corrective actions. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

Acceptance Criteria

The applicant states that significant degradation of components managed by this aging management program are noted and corrective actions are implemented based on the corrective actions program. Acceptance criteria for each test or inspection is specifically stated in plant procedures and includes the following: system frictional pressure drop; adequate air flow; detection of leaks present; sampling for water, sediment, and other oil contaminants; and CO_2 tank pressure, general condition, and pressure boundary leakage.

Based on the discussion above and the operating history of this aging management program, the staff finds that the acceptance criteria established in plant procedures reasonable to detect aging effects which were evaluated by the corrective actions program before failure occurred.

Operating Experience

For the water-based fire suppression systems, deficiencies included leaking piping, deterioration of coatings within the fire water storage tank, and fouling of lines due to corrosion buildup. These were identified during testing and inspection as required by the fire protection activities or normal walk down activities.

Deficiencies managed in the fire protection diesel fuel oil supply system included clogging of strainers with sediment and degraded fuel oil. Fire protection activities provided corrective actions for this deficiency. These deficiencies were determined not to be significant since no loss of intended function occurred. Deficiencies of the external surfaces are managed by the applicant's protective coatings program.

The staff concludes that the operating experience, to date, supports the attributes of the fire protection activities.

3.1.18.4 Conclusions

The staff has reviewed the aging management program, fire protection activities, described in the following sections of the LRA: A.2.1, "Fire Protection Activities;" B.2.1, "Fire Protection Activities;" C.2.3, "Aging Management Reviews for Fire Protection System Components;" and C.2.4, "Aging Management Reviews for Mechanical Component External Surfaces." Upon satisfactory resolution of Open Items 2.3.4.2-1 and 3.1.18-1, the staff concludes that the fire protection activities program will adequately manage the identified aging effects for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.19 Flow Accelerated Corrosion Program

3.1.19.1 Introduction

The applicant described its flow-accelerated corrosion (FAC) program in Sections A.2.2, "Flow Accelerated Corrosion Program" and B.2.2, "Flow Accelerated Corrosion Program" of the LRA. It also included relevant materials from Section 3.2.1, "Reactor," Section 3.2.3, "Engineering Safety Features (ESF) System" and Section 3.2.5, "Steam and Power Conversion" of the LRA. These sections address aging effects of the components in reactor, engineering safety features,

and steam and power conversion systems. The components in these systems belong to two commodity groups: one representing Class 1 carbon steel components within the reactor water environment and the other, non-Class 1 carbon steel components within the reactor water environment. Both of these commodity groups contain components that are subject to aging effects managed by the FAC program. The objective of this program is to ensure that the damage caused by flow-accelerated corrosion will not cause component failures. This objective is accomplished by predicting the rate of degradation of components and taking corrective actions once the degradation is detected.

The staff reviewed the applicant's description of the program in Sections A.2.2 and B.2.2 of the LRA and relevant material in other referenced sections of the LRA to determine whether the applicant has demonstrated that the program will adequately manage the effects of aging caused by FAC in the plant during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.19.2 Summary of Technical Information in the Application

In the LRA the applicant has identified the following systems which contain the components that are affected by FAC:

- nuclear boiler system
- high pressure coolant injection system
- reactor core isolation system
- main condenser

The applicant identified loss of material by FAC as the aging effect for carbon steel components exposed to reactor water.

In the LRA, the applicant identified a FAC program for managing the aging effects caused by FAC. The program is based on EPRI recommendations for effective control of FAC. For license renewal, the applicant will enhance the existing program by adding components in certain systems which are already included in the FAC program. For Unit 2, these systems will consist of portions of the radioactive decay holdup volume (main steam and steam line drains, and condensate drains). Also, it will enhance examination methods and frequencies for the components, such as smaller-than-two-inch piping, whose FAC wall thinning could not be predicted by the computer code used in the program. Examinations of these components will be based on industry and plant-specific operating experience as opposed to computer modeling. The applicant concluded that this enhanced program will adequately manage aging effects in the components affected by FAC.

3.1.19.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the FAC program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The components in the systems affected by FAC are made of carbon steel. This material, when exposed to the environment of moving single or two-phase reactor water with relatively low oxygen content and high temperature, corrodes at rates higher than if it were in contact with a stagnant fluid. The resulting loss of material produces thinning walls in the affected components. To prevent component failure, loss of material has to be managed. The staff finds that there is reasonable assurance that this mode of degradation is the only plausible aging effect related to FAC for aging management considerations.

The applicant has a program for managing aging effects due to FAC. The program is based on the EPRI recommendations, specified in Report NSAC-202L "Recommendations for an Effective Flow-Accelerated Corrosion Program," and on the associated CHECWORKS computer code. The program predicts, detects and monitors flow accelerated corrosion wear in high energy carbon steel piping in the nuclear boiler system, high pressure coolant injection system, reactor core isolation system, and main condenser. It includes determination of the extent of wall thinning in the FAC-affected components and specifies repair or replacement of the components with wall thickness not meeting the acceptance criteria.

Program Scope

The applicant will enhance the existing program during the period of extended operation, starting midnight August 6, 2014, for Unit 1 and midnight June 13, 2018, for Unit 2. The enhancement includes additional components for inspection, and adds an inspection method for the components which could not be inspected by the method presently existing in the program. The staff finds that the enhanced scope of the program will be adequate for managing loss of material due to FAC.

Preventive and Mitigative Actions

FAC is controlled by the geometry, hydrodynamic conditions and chemistry of the system. The first two attributes cannot be controlled, but water chemistry control can be achieved by reducing the oxygen content in the water environment. Such a water chemistry control program to mitigate the aging effects due to FAC is not implemented in the Plant Hatch units. The FAC program is a program designed to monitor the aging effect due to FAC prior to loss of intended function. The staff agrees that the FAC program is not a program intended to prevent or mitigate the effects associated with FAC. Instead the program is designed to monitor the aging effects due to FAC. The staff concludes that the program will provide assurance that FAC will be adequately monitored.

Parameters Monitored or Inspected

The FAC program monitors the effects of FAC by measuring wall thickness of the components exposed to the environment favoring FAC. Analytical models are used to predict wall thinning in piping systems susceptible to FAC on the basis of the specific plant data, including material of construction, chemistry, and hydrodynamic and operating conditions. The subsequent examination of the selected components is made by visual, ultrasonic, or radiographic techniques. The staff finds this methodology adequate for detecting aging effects due to FAC.

Detection of Aging Effects

Wall thickness is measured by ultrasonic testing or, in the case of small-bore pipes, by radiography. The staff finds these to be standard, well developed techniques that will produce reliable results.

Monitoring and Trending

Using the methods stated above, the applicant will be able to evaluate the rate at which component wall thinning by FAC is occurring. The CHECWORKS computer program contains a database that maintains inspection data which can be used for that purpose. Trending the data will permit determination of the timing for future inspections. Also, if degradation is detected such that the wall thickness may reach a value below the minimum allowed by the acceptance criteria, the component will be repaired or replaced, and additional examinations will be performed of the components in the adjacent areas to bound the damaged component. The staff finds adequate the monitoring and trending method and subsequent actions.

Acceptance Criteria

The criteria for component replacement are based on allowable minimum wall thickness, determined by the design code of record. If the predictive methods indicate that a component will reach its minimum allowable wall thickness before the next inspection interval, proper corrective actions will be undertaken. The staff finds the acceptance criteria adequate.

Operating Experience

The applicant monitors the FAC-related developments occurring in the industry. This is accomplished through contacts with EPRI and review of the information generated by the industry. Additionally, EPRI NSAC-202L provides lessons learned from years of industry-wide operating experience which could be used to improve the FAC program. A review of plant data for the past five years has revealed FAC damage in small bore piping of the HPCI and RCIC main steam supply drain to the condenser. The damaged components were replaced with material not susceptible to FAC. Also, as a result of FAC program inspection and corrective action implementation, the high-pressure drain manifold was replaced with chrome-moly piping. The staff finds that plant experience has indicated that the FAC program is successful in managing aging caused by FAC.

3.1.19.4 Conclusions

The staff has reviewed the information in Section A.2.2, “Flow Accelerated Corrosion Program” and B.2.2, “Flow Accelerated Corrosion Program,” of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the flow accelerated corrosion program will adequately manage aging effects caused by flow accelerated corrosion for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.20 Protective Coatings Program

3.1.20.1 Introduction

The applicant described the protective coatings program in Sections A.2.3 and B.2.3 of the LRA. The staff reviewed the application to determine whether the applicant has demonstrated that the protective coatings program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.20.2 Summary of Technical Information in the Application

The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures.

The protective coatings program will be expanded to include the external surfaces of carbon steel commodities in-scope for license renewal that are exposed to inside, outside, submerged, and buried environments, as made accessible. Portions of multiple systems will be included, based upon plant-specific operating experience and conditions. Affected systems will include, but may not be limited to, the nuclear boiler, standby liquid control, residual heat removal, residual heat removal service water, core spray, high pressure coolant injection, and reactor core isolation cooling. Certain portions of the post-accident radioactive decay holdup, PSW, instrument air, drywell chilled water, drywell pneumatics, standby gas treatment, nitrogen inerting, fire protection, and diesel fuel oil systems, as well as piping supports, raceway supports, and building structural steel will also be included. The affected components in these systems will be piping, valves, pumps, bolts, tanks, and structural steel.

The protective coatings program will be revised to require periodic inspections of in-scope components to ensure that they are properly coated and free of significant age-related degradation. Coated surfaces of certain components, including those normally inaccessible but made accessible due to maintenance or other activities, will also be inspected when they become accessible.

Program expansions and revisions will be implemented by midnight August 6, 2014, for Unit 1 and common system components, and midnight June 13, 2018, for Unit 2.

3.1.20.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the protective coatings program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures.

The systems where the protective coatings program is applied are:

B21 - Nuclear Boiler
C41 - Engineered Safety Features
C11 - Control Rod Drive
E11 - Residual Heat Removal
E21 - Core Spray
E41 - High Pressure Coolant Injection
E51 - Reactor Core Isolation Cooling
F15 - Refueling Equipment
H11 - Main Control Room Panels
H21 - In Plant Auxiliary Control Panels
L35 - Pipe Specialties
L48 - Access Doors
N61 - Main Condenser
P41 - Plant Service Water
P42 - Reactor Building Closed Cooling Water
P52 - Instrument Air
P64 - Primary Containment Chill Water
P70 - Drywell Pneumatic
R33 - Conduits, Raceways, and Trays
T23 - Primary Containment
T24 - Fuel Storage
T29 - Yard Structures
T31 - Cranes, Hoists, and Elevators
T52 - Drywell Penetrations
T54 - Reactor Building Penetrations
T41 - Reactor Building HVAC
T48 - Primary Containment Purge and Inerting
T49 - Post LOCA Hydrogen Removal
U29 - Turbine Building
W33 - Traveling Water Screens, Trash Racks
W35 - Intake Structure
X41 - Outside Structures HVAC
X43 - Fire Protection
Y29 - Yard Structures
Y32 - Off Gas Stack
Y39 - EDG Building
Y52 - Fuel Oil

Z29 - Control Building
Z41 - Control Room HVAC

The staff agrees that it is appropriate to include the systems listed above within the scope of the program.

Preventive or Mitigative Actions

The applicant states that the protective coatings program is a mitigation program designed to provide metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures. The staff agrees that a properly developed coating program that is properly implemented, constitutes a mitigative action.

Parameters Inspected or Monitored

The parameters inspected are the condition of coatings on the systems listed above. This includes bolts and base metal surfaces exposed to inside, outside, submerged, and underground environments.

The applicant stated that a protective coatings surveillance is normally performed once per operating cycle for service level I components (service level I components are used in areas inside the reactor containment where failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown). Other component surveillance is performed as determined by the protective coatings specialist, based upon trends and plant specific operating experience. The applicant stated that there will be a baseline inspection of all in-scope coated components, with the exception of buried piping, which will be inspected as available due to excavation activities. Subsequent inspection frequencies will be determined based on the results of the baseline inspection. The staff agrees that the parameters inspected are appropriate.

Detection of Aging Effects

The applicant states that aging effects are detected using visual examinations. The staff agrees that visual inspections are appropriate for bolts and base metal surfaces exposed to inside, outside, and submerged environments since this is a common and accepted practice. Visual inspections are also appropriate for buried commodities for identifying damaged or degraded coatings and any subsequent loss of material due to corrosion.

Monitoring and Trending

Results of coatings inspections are documented in accordance with Plant Hatch procedural requirements. For service level I coatings, a record will be kept concerning locations of minor deterioration, and subsequent evaluation. For all coatings, a summary of findings and recommendations for future actions will be maintained. Significant degradation identified during coatings inspections are also identified utilizing the Plant Hatch corrective actions program.

A baseline inspection of all in-scope coated components will be performed, with the exception of buried piping that will be inspected as available due to excavation activities. Subsequent inspection frequencies will be determined based on the results of the baseline inspection. The staff concludes that the monitoring and trending are adequate.

Acceptance Criteria

Multiple codes and standards were considered in the development of the plant protective coatings program. These include ANSI N5.12 – 1972, Protective Coatings (Paints) for the Nuclear Industry; ANSI N101.2 – 1972, Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities"; ASTM, Section 6, Volume 06.02, "Paints-Products and Applications, Protective Coatings, Pipeline Coatings," and AWWA C203, Coal-Tar Protective Coatings for Steel Water Pipelines - Enamel and Tape - Hot Applied," and AWWA C209, "Cold Applied Tape Coatings for the Exterior of Special Sections, Connections, and Fittings for Steel Water Pipelines."

Coatings application is not allowed to proceed until applicable solvent cleaning, removal of stratified rust, loose mill scale, non-adherent paint, weld flux and splatter, and thick edge paint feathering has been verified. Prepared steel must conform to SSPC-SP11 (Steel Structures Painting Council) visual standards SSPC-VIS3, or equivalent.

The staff has reviewed the references and agrees that the acceptance criteria in the references provides reasonable assurance that the acceptance criteria are effective in controlling the aging effect of loss of material.

Operating Experience

The applicant reviewed plant deficiency cards submitted over the past 5 years which identified many instances of coating degradation. Primarily, these deficiencies related to corrosion of carbon steel and low-alloy components in areas where the existing coating had broken down, no coating was originally applied, or wetting due to leakage had occurred.

Relevant operating experience for in-scope buried piping is limited to PSW, RHRSW, and diesel fuel oil supply piping since no credit was taken for the coatings installed on fire protection cast iron piping. A review of more than 36,000 plant deficiency cards and interviews with key personnel revealed no age related failures of piping due to coating degradation over the past 5 years.

Based on the applicant's review of plant records, the staff finds that the coating program will adequately manage the effects of aging for the period of extended operation.

3.1.20.4 Conclusions

The staff has reviewed the information in Section A.2.3, "Protective Coatings Program," and Section B.2.3, "Protective Coatings Program," of the LRA, and the applicant's responses to the staff's RAIs. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by the

protective coatings program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.21 Equipment and Piping Insulation Monitoring Program

3.1.21.1 Introduction

The applicant described its equipment and piping insulation monitoring program in Section A.2.4, C.2.4.4, C.2.4.4.1 and C.2.4.4.2 of the LRA. Supplemental information is further provided in Section B.2.4 of the applicant's October 10, 2000, submittal, which provided its responses to the staff's RAI. The equipment and piping insulation monitoring program at Plant Hatch is a condition monitoring program designed to detect insulation damage through periodic inspection of specific passive component insulation. The staff reviewed the application to determine whether the applicant has demonstrated that the program will adequately manage aging effects for the affected equipment and piping during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.21.2 Summary of Technical Information in the Application

The applicant stated that equipment and piping insulation includes insulation and associated jacketing for in-scope components installed on emergency core cooling system (ECCS), PSW and residual heat removal (RHR) service water system components. Thermal insulation serves to maintain design calculation limits, provide freeze protection, and prevent overheating of ECCS diagonals and high pressure coolant injection (HPCI) pump rooms. The metallic jackets and fasteners serve to protect the insulation from environmental attack and fix the insulation in place.

3.1.21.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the equipment and piping insulation monitoring program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

The applicant stated that for insulation, aging effects requiring management include loss of material due to wear and intrusion of water borne agents; cracking due to thermal effects and intrusion of water borne agents; and change in material properties due to compaction and settling, material separation, intrusion of water and water-borne agents, and thermal effects. The applicant also stated that the in-scope insulation jacketing components and associated fasteners are fabricated from stainless steel, galvanized steel, and aluminum alloys. The aging effects requiring management for these materials include loss of material due to general corrosion, galvanic corrosion, pitting, crevice corrosion and MIC; and cracking due to thermal fatigue.

Program Scope

The equipment and piping insulation monitoring program currently inspects insulation of piping and equipment within the scope of license renewal. The applicant stated that the program will be enhanced to include portions of the following systems that are within the scope of license renewal:

C41 - SLC
E11 - RHR and RHRSW
E21 - core spray
E41 - HPCI
E51 - RCIC
P11 - condensate transfer and storage
P41 - PSW
X43 - fire protection

The applicant indicated that program enhancements will be implemented by midnight August 6, 2014, for Unit 1, and midnight June 13, 2018, for Unit 2. The staff finds that the scope of the program will be adequate for managing the aging of insulation within the scope of license renewal.

Preventive or Mitigative Actions

The applicant stated in Section C.2.4.4 of the LRA that no reasonable method is available to mitigate potential deterioration of insulation at Plant Hatch. However, it is expected that deterioration of insulation at Plant hatch will occur slowly and would be adequately managed by a focused inspection program provided by the equipment and piping insulation monitoring program. Therefore, no program is required to prevent or mitigate aging degradation. Plant Hatch procedures contain precautions limiting climbing on pipe insulation unless specifically justified by an engineering review and evaluation. Damage is further mitigated by procedures that provide specific instructions for removal, storage, and installation of thermal and reflective insulation. The staff finds there are no preventive or mitigative attributes associated with this program. The licensee will inspect the in-scope insulation for deterioration.

Parameters Inspected or Monitored

The applicant stated that the equipment and piping insulation monitoring program will be enhanced to periodically inspect in-scope insulation, that is readily accessible, for holes, tears, compaction, material separation, wetting, missing insulation, and general deterioration. Aluminum and galvanized steel insulation jackets and their binders will be inspected for cracking and loss of material. The staff finds the examination of in-scope insulation is adequate for detecting degradation of the insulation.

Detection of Aging Effects

The applicant stated that appropriate visual inspection techniques will be used for the inspection. These techniques will include remote visual inspection using binoculars or other devices for some locations. The exterior surfaces of the insulation system are visually inspected for obvious

degradation. Exterior surfaces may consist of protective metal jacket covers that are not removed unless there is obvious degradation or evidence of a problem in the underlying insulation, such as significant corrosion or water egress from within the jacketing system. Once degradation is found, the outer metal jacket may be removed to further investigate the underlying insulation material condition. All in-scope external jackets and binders are visually inspected for holes, tears, cracks, significant corrosion, missing material, and generally deteriorated condition. When warranted by external inspection, the affected underlying insulation material is visually inspected for holes, tears, compaction, material separation, wetting, missing insulation, and generally deteriorated condition due to cracking, settling, and thermal degradation. The applicant stated that none of these conditions (holes, tears, cracks, missing material, etc.) is acceptable. If degradation is discovered, corrective action will be initiated to remedy the condition. Since the entire in-scope insulation system, to the extent it is accessible, is inspected, there is no sample size. The staff finds this approach reasonable.

Monitoring and Trending

The applicant stated that deficiencies discovered during these insulation inspections will be documented in accordance with the Plant Hatch corrective actions program. For outside insulation and jackets, the frequency of inspections is once per year. For inside insulation and jackets, all in-scope insulation is to be inspected within 2 refueling cycles of issuance of the new operating license and at least once every 10 years thereafter. The staff finds this approach reasonable.

Acceptance Criteria

The applicant stated that any unacceptable indication of corrosion or insulation damage will be evaluated and, if warranted, additional inspections will be performed. Unacceptable conditions include holes, tears, cracks, missing material, etc. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program. The applicant stated that the plant procedures specify the acceptance criteria for the equipment and piping insulation, including insulation jackets. The staff concurs with the applicant that these criteria will ensure that degraded insulation will be managed properly.

Operating Experience

A review of plant deficiency cards over the past 5 years did not identify any significant age-related degradation in insulation or insulation jacketing for the components within the scope of license renewal. The applicant stated that several deficiencies were identified related to damaged, torn, or missing insulation and jackets. These areas were localized, generally attributed to mechanical damage, and not deemed to significantly impact thermal performance of the insulated system. Only one record that related to generally deteriorated insulation was discovered. This deterioration was confined to a small area and was not determined to significantly affect the thermal performance of the insulated system. The staff finds that, based on the applicant’s operating history, that the equipment and piping insulation monitoring program will adequately manage aging effects associated with insulation and jackets for the period of extended operation.

3.1.21.4 Conclusions

The staff has reviewed the information in Section A.2.4, "Equipment and Piping Insulation Monitoring Program," and Section B.2.4, "Equipment and Piping Insulation Monitoring Program. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with the insulation of piping and equipment in systems managed by this program will be adequately managed such that the insulation and jacketing will continue to perform their intended functions, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.22 Structural Monitoring Program

3.1.22.1 Introduction

SNC described its structural monitoring program in Section A.2.5 of the LRA. The applicant supplemented the description of this AMP in Section B.2.5 of the applicant's October 10, 2000 submittal. The applicant credits this inspection program with assessing the overall conditions of buildings and structures and identifies any ongoing degradation through a visual inspection process. The program monitors and assesses the condition of structures affected by aging, which may cause loss of material, cracking, flow blockage, and change of material properties. The staff reviewed the application to determine whether the applicant has demonstrated that the structural monitoring program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.22.2 Summary of Technical Information in the Application

In Section A.2.5 of the LRA and Section B.2.5 of the applicant's October 10, 2000 submittal, the applicant describes an existing aging management program, the structural monitoring program, that provides for periodic visual inspections to monitor the condition of structures, components, and commodities. The monitored structures include the switchyard, reactor buildings, turbine buildings, intake structure, main stack, diesel generator building, control building, and waste gas building. In addition, the condensate storage tank foundation and walls, plant service water valve pits, and nitrogen storage tank foundations are also monitored by the structural monitoring program. The applicant lists the specific structural components, which are fabricated from either carbon steel, stainless steel, or concrete, and inspected as part of the structural monitoring program in Sections 3.2 through 3.4 of the LRA.

The aging effects managed by the structural monitoring program are discussed in Section C.1.4 of the LRA. The structural monitoring program is relied on for management of loss of material due to general corrosion for steel structures in seismic Category I buildings, the turbine building, Category I yard structures and component supports. For concrete components (i.e., walls, beams, slabs, columns, floors, roof, underground duct runs and pull boxes, foundations) and block walls in concrete structures, the structural monitoring program is relied on for management of loss of material, cracking, and spalling due to corrosion for embedded steel, and cracking in masonry block walls. The structural monitoring program is also relied on to manage flow blockage for the plant service water pumps as well as excessive silt at the intake structure. In addition, the structural monitoring program also manages loss of adhesion, material property changes, and cracking of the reactor building joint seal and caulk sealant.

The applicant states that the structural monitoring program is patterned after the Westinghouse Owners Group Life Cycle Management/License Renewal Program. The structural monitoring program is an existing program that has been enhanced for license renewal to include the inspection of sealants in the joints between the reactor building exterior precast siding panels and seismic Category I and seismic Category II/I piping, cable trays, conduits, control room panels, auxiliary panels, and their supports. These program enhancements will be implemented by August 6, 2014, for Unit 1 and by June 13, 2018, for Unit 2.

3.1.22.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the structural monitoring program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant lists the structures, components, and commodities covered by the structural monitoring program in Section B.2.5 of the applicant's October 10, 2000 submittal. The staff finds that the scope of the structural monitoring program is acceptable since it includes a walkdown inspection of all structures and components within the scope of license renewal.

Preventive and Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The structural monitoring program requires a visual inspection of structures and components. Specifically, the applicant stated that (1) concrete structures are inspected for spalling, (2) masonry block walls are inspected for cracking, (3) steel structures and components are inspected for corrosion, (4) panel joints, seals, and sealants are inspected for loss of adhesion, material property changes, and cracking, and (5) acrylic domes on the tornado vents will be inspected for cracking. For structures located below ground or embedded, the applicant stated that when normally inaccessible structures are exposed because of excavation or modification, an examination is performed. This approach is acceptable to the staff. The staff finds the parameters monitored, such as cracking and spalling of concrete, and corrosion of steel, acceptable because they are directly related to the degradation of civil structures and components, and visual inspections are effective and adequate to detect such conditions.

Detection of Aging Effects

The aging effects that are managed by the structural monitoring program are identified through visual inspections. In response to RAI 3.1.22-5, the applicant stated that the implementing document for the structural monitoring program provides a detailed description of the walkdown procedures, acceptance criteria, evaluation of results, and checklists. In response to

RAI 3.1.22-4, the applicant stated that structural monitoring is performed by qualified personnel, using detailed checklists and inspection tools. In addition, all inspection results are documented in checklists, and noted degradation may be documented utilizing digital photography. With respect to the inspection frequency, the applicant stated that a five-year inspection frequency was established for the structural monitoring program. In addition, the applicant stated that this frequency will continue unless the conditions, environment, or noted degradation warrant a change. The intake structure is inspected every operating cycle due to humid environmental conditions; however, based on the results of future intake structure inspections, the monitoring program may go back to a five-year frequency. The applicant's operating experience to date supports the continuation of a five-year frequency for inspections. Furthermore, the staff finds that the five-year frequency is consistent with industry experience and is, therefore, acceptable.

Monitoring and Trending

The applicant did not identify any monitoring and trending activities in its description of the structural monitoring program; however, in response to RAI 3.1.22-2, the applicant stated that structures are monitored for changes in previously identified findings and for newly developed conditions. Trending of such findings is performed to predict degrading conditions and to determine the potential long-term impact of the finding. The staff finds that the monitoring and trending activities described by the applicant are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

Acceptance Criteria

The applicant did not identify any specific acceptance criteria in its description of the structural monitoring program; however, in response to RAI 3.1.22-1 the applicant identified the following criteria:

- Concrete is inspected for spalling (< 3/4" in depth and 8" in dimension), cracking (< 0.04" in width), exposed rebar which has not progressed and has not resulted in loss of cross section greater than 10%, and signs of separation or environmental degradation present in joints or joint materials.

- Masonry walls are inspected for cracks, for appropriate anchoring, for lateral supports for seismic block walls, and for evidence of damage or movement in the interfaces between the block walls and concrete floors.

- Structural steel is inspected for general corrosion (flaking rust, surface stains, spots) and localized corrosion with the presence of small diameter pitting or the presence of loose rust flakes peeling or blooming from metal surfaces.

In addition, in response to RAI 3.1.22-3, the applicant stated that the acceptance criteria for the structural monitoring program are consistent with the recommended criteria in ACI 349.3R-96, "Evaluation of Existing Nuclear Safety-Related Concrete Structures," and also include additional criteria for roof ponding, water leakage, coatings, penetration seals, etc. The applicant also stated that the results of the inspections are evaluated in accordance with the guidance given in NEI 96-03 and NRC Regulatory Guide 1.160 (Revision 2), "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The staff has not accepted the NEI 96-03 guideline for

use in license renewal (letter from Thomas T. Martin , NRC, to Thomas E. Tipton, NEI, dated October 1, 1996). NRC Regulatory Guide 1.160 endorses NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Although the staff has not accepted NEI 96-03, the staff finds that the acceptance criteria specified above are adequate to ensure that the structure and component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

Operating Experience

In Section B.2.5 of the LRA, the applicant stated that in 1996 and 1997 an initial inspection was performed to establish the baseline condition of the buildings and structures within the scope of the structural monitoring program. Areas were visually inspected and photographs were made to document any notable degradation. The applicant found that all inspected areas were within the limits of the acceptance criteria. The staff finds that the applicant's operating experience has demonstrated that the structural monitoring program has effectively maintained the integrity of the structures and components and that the effects of aging will be adequately managed during the period of extended operation.

3.1.22.4 Conclusions

The staff has reviewed the information in Sections A.2.5, "Structural Monitoring Program" and B.2.5, "Structural Monitoring Program," of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects managed by the structural monitoring program will be adequately managed so that there is reasonable assurance that the commodities and components covered by this inspection program will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.23 Galvanic Susceptibility Inspections

3.1.23.1 Introduction

The applicant described the galvanic susceptibility inspection program in Sections A.3.1 and B.3.1 of the LRA. The program is described under A.3 "New Programs and Activities" of the Final Safety Analysis Report Supplement. The program is aimed at verifying the integrity of the components subject to galvanic corrosion. The staff reviewed this section of the application to determine whether the applicant demonstrated that the effects of aging caused by galvanic corrosion will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.23.2 Summary of Technical Information in the Application

Sections A.3.1 and B.3.1 of the LRA includes a discussion of the galvanic susceptibility inspection program, which determines the acceptability of the components exposed to galvanic corrosion. This type of corrosion occurs when two electrically coupled metal surfaces characterized by different corrosion potentials are exposed to an electrolyte. In this situation, a less noble material (carbon steel for example) will corrode. The applicant has identified three types of galvanic couples at Plant Hatch: carbon steel-stainless steel, aluminum alloy-galvanized

steel and galvanized steel-stainless steel. The carbon steel-stainless steel couple exposed to an electrolyte is most conducive to galvanic corrosion since these two materials are far apart in the galvanic series. The LRA has identified some of the carbon-to-stainless steel connections (welded or flanged) exposed to corrosive environments that are susceptible to galvanic corrosion in the following systems: nuclear boiler, CRD, RHR, HPCI, RCIC, main condenser, PSW, EDG, primary containment, containment atmospheric control, and screen wash isolation. Some dissimilar metal connections of aluminum alloy-galvanized steel, and galvanized steel-stainless steel used in the CST are also susceptible to galvanic corrosion.

The applicant's galvanic susceptibility inspection program is an one-time inspection for condition monitoring that will provide objective evidence that the galvanic susceptibility is being maintained for the specific components within the scope of license renewal. Since galvanic corrosion is most likely to occur in commodities within environments that are highly corrosive (high impurity and conductivity levels), these inspections will start with the corrosive raw water environment. The galvanic susceptibility inspection will utilize a volumetric examination method for a sample population of carbon-to-stainless steel weld connections for thickness measurements using an ultrasonic or radiographic technique, or a depth gauge, where feasible, or by the removal of a specimen and conducting an analysis. This inspection may also utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI. Any unacceptable indication of loss of material will be evaluated by an engineering analysis and, if warranted, additional inspections will be performed. The results of examination will also be evaluated to determine whether the sample set should be expanded to cover other environments. The applicant will implement corrective actions through the existing Plant Hatch corrective actions program.

3.1.23.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the galvanic susceptibility program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The galvanic susceptibility inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed. In this program, the applicant has stated that it would provide for the condition monitoring of the components within the scope of license renewal to determine whether galvanic corrosion is being managed for the period of extended operation. This determination will be achieved by inspecting selected components. Samples for inspection will be selected from raw water carbon steel-to-stainless steel weld connections since these two materials are the farthest apart in the galvanic series, and therefore have the greatest potential for galvanic corrosion. Examination results will be evaluated to determine whether the sample set should be expanded to other environments. The staff finds the scope of the program to be adequate because it bounds the galvanic corrosion rates occurring in other components within the scope of license

renewal and, therefore, provides for meaningful detection of age-related damage caused by galvanic corrosion. The applicant stated that the Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018.

Preventive or Mitigative Actions

There are no activities in the galvanic susceptibility inspection program with regard to preventive or mitigative actions. The staff did not identify the need for such actions.

Parameters Inspected or Monitored

The applicant stated that the galvanic susceptibility inspections are one-time inspections that will focus on whether there is loss of material due to galvanic corrosion. Appropriate examination methods will be utilized and inspection locations will be selected for thickness measurement. The staff finds this approach to be acceptable.

Detection of Aging Effects

Volumetric examination will be conducted for a sample population of the carbon to stainless steel weld connections for thickness measurements using an ultrasonic or radiographic technique, or a depth gauge, where feasible, or by removing of a specimen and conducting an analysis. The inspection may also utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI. The wall thickness inspection of the representative sample will determine the loss of material due to galvanic corrosion and, hence, assess the impact of this aging effect on other components of the plant included in the LRA. The staff finds this to be acceptable.

Monitoring and Trending

There are no activities in the galvanic susceptibility inspection program with regard to monitoring and trending. The staff did not identify the need for such.

Acceptance Criteria

The acceptance criteria will be based on the applicable sections of the design codes. The program also requires that corrective action be taken if any unacceptable condition of loss of material is detected. The staff finds that, as proposed by the applicant, an engineering analysis followed by implementation of specific corrective actions specified by the site-controlled corrective action program, will provide an acceptable technical basis for management of the aging effects caused by galvanic corrosion.

Operating Experience

The applicant conducted a review of records dating back 5 years on the components within the scope of license renewal to determine deficiencies related to the loss of material due to galvanic corrosion and did not find any deficiency.

3.1.23.4 Conclusions

The staff has reviewed the information in Sections A.3.1 and B.3.1, “Galvanic Susceptibility Inspections” of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the galvanic susceptibility inspection program will adequately manage the aging effects due to galvanic corrosion of components within the scope of license renewal for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.24 Treated Water Systems Piping Inspections

3.1.24.1 Introduction

The applicant described its treated water systems piping inspection program in Section A.3.2 of the LRA. Supplemental information on the inspection program is further provided in Section B.3.2 of the applicant’s October 10, 2000, submittal, which provided responses to the staff’s RAIs. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on structures and components in systems managed by this inspection program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.24.2 Summary of Technical Information in the Application

The treated water systems piping inspections will provide for condition monitoring via one-time examinations intended to provide objective evidence that existing chemistry control is managing aging in piping that is not examined under another inspection program.

The program will examine a sample population of carbon and stainless steel tubing and piping in the treated water systems. The results of the sample population examinations will be recorded and evaluated, and subsequent examinations will be conducted where evaluation results warrant. If significant degradation is noted, the sample set may be expanded.

The applicant stated that the treated water system piping inspections program will be conducted using techniques appropriate for piping examination and trending. The specific sample population, examination methods and acceptance criteria will be defined in the inspection and trending procedures.

3.1.24.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant’s LRA regarding the applicant’s demonstration of the treated water systems piping inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that portions of the following systems are included within the scope of this program:

B21 - Nuclear Boiler
B31 - Reactor Recirculation
C11 - Control Rod Drive
C41 - Standby Liquid Control
E21 - Core Spray
E41 - High Pressure Coolant Injection
E51 - Reactor Core Isolation Cooling
N32 - Main Turbine Auxiliaries
P11 - Condensate Storage and Transfer
P42 - Reactor Building Closed Cooling Water
P64 - Primary Containment Chilled Water
R43 - Emergency Diesel Generator Auxiliaries
T23 - Primary Containment
T48 - Containment Atmospheric Control System

The applicant stated that the Unit 1 inspections will be performed on or after August 6, 2009, but before midnight August 2014. The Unit 2 inspections will be performed on or after June 13, 2013, but before midnight June 13, 2018. The staff finds the scope of the program adequate.

Preventive or Mitigative Actions

The applicant stated that the treated water systems piping inspections will be condition monitoring activities which utilize visual inspections to identify unacceptable age-related degradation within the applicable systems. Therefore, there are no preventive or mitigative attributes associated with this program nor did the staff identify a need for such.

Parameters Inspected or Monitored

The applicant stated that these one-time inspections will focus on determining whether there has been loss of material from, or cracking in, Class 1 and non-Class 1 carbon and stainless steels within the reactor water, torus water, demineralized water, closed cooling water, and borated water environments. Appropriate examination methods will be utilized, and inspection locations will be selected, based on engineering judgement. The selection will include areas predicted to be most susceptible to corrosion, erosion-corrosion, erosion, and cracking. The staff finds the parameters inspected acceptable because appropriate examination methods will be employed to detect loss of material and cracking.

Detection of Aging Effects

The applicant stated that a one-time visual inspection of the sample set will be conducted using the best available examination method for the inspected component. Inspections may utilize an examination method similar to that described for VT-1 in ASME Section XI, Paragraph IWA-2210. Where possible and practical, accessible components may be inspected using

volumetric examination methods. The staff finds that the detection of aging effects before there is a loss of intended function can be reasonably expected from the inspection program because of the adequate inspection scope, technique, and frequency. Satisfactory operating experience to date also supports this conclusion

Monitoring and Trending

The applicant stated that periodic monitoring and trending of degradation for inspection locations will be established provided that the one-time inspection results indicate a concern that components may not be able to perform their intended function during the period of extended operation. Failures will be documented in accordance with the Plant Hatch corrective actions program. The staff finds this approach acceptable because it will provide predictability of the extent of degradation so timely corrective or mitigative actions are possible.

Acceptance Criteria

The applicant stated that any unacceptable indication of corrosion will be evaluated by further engineering analysis. Component wall thickness acceptability will be based on the component design code of record. Cracks identified via visual examinations shall be further inspected via volumetric examinations for evaluation by engineering analysis. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program.

The applicant stated that if components do not meet the acceptance criteria defined in the inspection procedure, they will be evaluated, repaired, or replaced prior to return to service. If a significant number of the initial sample population fail to meet the acceptance criteria, the sample population may be increased. If the applicable acceptance criteria are met for the sample population, expansion of the sample set will not be necessary. The staff finds this approach acceptable because any indication of components not meeting the pre-established acceptance criteria would require the applicant to implement corrective actions.

Operating Experience

The treated water system piping inspections will be a one-time activity. Thus, there is no operating experience directly associated with the treated water system piping inspection. The applicant stated, however, that a review of plant deficiency cards submitted over the past five years revealed no significant deficiencies in the in-scope treated water components due to age-related degradation.

3.1.24.4 Conclusions

The staff has reviewed the information in Sections A.3.2, ”Treated Water Systems Piping Inspections,” and B.3.2, ”Treated Water Systems Piping Inspections,” of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components in systems managed by this program will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.25 Gas Systems Component Inspections

3.1.25.1 Introduction

The applicant described the gas systems components inspections program in Sections A.3.3 and B.3.3 of the LRA. The program is described under A.3 "New Programs and Activities" of the Final Safety Analysis Report Supplement. The program verifies that age-related degradation is not inhibiting component function in gas-bearing systems within the scope of license renewal. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging caused by the humid and wetted gas internal environment will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.25.2 Summary of Technical Information in the Application

Section B.3.3 of the LRA describes the gas systems component inspection program, which implements condition monitoring with regard to age-related degradation of components having an internal environments of humid or wetted gas. Loss of material as a result of general corrosion in carbon steel, material property changes, and cracking in low-alloy and stainless steels are also likely to occur due to contaminants such as chlorides and oxygen in the presence of moisture. The applicant has included portions of the following systems within the scope of the gas systems component inspection program: nuclear boiler (including safety relief valve tail pipes to the torus), CRD, RHR, HPCI, RCIC, sampling, EDG, primary containment, reactor building HVAC, standby gas treatment, primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fuel oil, and control building HVAC.

The applicant's inspection program is a one-time inspection for condition monitoring that will provide objective evidence that the aging effects predicted for systems with gas as the internal environment are being adequately managed during the period of extended operation. Since loss of material due to general corrosion and cracking are associated with the presence of moisture and/or liquid pooling or wet/dry cycling, a sample population of components exposed to such an environmental condition at various temperatures will be inspected. In addition, certain external surfaces in gas-bearing components of the EDG, outside structure HVAC, and control building HVAC will also be included in the sample population. The gas systems component inspection will utilize an examination method similar to that described for VT-1 visual examination of the ASME Code, Section XI, or a volumetric examination for condition monitoring. Any unacceptable indication of corrosion will be evaluated by engineering analysis. The applicant will implement corrective actions through the existing Plant Hatch corrective action program.

3.1.25.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the gas systems piping inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

Gas systems component inspections are one-time inspections of a given sample that are intended to provide objective evidence that the applicable aging effects are being adequately managed. The applicant has stated that it would provide for condition monitoring of the components in the systems with gases as internal environment within the scope of license renewal to determine whether age-related degradation is being managed for the period of extended operation. This determination will be achieved by performing inspections of selected sample populations of gas system components exposed to moisture and/or liquid pooling or wet/dry cycling at various temperatures. The applicant has included portions of the following systems within the scope of the program: nuclear boiler (safety relief valve tail pipes to the torus), CRD, RHR, HPCI, RCIC, sampling, EDG, primary containment, reactor building HVAC, standby gas treatment, primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fuel oil, and control building HVAC. For Unit 1, the inspection will be performed on or after August 6, 2009, but before midnight August 6, 2014. Unit 2 inspection will be performed on or after June 13, 2013, but before midnight June 13, 2018. The staff finds the scope of the program to be acceptable because it covers the systems within license renewal that are susceptible to the aging effects of loss of material and cracking caused by the humid and wetted gas internal environments.

Preventive or Mitigative actions

There are no preventive or mitigative attributes with this program. The staff did not identify the need for such attributes.

Parameters Inspected or Monitored

The gas systems component inspection will primarily ensure that the component wall thickness has not degraded to such an extent that the function of the component is inhibited. Appropriate examination methods will be utilized and inspection locations will be selected based on engineering judgement. The staff finds the parameters inspected to be acceptable.

Detection of Aging Effects

The inspection will utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI, or a volumetric examination for condition monitoring. For those stainless steel components that normally operate at temperatures above 140°F, and that contain wetted gases, volumetric examination may be used as part of the inspections to detect the presence of stress-corrosion cracking. The staff finds the method of detection of aging effects to be acceptable.

Monitoring and Trending

There are no monitoring and trending attributes with this program. The staff did not identify the need for such attributes.

Acceptance Criteria

The acceptance criterion will be based on the applicable sections of the design codes. The wall thickness inspection of the representative sample will determine the loss of material due to general corrosion and assess the impact of this aging effect on other components in the balance of the plant included in the LRA. The program also requires that corrective actions be taken if any unacceptable indication of corrosion is detected. The staff finds that, as proposed by the applicant, an engineering analysis followed by implementation of specific corrective actions, as specified by the site-controlled corrective action program, will provide an acceptable technical basis for the management of the aging effects in the gas systems components. The staff finds the acceptance criteria to be satisfactory.

Operating Experience

The applicant reviewed records dating back 5 years on the in-scope gas system components, to determine deficiencies that inhibited component function, and did not find any deficiencies. However, because of the possibility of occurrence of this type of age-related degradation, it established a one-time inspection.

3.1.25.4 Conclusions

The staff has reviewed the information in Sections A.3.3 and B.3.3, “Gas Systems Component Inspection” of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the inspection program will adequately manage aging effects associated with the gas system components in a humid and wetted environment for the period of extended operation., as required by 10 CFR 54.21(a)(3).

3.1.26 Condensate Storage Tank Inspection

3.1.26.1 Introduction

The applicant described its condensate storage tank (CST) inspection in Sections A.3.4 and B.3.4 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the structures and components managed by the condensate storage tank inspection will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.26.2 Summary of Technical Information in the Application

The applicant stated in the LRA that the condensate storage tank (CST) inspection is a one-time condition monitoring inspection of each CST designed to provide objective evidence that no unacceptable degradation is occurring. The internal surfaces of each CST will be examined to verify that age-related degradation is not occurring. The examination will focus on the standpipes and the connections between aluminum standpipes and galvanized steel flanges, since these locations would be the most susceptible to corrosion. This inspection is intended to validate the adequacy of current demineralized water chemistry controls to manage aging effects.

3.1.26.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the CST inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The CSTs are part of the condensate transfer and storage system. The staff agrees with the applicant that only those CST components required to ensure the availability of 100,000 gallons of water for HPCI and RCIC system operation are within the scope of license renewal and therefore the CST inspection. Therefore, the staff finds the applicant's scope, as indicated in the application, to be appropriate and acceptable.

Preventive or Mitigative Actions

The CST inspection is a condition monitoring activity that utilizes visual inspections to identify unacceptable corrosion within the CSTs. As such, there are no preventive or mitigative attributes associated with this program, nor did the staff identify a need for such.

Parameters Inspected or Monitored

The Plant Hatch Unit 1 CST is fabricated from aluminum alloy structural shapes, pipe, and plate. Nozzle flanges on the Unit 1 CST are fabricated from galvanized carbon steel. Visual inspection on the Unit 1 tank will focus on selected areas associated with the standpipes, associated supports, and nozzles.

The Unit 2 CST is fabricated entirely from austenitic stainless steel. Visual inspection of the Unit 2 tank will focus on selected areas associated with the standpipes, associated supports, and nozzles.

Inspection locations will be based on engineering judgement and will include areas predicted to be most susceptible to corrosion, such as weld heat affected zones and crevices. The applicant indicated that detailed visual inspections are adequate to detect localized corrosion. The applicant also stated that if significant degradation is identified, actions will be taken by the corrective actions program to repair the degraded components and implement any additional inspections that may be warranted. The staff finds that monitoring these parameters are adequate and sufficient to mitigate age-related degradation of the systems and components exposed to CST internal environments.

Detection of Aging Effects

The CST inspection will utilize visual inspection techniques, including lighting and resolution requirements, that are similar to the VT-1 provisions in ASME Code recommendations to detect unacceptable corrosion. The applicant also indicated, as stated above, that if significant

degradation is identified, actions will be taken by the corrective actions program to repair the degraded components and implement any additional inspections that may be warranted. The staff finds this approach acceptable.

Monitoring and Trending

The CST inspection is a one-time inspection, designed to validate the adequacy of the demineralized water chemistry control in minimizing corrosion. Therefore, monitoring and trending is not addressed by the applicant for this AMP, nor did the staff identify a need for such.

Acceptance Criteria

Unacceptable indications of corrosion will be further evaluated by engineering analysis, and, if warranted, additional inspections will be performed. Corrective actions, if required, will be addressed through the existing Plant Hatch corrective actions program. The staff finds this approach acceptable.

Operating Experience

The applicant indicated that, from a review of its plant deficiency records over the past 5 years, no age-related deficiencies of in-scope CST surfaces were found. The CST inspection will be a new one-time inspection activity. Therefore, there is no operating experience directly associated with the CST inspection, nor does the staff identify a need for such.

3.1.26.4 Conclusions

The staff has reviewed the information in Sections A.3.4 and Section B.3.4, "Condensate Storage Tank Inspection," of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components managed by the condensate storage tank inspection will be adequately managed so that intended functions will be maintained, consistent with the current licensing basis, for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.27 Passive Component Inspection Activities

3.1.27.1 Introduction

The applicant described the passive component inspection activities in Sections A.3.5 and B.3.5 of the LRA. The program verifies the effectiveness of preventive or mitigative programs/activities credited for aging management. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging will be monitored and adequately managed by the passive component inspection activities during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.27.2 Summary of Technical Information in the Application

In Section A.3.5 and B.3.5 of the LRA, the applicant describes the passive component inspection activities, a new program for condition monitoring inspection to confirm that, for gas-bearing in-

scope systems and components, age-related degradation is not inhibiting component function. Loss of material and cracking are the aging effects that will be monitored by the passive component inspection activities. The applicant has included portions of the following systems within the scope of the passive components inspection activities: nuclear boiler (safety relief valve tail pipes to the torus), control rod drive, residual heat removal (including buried or embedded components), high pressure coolant injection, reactor core isolation cooling, plant service water (including buried or embedded components), emergency diesel generator (starting air and engine exhaust), primary containment (including the drain lines for the drywell sump discharge), reactor building HVAC, standby gas treatment (including buried or embedded components), primary containment purge and inerting, post-LOCA hydrogen recombiners, outside structure HVAC, fire protection (including buried or embedded components), fuel oil (including buried or embedded components), and control building HVAC (including gaskets).

In Section B.3.5 of the LRA, the applicant stated that the passive component inspection activities will be a set of on-going condition monitoring inspections that will provide objective evidence that the aging effects predicted for in-scope systems are being adequately managed during the period of extended operation. The passive component inspection activities will be invoked when the normally inaccessible surfaces of these components are made available for inspection due to maintenance and other activities. The preferred inspection sites will be those locations in the in-scope components where liquid pooling or wet/dry cycling is most likely to occur during normal operation. In addition, certain external surfaces of buried or embedded components of residual heat removal, plant service water, standby gas treatment, fire protection, and fuel oil systems will also be included in the inspection. The passive component inspection activities will utilize an examination method similar to that described for VT-1 visual examination of the ASME Code, Section XI or a volumetric examination for condition monitoring and will identify aging effects prior to any loss of intended function. Any unacceptable indication of corrosion will be evaluated by engineering analysis. The applicant will implement corrective actions through the existing Plant Hatch corrective action program.

3.1.27.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant’s LRA regarding the applicant’s demonstration of the passive component inspection activities to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

In response to RAI 3.1.27-1, the applicant listed the systems and components covered by the passive component inspection activities program in Section B.3.5 of the LRA. The program provides for condition monitoring of predominantly gas bearing in-scope systems and components to confirm that age-related degradation is not inhibiting component function. In addition to piping, this activity will include the internal and external surfaces of other passive components, such as valve bodies, ducts, and strainers. Piping and valves between the drywell sump and the liquid radwaste system are also included in the scope of the passive component inspection activities. These pipes and valves serve as part of the primary containment and are not otherwise in-scope for license renewal. The passive component inspection activities will also

be used for aging management of buried piping and for gaskets associated with the control building HVAC system. The passive component inspection activities will be invoked when the normally inaccessible surfaces of these components are made available for inspection due to maintenance and other activities. The staff finds that the scope of the passive component inspection activities program is acceptable since it includes condition monitoring inspection of all in-scope systems.

Preventive or Mitigative Actions

There are no activities in the passive component inspection activities program for preventive or mitigative actions and the staff did not identify the need for such actions.

Parameters Inspected

In response to RAI 3.1.27-1, the applicant, in Section B.3.5 of the LRA, stated that the passive component inspection activities will primarily ensure that the component wall thickness has not degraded such that component function is inhibited, and for gaskets, the passive component inspection activities will inspect for the presence of cracks or degradation. The staff finds that the inspected parameters will be adequate for identifying loss of material or cracking during the period of extended operation.

Detection of Aging Effects

In Section A.3.5 of the LRA, the applicant stated that the passive component inspection activities will include a baseline examination of the in-scope components, as they become available due to normal maintenance activities. The applicant further stated that the inspection will utilize an examination method similar to that described for the VT-1 visual examination of the ASME Code, Section XI, paragraph IWA-2210, to detect corrosion of metallic components and material property changes and cracking of gaskets. The applicant also stated that liquid penetrant (PT) examinations, or other suitable methods dictated by the situation for the affected component, will be used to detect discontinuities open to the component surface. In response to RAI 3.1.27-1, the applicant, in Section B.3.5, stated that, where possible and practical, accessible components will be inspected for stress corrosion cracking using volumetric examination methods. The staff finds that the applicants's examination methods will be adequate for detecting loss of material or cracking during the period of extended operation.

Monitoring and Trending

In response to RAI 3.1.27-1, the applicant, in Section B.3.5, stated that the passive component inspection activities program will be designed to collect, report, and trend age-related data. These inspections will assist in the early discovery of aging effects so that timely corrective actions may be taken before the effects inhibit component functions. The staff finds that these monitoring activities are adequate to ensure that corrective actions will be taken prior to exceeding the acceptance criteria.

Acceptance Criteria

In response to RAI 3.1.27-1, the applicant, in Section B.3.5, stated that any unacceptable indication of corrosion will be evaluated by further engineering analysis and the component wall thickness acceptability will be based upon the component design code of record. If the gasket exhibits cracking or a change in material properties, then corrective action will be taken through the existing Plant Hatch corrective action program. The staff finds the applicant's acceptance criteria specified above are adequate to ensure that the intended functions of in-scope systems are maintained during the period of extended operation.

Operating Experience

The passive component inspection activities program is a new program; thus, the applicant did not submit plant-specific operating experience. However, in response to RAI 3.1.27-1, the applicant, in Section B.3.5, stated that its review of plant deficiency cards over the past five years showed that age-related deficiencies that inhibited component function were not written on components within the scope of passive component inspection activities. The staff finds that operating experience is satisfactorily incorporated into the development of the program.

3.1.27.4 Conclusions

The staff has reviewed the information in Sections A.3.5 and B.3.5, "Passive Component Inspection Activities" of the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that the inspection program will provide adequate assurance that in-scope components susceptible to aging effects that require management are inspected for age-related degradation during the period of extended operation.

3.1.28 RHR Heat Exchanger Augmented Inspection and Testing Program

3.1.28.1 Introduction

The applicant described its RHR heat exchanger augmented inspection and testing program in Sections A.3.6, "RHR Heat Exchanger Augmented Inspection and Testing Program;" B.3.6, "RHR Heat Exchanger Augmented Inspection and Testing Program;" and C.2.2.11, "Non-Class 1 Heat Exchanger Evaluation" of the LRA. The applicant credits this inspection and testing program with managing, in part, aging effects for a variety of components used to remove heat from the reactor vessel or suppression pool. The staff reviewed the application to determine whether the applicant has demonstrated that the RHR heat exchanger augmented inspection and testing program will adequately manage, in conjunction with other AMPs, aging effects during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.28.2 Summary of Technical Information in the Application

In Section A.3.6. and B.3.6 of the LRA, the applicant describes the RHR heat exchanger augmented inspection and testing program, which manages, in part, the aging effects on carbon steel, stainless steel, and stainless steel-clad carbon steel components exposed to multiple fluid

environments. The heat exchanger components managed by this AMP are: tubes; shell; shell nozzles and shell internals; channel assembly (including channel head, water box, and partition plate); tube sheet; and impingement plate.

3.1.28.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the RHR heat exchanger augmented inspection and testing program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The RHR heat exchanger augmented inspection and testing program is applied to the residual heat removal system, which includes components made of carbon steel, stainless steel, and stainless steel-clad carbon steel. The staff finds this scope to be appropriate and acceptable.

Preventive or Mitigative Actions

The RHR heat exchanger augmented inspection and testing program is designed to mitigate and prevent age-related degradation (flow blockage and loss of thermal performance) through inspection and cleaning of the tubes every 3 cycles. These actions prevent buildup of debris inside the tubes and the channel interior. This program satisfies one of the requirements of Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and implements guidance found in SAND 93-7070.UC-523, "Aging Management Guideline for Commercial Nuclear Power Plants - Heat Exchangers (July 1984)." The operating history shows that, as recently as 1996, leakage was detected in the heat exchangers. The staff has concerns with the leakage identified in 1996, which may have been due to vibration-induced cracking (see Open Item 3.1.28-1, below).

This program also includes the pit and diving inspection activities of the structural monitoring program. These activities provide for inspection and removal of sediment in the pump suction pit to prevent or minimize flow blockage and loss of material.

The staff finds it appropriate and acceptable to perform heat exchanger tube inspection and cleaning to prevent flow blockage and loss of thermal performance. These actions, in conjunction with the removal of sediment from the suction pit, prevent or minimize flow blockage and loss of material.

Parameters Inspected or Monitored

The LRA states that the RHR heat exchanger augmented inspection and testing program monitors loss of material, flow area reduction, and cracking. Specifically, the LRA states that visual inspections of the internal surfaces of the heat exchanger channel and shell sides are performed at scheduled intervals. In addition, eddy current testing and leak testing are performed at scheduled intervals, and whenever leaks are suspected in tubes and/or tube sheets.

The staff finds that the visual inspections of the heat exchanger channel and shell sides are adequate and appropriate for identifying and removing buildup on the tubes to manage loss of material due to general corrosion.

Detection of Aging Effects

The LRA states that the RHR heat exchanger augmented inspection and testing program currently includes visual inspection of the channel side and tube interior every three cycles and inservice inspection of the shell welds and base material at prescribed frequencies. In addition, this program will be augmented to include eddy current testing; visual inspection of the shell side of tube sheets, internals, and impingement plates; and tube and tube sheet leak testing.

The staff finds the methods discussed above appropriate and acceptable since these methods allow for early detection of aging effects.

Monitoring and Trending

The LRA states that the RHR heat exchanger augmented inspection and testing program includes visual inspection of the channel side and tube interior every three cycles. Eddy current testing will be performed at least once per 10-year cycle, and when leaks are suspected. Visual inspection of the shell side internals will also be performed once every 10-year cycle, where accessible. Tube and tube sheet leak testing will be performed whenever leaks are suspected. The bases for these frequencies is not clear (see Open Item 3.1.28-1, below).

Corrective actions are implemented through the corrective actions program and frequency of inspection or testing may be adjusted based on trends observed. The LRA further states that if the monitored parameters fall below the acceptance criteria, repair and/or replacement is performed prior to returning the component to service, unless an engineering analysis allows continued operation.

Pending satisfactory resolution of the open item below, the staff finds that the frequencies of monitoring and trending of the stated parameters are acceptable and appropriate to ensure that the aging effects of components within the scope of the program are managed

Acceptance Criteria

The LRA states that measured or recordable values of the inspected or monitored parameters shall not fall below the acceptable values for inspection locations and inspection criteria, as defined by the program. The staff requests that the applicant provide additional information with regard to the inspection locations (see Open Item 3.1.28-1, below).

Pending satisfactory resolution of the open item below, the staff finds that the acceptance criteria are adequate and appropriate.

Operating Experience

The LRA states that a review of the applicant's condition reporting database revealed one significant event in 1996. At this time, a sample taken from an RHRSW drain valve contained

nuclides and, as a result, a helium leak test and eddy current test were performed on the 1E11-B001B RHR heat exchanger. The testing identified possible leakage in nine heat exchanger tubes. Subsequent inspection revealed that, other than the leaking tubes, the tube bundle was in good condition. The nine suspected tubes were plugged. The applicant noted that dents were found at the tube-to-tube support connections of many tubes and may have been indicative of tube vibration. The staff requests that the applicant provide additional information regarding the leakage (see Open Item 3.1.28-1, below).

However, since no exact cause of the tube leakage was identified, and because the damaged areas were minor, no corrective actions were required. Eddy current testing performed on 1E11-B001A during Spring 1999 and on 2E11-B001B during September/October 1998, did not identify any significant deterioration of the tubes. No tube leaks for other RHR heat exchangers occurred during the five-year period. The staff requests that the applicant provide additional information regarding industry experience and the bases for the inspection schedule for the RHR heat exchangers (see Open Item 3.1.28-1, below).

Pending satisfactory resolution of the open item below, the staff concludes that the applicant has adequately considered the plant-specific and industry-wide operating experience related to the RHR heat exchangers in developing the RHR heat exchanger augmented inspection and testing program.

The staff is concerned about vibration-induced cracking in the RHR heat exchangers. The RHR heat exchanger augmented inspection and testing program description is unclear regarding its ability to manage vibration-induced cracking. Therefore, in order to ascertain whether this AMP is adequate to manage vibration-induced cracking, the staff requests that the applicant provide additional information. The requested information is summarized below, and is identified as Open Item 3.1.28-1.

A. The applicant should provide information on the inspection methods, frequencies, acceptance criteria, and associated bases, which are used to detect vibration-induced cracking.

B. The applicant should provide information regarding the leakage identified in 1996, including the analyses conducted that determined the cause of the leakage, the operational changes or component modifications that were instituted in response to the leakage, and additional programs which were developed and credited for managing vibration-induced cracking.

C. The LRA states that measured and recordable values of the inspected or monitored parameters shall not fall below acceptable values for defined inspection locations. The staff requests that the applicant identify the inspection locations, and the inspection criteria used to determine inspection locations, and their bases.

D. The LRA states that a sample taken from an RHRSW drain valve contained nuclides and as a result, testing was performed on one of the Unit 1 RHR heat exchangers. Dents were found at a number of tube-to-tube support connections and the dents may indicate tube vibration. The staff requests the applicant to provide the basis for its determination that the dents may have been caused by tube vibration, as opposed to

localized corrosion. In addition, the staff requests that the applicant provide information regarding industry experience related to the bases and criteria of the inspections credited in the RHR heat exchanger augmented inspection and testing program.

3.1.28.4 Conclusions

The staff has reviewed Sections A.3.6, : “RHR Heat Exchanger Augmented Inspection and Testing Program;” B.3.6, “RHR Heat Exchanger Augmented Inspection and Testing Program;” and C.2.2.11, “Non-Class 1 Heat Exchanger Evaluation,” of the LRA. Based on its review, and pending satisfactory resolution of Open Item 3.1.28-1, the staff has determined that the RHR heat exchanger augmented inspection and testing program activities will adequately manage the aging effects in the RHR heat exchangers, as required by 10 CFR 54.21(a)(3).

3.1.29 Torus Submerged Components Inspection Program

3.1.29.1 Introduction

The applicant described its torus submerged components inspection program in Section A.3.7 of the LRA. The applicant supplemented the description of this AMP in Section B.3.7 of the applicant’s October 10, 2000 submittal. The applicant credits this inspection program with managing, in part, aging effects for a variety of stainless steel and uncoated carbon steel structures and components that are exposed to the suppression pool environment. The staff reviewed the application to determine whether the applicant has demonstrated that the torus submerged components inspection program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.29.2 Summary of Technical Information in the Application

In Section A.3.7 of the LRA and Section B.3.7 of the applicant’s October 10, 2000 submittal, the applicant describes a new aging management program, the torus submerged components inspection program, that manages, in part, aging effects for various structures and components exposed to the suppression pool environment. The affected systems include the high pressure coolant injection, primary containment purge and inerting, nuclear boiler, residual heat removal, core spray, and reactor core isolation cooling. The applicant lists the specific systems, structures, and components in Section 3.2 of the LRA. These structures and components are fabricated from either uncoated carbon steel or stainless steel.

As discussed in Section C.1.2.2 of the LRA, loss of material is an applicable aging effect that may affect both carbon steel and stainless steel components through several corrosion mechanisms. These mechanisms include general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and erosion corrosion. The applicant also considers cracking to be an applicable aging effect that may affect specific stainless steel components due to stress corrosion cracking or intergranular attack. The applicant plans to implement the torus submerged components inspection program to provide direct evidence to validate the adequacy of the current suppression pool chemistry controls to mitigate corrosion-related aging effects on specific stainless steel and uncoated carbon steel structures and components. The program will be implemented by midnight August 6, 2014 for Unit 1 and midnight June 13, 2018 for Unit 2.

The suppression pool water (also called “torus water” in the LRA) contained within the torus consists of demineralized water supplied from demineralized water sources (such as the condensate storage tank). The applicant relies on chemistry controls to mitigate aging due to corrosion in structures and components exposed to the suppression pool water by controlling the water purity and composition. To supplement this water chemistry program, the applicant will implement the torus submerged components inspection program to provide direct confirmation of the effectiveness of the suppression pool chemistry controls. The applicant will perform visual inspections of accessible stainless steel and uncoated carbon steel components submerged in suppression pool water to detect evidence of loss of material and cracking.

3.1.29.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant’s LRA regarding the applicant’s demonstration of the torus submerged components inspection program to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated in Section B.3.7 of the LRA that the scope of this program included structures and components within the nuclear boiler system, residual heat removal system, core spray system, high pressure coolant injection system, reactor core isolation cooling system, and primary containment purge and inerting system. In a letter dated January 31, 2001, the applicant provided additional information regarding the program scope of the torus submerged component inspection program. The initial inspection scope will consist of a sample set of approximately 10 percent of the uncoated components located within the torus. This initial population would be biased towards the areas most likely to exhibit corrosion related degradation. These locations include austenitic stainless steel welds and weld heat affected zones, crevices, areas potentially covered by debris or sludge, and dissimilar metal connections or mating surfaces. The sample set may also include inspection points above the suppression pool water level because the “splash zone” can be a susceptible area. The sample size for subsequent inspections may be revised based on the initial inspection results. The staff considers an initial sample size of 10 percent large enough to provide a reasonable indicator of the general condition of the uncoated structures and components exposed to the suppression pool water environment. In addition, that initial sample will be biased towards those locations considered to be most susceptible to localized corrosion. The staff also finds it reasonable to revise subsequent inspections based on the results of the initial inspection. Therefore, the staff finds the scope of the torus submerged component inspection program to be acceptable.

Preventive or Mitigative Actions

There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored

The applicant performs visual inspections of specific uncoated carbon and stainless steel structures and components following the guidance for VT-1 inspections in ASME Section XI, paragraph IWA-2210, or other suitable method, as dictated by the component configuration. The staff finds visual inspections generally adequate for identifying loss of material. However, the staff finds visual inspections not sensitive enough for detecting stress corrosion cracking. In Section C.1.2.2.2 of the LRA, the applicant stated that stainless steel components in the HPCI and RCIC turbine discharge headers inside the torus may be susceptible to SCC. The staff requested that the applicant discuss how it manages this aging effect. In it's response to RAI 3.1.29-7, dated October 10, 2000, the applicant stated that the postulation that certain stainless steel components submerged in the suppression pool could experience SCC was very conservative. The staff agrees this is a very conservative assumption based on operating conditions and industry experience to date. In addition, because the function of the HPCI and RCIC turbine discharge headers is to direct exhaust steam into the suppression pool, only advanced and extensive SCC would have an impact on this function. The applicant stated that such significant cracking would be visible to the unaided eye. Based on the very unlikely occurrence of SCC or IGA, and the fact that only advanced and extensive SCC or IGA would have to be present to impact the intended functions of these particular components, the staff finds the use of VT-1 quality visual examinations to be sufficient to detect degradation before it impacts intended functions.

Detection of Aging Effects

To ensure that aging effects are identified before there is a loss of intended function, the staff relies on an adequate program scope, appropriate monitoring of parameters, and appropriate frequency interval. The program scope and parameter monitoring is discussed above. With respect to frequency, the applicant stated that the first inspections will be implemented by midnight August 6, 2014 for Unit 1, and midnight June 13, 2018 for Unit 2. These dates coincide with the end of the current operating period. The staff finds this inspection schedule acceptable. The staff did not identify a need for a specific commitment from the applicant to perform the inspection at a particular time. Recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the renewed license, the staff accepts the applicant's general commitment to complete the inspection before the current operating license expires. The environment is not particularly corrosive, and the system design robust; on this basis, the staff concludes that system intended functions should remain intact. The applicant will base subsequent inspection frequencies on the engineering evaluation of results from this first inspection. In summary, the staff finds that the torus submerged components inspection program has an adequate inspection scope, uses adequate inspection techniques, and has an adequate inspection schedule. Thus, it may be relied upon to provide reasonable assurance that aging effects will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that results from the baseline inspections will be assessed to determine the scope and the frequency of subsequent inspections. This is acceptable to the staff because it is reasonable to base the need for future inspections on the baseline inspection results.

Acceptance Criteria

The applicant stated in its letter of January 31, 2001, that any indication of corrosion, if judged to be significant by the inspection personnel, will be evaluated by an engineering analysis and, if warranted, additional inspections will be performed. The applicant indicated that inspectors are trained to question acceptability on initial identification of conditions that might warrant further evaluation or correction. Engineering evaluations of component acceptability are based upon the design code of record, if applicable. The staff finds this approach reasonable and consistent with current industry practice and therefore acceptable.

Operating Experience

The torus submerged components inspection program is a new program; thus, the applicant did not submit plant-specific operating experience. However, industry experience to date supports the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program. In addition, the applicant has been performing regular inspections of the torus as part of its protective coatings program and did not identify any significant degradation due to corrosion.

3.1.29.4 Conclusions

The staff has reviewed the information in Sections A.3.7 and B.3.7, "Torus Submerged Components Inspection Program" of the LRA. The staff concludes that the applicant has demonstrated that the torus submerged components inspection program will adequately manage, as a supplement to the suppression pool chemistry controls, aging effects associated with the suppression pool water environment for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.30 Insulated Cables and Connections Aging Management Program

3.1.30.1 Introduction

The applicant described its insulated cables and connections aging management program in a letter dated January 31, 2001. The staff reviewed the letter to determine whether the applicant has demonstrated that the insulated cables and connections aging management program will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(c).

3.1.30.2 Summary of Technical Information in the Application

In the letter dated January 31, 2001, the applicant described the insulated cables and connections aging management program as a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connections within the scope of license renewal during the period of extended operation. The scope of this program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in an adverse, localized environment which is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment.

3.1.30.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the relevant sections of the applicant's LRA regarding the applicant's demonstration of the insulated cables and connections AMP to ensure that the applicable component aging effects will be managed so that system intended functions will be maintained consistent with the CLB for the period of extended operation.

Program Scope

The applicant stated that program includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the primary containment structure, reactor building, radwaste building, diesel generator building, turbine building, control building, intake structure, and main stack, which could be subject to applicable aging effects from heat or radiation. This program does not include cables and connections that are in the 10 CFR 50.49 Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

On the basis of the information provided in the letter dated January 31, 2001, the staff concludes that the applicant adequately identified the accessible and inaccessible locations for insulated cables and connections within the scope of the aging management program.

Preventive or Mitigative Actions

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect.

Inaccessible insulated cables and connections will be tested. The specific type of test performed will be determined prior to each test.

The staff finds that the different methods used for accessible and inaccessible cables and connections to be sufficient to detect degradation before it impacts intended functions.

Parameters Inspected or Monitored

The applicant stated that change in material properties of the conductor insulation is the applicable aging effect and changes in material properties managed by this program are those caused by severe heat or radiation (conditions that establish an adverse, localized environment). The staff finds the visual examinations and testing to be sufficient to detect changes in material properties before they result in degradation that may impact intended functions.

Detection of Aging Effects

Accessible insulated cables and connections installed in adverse, localized environments will be inspected at least once every 10 years. Inaccessible cables and connections will be tested at least once every 10 years. Samples may be used for this program and if used, an appropriate sample size will be determined prior to the inspection or test.

Following issuance of a renewed operating license for Plant Hatch, the initial inspections and tests will be completed by the end of the initial license term for each unit (August 6, 2014 for Unit 1 and June 13, 2018 for Unit 2).

The staff finds that the insulated cables and connections aging management program has an adequate inspection schedule regarding the detection of aging effects such that it provides reasonable assurance that the aging effects will be detected before there is a loss of intended function.

Monitoring and Trending

The applicant stated that for accessible and inaccessible insulated cables and connections, the monitoring and trending activities will be defined by the specific type of inspection (visual or testing) to be performed. Plant Hatch procedures require that deficiencies discovered during the performance of the program activities be documented in accordance with the condition reporting process. Chapter 17 of the Unit 2 FSAR is part of the Plant hatch Quality Assurance (QA) program and describes the corrective action process.

The staff finds that it is acceptable to base the monitoring and trending activities on the specific type of inspection to be performed on the accessible and inaccessible insulated cables and connections.

Acceptance Criteria

The applicant stated that for accessible insulated cable and connections installed in adverse, localized environments, the acceptance criterion is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effects may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. For inaccessible insulated cables and connections, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific type cable to be tested.

The staff concludes that the applicant has identified acceptance criteria for accessible insulated cables and connections and will identify acceptance criteria for inaccessible insulated cables and connections (depending on the test and cable chosen) which will support the detection and evaluation of aging effects such that the intended functions for the insulated cables and connections will remain intact.

Corrective Actions

The applicant stated that when the acceptance criteria are not met on accessible and inaccessible insulated cables and connections, further investigation by engineering will be performed. This will be done in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocation or replacement. Specific corrective actions will be implemented in accordance with the Corrective Actions Program which applies to all structures and components within the scope of the insulated cables and connections aging management program. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible insulated cables and connections.

The staff finds the CAP and corrective actions as described above and in Chapter 17 of the Unit 2 FSAR to be acceptable for managing aging for components within the scope of the insulated cables and connections aging management program.

Confirmation Process, Administrative Controls, and Operating Experience

The applicant stated that the confirmation process will ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective. For accessible and inaccessible insulated cables and connections, the confirmation process will be defined by the specific type of inspection or test to be performed.

Administrative controls will provide a formal review and approval process. For accessible and inaccessible insulated cables and connections, the administrative controls process will be identified by the specific type of inspection or test to be performed.

The Corrective Actions Program provides for evaluation of aging effects and significant operating events and requires that reasonable actions be taken to enhance programs and activities to prevent future occurrences.

The staff finds that the Corrective Actions Program satisfies the elements of the confirmation process, the administrative controls, and operating experience such that it provides reasonable assurance that the insulated cables and connections program will adequately manage the effects of aging during the period of extended operation.

3.1.30.4 Conclusions

The staff has reviewed the information in the letter dated January 31, 2001, which described a new program “Insulated Cables and Connections Aging Management Program.” On the basis of the information provided in the letter, the staff concludes that the applicant has demonstrated that the insulated cables and connections inspection program (visual and test) will adequately manage the aging effects associated with insulated cables and connections for the period of extended operation, as required by 10 CFR 54.21(a)(3).

AGING MANAGEMENT PROGRAMS - CONCLUSION

The staff has reviewed the 30 AMPs included in Sections A, B, and C of the applicant's LRA. On the basis of its review, pending satisfactory resolution of Open Items 3.0-1, 3.1.1-1, 3.1.3-1, 3.1.11-1, 3.1.13-1, 3.1.17-1, 3.1.18-1, and 3.1.28-1, the staff concludes that the applicant has demonstrated that the effects of aging associated with structures and components within the scope of license renewal and subject to an AMR, will be adequately managed so that the intended functions will maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Reactor Coolant System

3.2.1 Introduction

The applicant described its AMR of the reactor vessel, reactor vessel internals, and reactor coolant systems for license renewal in Sections 3.0, "Aging Management Review Results," and 3.2, "Mechanical Systems," and Section C, "Identification of Aging Effects and Aging Management Review Summaries." The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the reactor and reactor coolant system (RCS) will be adequately managed so that the intended function(s) will be maintained in a manner that is consistent with the current licensing basis (CLB) during the period of extended operation as required by 10 CFR 54.21(a)(3). The environment, material, aging effects, and aging management program for each component in the reactor and reactor coolant systems are documented in Tables 3.2.1-1, 3.2.1-2, and 3.2.2-1 of the LRA. Section C.1 of the LRA contains the evaluation of aging effects requiring management review, and Section C.2 of the LRA contains the aging management reviews for each commodity group. A commodity group is defined as systems or components that were constructed using similar materials and are operating in similar environments.

External environments are defined in Sections 3.1.2.8, "Inside"; 3.1.2.9, "Outside"; and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. SCs that perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.2.2 Summary of Technical Information in the Application

The RCS consists of the fuel, nuclear boiler system, reactor assembly system, and reactor recirculation system. Each of these systems is described below.

Fuel

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

The external environment of the fuel is a cladding surrounded by water. The fuel cladding experiences the complete range of reactor coolant pressure and temperatures.

Additional information may be found in Section 4.2.1.2 of the Plant Hatch Unit 2 FSAR.

Nuclear Boiler System

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

The system contains the following major components:

- main steam lines (MSLs)
- safety relief valves (SRVs)
- main steam isolation valves (MSIVs)
- feedwater lines
- feedwater line check valves
- instrumentation and controls

Reactor Assembly System

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

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

Reactor Recirculation System (RRS)

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

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

More information about this system may be found in Section 4.3 of the Plant Hatch Unit 1 FSAR and Section 5.5.1 of the Plant Hatch Unit 2 FSAR.

3.2.2.1 Effects of Aging

The applicant identified the aging effects, component functions, environment, and materials for each component in the reactor assembly system, the nuclear boiler system, and the reactor recirculation system in Tables 3.2.1-1, 3.2.1-2, and 3.2.2-1 of the LRA, respectively.

Since fuel is subject to replacement within a specified time period, according to 10 CFR 54.21(a)(1)(ii), fuel does not require an integrated assessment.

The aging effects for the nuclear boiler system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness resulting from thermal aging of cast austenitic stainless steel valve bodies

The aging effects for the reactor assembly system are as follows:

- cracking due to stress corrosion and fatigue
- loss of fracture toughness resulting from neutron irradiation embrittlement of beltline materials

The aging effects for the reactor recirculation system are as follows:

- cracking
- loss of preload

- loss of material

- loss of fracture toughness resulting from thermal aging of cast austenitic stainless steel pump casing and covers and valve bodies

Survey of Industry Experience

Industry experience was collected from resources such as NRC generic letters, bulletins and information notices; GE service information letters; INPO significant operating event reports; and topical information from various industry working groups. Plant-specific information was derived through plant walkdowns, interviews, and records searches. A list of generic communications considered by the applicant is provided in Section C.1.5 of the LRA.

Survey of Industry Experience for the Nuclear Boiler System

As a result of the review of the condition reporting database, the only age-related deficiency identified was a loss of material due to erosion corrosion of carbon steel components within the Class 1 boundary and exposed to reactor water. NRC Integrated Inspection Report 99-02 concluded that flow-accelerated corrosion (FAC) inspections were conducted and evaluated in accordance with procedures, and the applicant had implemented an effective program to maintain high-energy carbon steel piping systems within acceptable wall thickness limits.

Several instances of leaking Class 1 bolted closures were found during pressure testing conducted prior to drywell closure. These leaks were minor and, in the majority of cases, may be attributed to the thermal effects associated with cooldown of the Class 1 systems for outages. In all cases, these leaks were corrected in accordance with Plant Hatch's implementation of ASME Section XI in-service inspection (ISI) program. Activities performed in accordance with vendor service information letters also contribute to the overall reduction of these leaks. Operating experience with CRD flange bolts indicates numerous instances of pitting and crevice corrosion. These conditions were discovered during ISI program inspections. All fasteners demonstrating evidence of corrosion were replaced.

Several failures of piping components downstream of orifices or other pressure reduction devices within steam systems were noted. In all cases, the cause of the failure was attributed to erosion corrosion related to pressure fluctuations within the system. This experience validates the conclusion that erosion corrosion can occur in areas not identified by the FAC model. The FAC program and treated water systems piping inspections will specifically target these suspect areas for increased inspections in order to minimize future loss of component function. NRC Integrated Inspection Report 99-02 concluded that FAC inspections were conducted and evaluated in accordance with procedures, and the applicant had implemented an effective program to maintain high-energy carbon steel piping systems within acceptable wall thickness limits.

Survey of Industry Experience for the Reactor Assembly System

A review of the operating experience for both Hatch units indicates that there are no outstanding problems. Routine examinations as part of the ISI program and augmented in-vessel inspections, as well as normal maintenance and refueling activities, have not revealed any

unanticipated age-related issues for the reactor vessel. There was one instrument penetration that developed a leak attributed to intergranular stress corrosion cracking (IGSCC). The leak was detected as part of normal drywell outage activities and repaired. Corrosion was detected on the mating surface of the Unit 2 RPV head vent flange and repaired. Finally, during a routine maintenance activity, CRD flange bolts were found to have evidence of pitting. All CRD flange bolts were replaced and are inspected routinely upon disassembly.

The operating experience for the Hatch internals was reviewed. Over time, there have been several occurrences of cracking, all of which have been repaired or are currently being monitored in accordance with prescribed procedures and programs. Early in life, IGSCC was detected on the Unit 1 core spray sparger. It was repaired by installing a mechanical clamp. The sparger has been full-flow tested and the clamp examined afterwards with no evidence of degradation. Multiple indications have been detected over the years on the non-safety-related steam dryers. Some have been repaired, while others are monitored. Jet pump inspections have resulted in minor indications associated with set-screw gaps, diffuser-to-adapter welds, riser pipe welds, and tack welds. These are being monitored and reexamined in accordance with the provisions of the boiling water reactor vessel and internals program (BWRVIP). Crack-like indications were also detected in the core shrouds for both units. The applicant conservatively decided to make pre-emptive repairs to eliminate the concern of cracking in shroud circumferential welds. The repaired hardware and vertical welds are periodically examined as specified in the BWRVIP.

Survey of Industry Experience for the Reactor Recirculation System

While no significant failure trends were found within the prior 5 years, the RRS piping has experienced significant age-related degradation due to IGSCC of weld heat-affected zones. Specifically, the Unit 1 piping components have undergone extensive weld overlay repair, and the Unit 2 piping has been replaced with 316NG stainless steel. A primary contributor to these IGSCC failures is dissolved oxygen content in the reactor water. Prior to initiation of hydrogen injection, higher levels of dissolved oxygen produced by radiolysis within the core region created an oxidizing environment conducive to IGSCC. Implementation of hydrogen water chemistry has effectively arrested existing IGSCC-induced cracks, and has prevented new cracks from forming. Therefore, the current reactor water chemistry control in conjunction with other mitigative activities has proven effective in mitigating failures caused by IGSCC.

3.2.2.2 Aging Management Programs

The applicant identified the aging management programs for components in the reactor assembly system, the nuclear boiler system, and the reactor recirculation system in Tables 3.2.1-1, 3.2.1-2 and 3.2.2-1, respectively, of the LRA.

The aging management programs for the nuclear boiler system are as follows:

- torque program
- protective coatings program
- inservice inspection program
- reactor water chemistry program
- component cyclic or transient limit program

- treated water systems piping inspections program
- galvanic susceptibility inspections program
- flow-accelerated corrosion program
- demineralized water and condensate storage tank chemistry control program
- suppression pool chemistry control program
- torus submerged components inspection program
- gas system components inspections program
- passive components inspection program

The aging management programs for the reactor assembly system are as follows:

- boiling water reactor vessel internals program
- reactor pressure vessel monitoring program
- reactor water chemistry control program
- component cyclic or thermal transient limit program
- inservice inspection program

The aging management programs for the RRS are as follows:

- reactor water chemistry control program
- component cyclic or transient limit program
- inservice inspection program
- torque program
- treated water systems piping inspection program

The applicant concluded that these programs would manage aging effects in such a way that the intended function of the components would be maintained consistent with the CLB, under all design loading conditions during the period of extended operation.

3.2.3 Staff Evaluation

The applicant described its AMR for the reactor assembly system, nuclear boiler system and RRS in Section 3.2 and Section C of the LRA . The NRC staff reviewed these sections to determine whether the applicant has identified the aging effects for components in these systems and demonstrated that the effects of aging on the components systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). Each commodity group associated with these components was reviewed by the staff to determine the applicability of the aging effects to the system and its components. The staff reviewed each aging management program associated with these components to determine whether the effects of aging will be adequately managed by the program.

3.2.3.1 Effects of Aging

The aging effects for the reactor assembly system, nuclear boiler system, and RRS identified by the applicant are discussed in Section 3.2.2.1 of this SER.

3.2.3.1.1 Effects of Aging on the Reactor Assembly System

The aging effects for the reactor assembly system are as follows:

- cracking due to stress corrosion and fatigue
- loss of fracture toughness resulting from neutron irradiation embrittlement of beltline materials

<u>Cracking</u>

All components in the reactor assembly system, except for the shell and closure head, are subject to cracking. Cracking of the vessel shell and closure head due to fatigue and stress corrosion cracking (SCC) was determined not to be an aging effect requiring management by BWRVIP-74, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines." The applicable fatigue usage factors for the vessel are very low in comparison to other RPV locations. As for SCC of the low-alloy steel vessel shells, BWRVIP-05, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," and BWRVIP-60, "Evaluation of Crack Growth in BWR Low Alloy Steel RPV Internals," indicate that even if cracks were to emanate from the vessel cladding, they are not expected to propagate into the low-alloy steel of the reactor vessel. BWRVIP-05 and BWRVIP-60 have been reviewed and approved by the staff. The vessel attachment welds are inspected in accordance with the staff approved BWRVIP-48, "Vessel ID Attachment weld Inspection and Flaw Evaluation Guidelines," which adequately manages age-related degradation for cracking at these locations.

<u>Loss of Material</u>

The closure studs in the reactor assembly system are not identified as being subject to loss of material or loss of preload. In response to RAI 3.2.3.1-1, the applicant indicated that closure studs are evaluated in BWRVIP-74. BWRVIP-74 does not identify closure studs as being subject to loss of material or loss of preload. The staff agrees with this conclusion because the closure studs are examined during each refueling outage and loss of material or loss of preload has not been identified as an aging effect in the boiling water reactor (BWR) environment.

Although components in the reactor assembly system are in a reactor water environment, the commodity groups in the reactor assembly system are not subject to loss of material. In response to RAI 3.2.3.1-1, the applicant indicates that evaluations performed with regard to vessel components utilized BWRVIP reports that are based on extensive research, testing, and industry experience. Based on the extensive research, testing, and industry experience, the applicant indicated that loss of material is not an aging effect for components in the reactor assembly system. Based on the applicant's response to this RAI, the staff agrees that commodity groups in the reactor assembly system are not susceptible to loss of material.

<u>Void Swelling</u>

According to EPRI technical report TR-107521, void swelling is defined as a gradual increase in dimension of an austenitic stainless steel part as a result of helium bubble nucleation and growth from nuclear transmutation reactions of nickel and boron in the material. EPRI TR-107521 cites sources with conflicting results on predicting the extent of possible void swelling for light-water

reactor conditions. One source predicts swelling as great as 14% for PWR baffle-former assemblies over a 40-year plant lifetime, whereas results from another source indicate that swelling would be less than 3% for the most highly irradiated sections of the internals at 60 years. The issue of concern to the staff is the impact of change of dimension due to void swelling on the ability of the reactor vessel internals to perform their intended functions. Swelling of the reactor vessel internals could potentially impact the ability to insert control element assemblies and to maintain proper coolant flow distribution characteristics.

In response to RAI 3.2.3.1-2, the applicant indicated that BWR reactor vessel internals are a greater distance from the fuel than PWR reactor vessel internals and are expected to experience less neutron fluence. In addition, the lowest temperature for which this phenomenon is conjectured to occur is 572 °F, which is a temperature higher than the internals that either Plant Hatch unit will experience. Further, the BWRVIP for BWR internals addressed the key aspects of the internals components and provided inspection criteria, where appropriate, to manage aging. The BWRVIPs that are being implemented at Plant Hatch are adequate to address aging of the internals. Since BWR reactor vessel internals have relatively low neutron fluence and the applicant will perform inspections in accordance with the staff-approved BWRVIP reactor vessel internals programs, the staff concludes that void swelling is not a concern for Plant Hatch.

Neutron and Thermal Embrittlement

CASS components in the reactor assembly system may be subject to loss of fracture toughness due to the synergistic effects of thermal and neutron embrittlement. CASS components are susceptible to thermal embrittlement if they operate at temperatures greater than 550 °F. Appendix H to 10 CFR Part 50 indicates that neutron irradiation embrittlement becomes significant at neutron fluences greater than 10^{17} n/cm^{2} (E>1Mev).

Table 2.3.1-1 of the LRA indicates that jet pump assemblies and fuel supports contain CASS components and are within the scope of license renewal. The Plant Hatch fuel supports support the weight of the fuel assemblies and distribute core flow into the fuel assemblies. Table 2.3.1-1 indicates that the CASS fuel supports have no aging effects requiring management. However due to the proximity to the core, the CASS fuel supports are likely to be susceptible to the synergistic effects of thermal and neutron embrittlement.

In response to RAI 3.2.3.2-1, the applicant indicated that portions of the jet pump assemblies may experience fluence greater than 10^{17} n/cm^{2} , but will not experience temperatures exceeding 550 °F. Therefore, jet pump assemblies fabricated from CASS will not be susceptible to thermal embrittlement; but may be susceptible to neutron embrittlement. The applicant indicates that aging management of CASS components is provided by the BWRVIP.

The BWRVIP for the jet pump assembly components is described in EPRI TR-108728, "BWRVIP BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (BWRVIP-41)." The staff-approved BWRVIP-41 does not recommend an inspection of CASS jet pump assembly components because CASS components are considered not susceptible to IGSCC and the neutron fluence in the annulus region is not large enough to cause irradiation embrittlement. However, BWRVIP-41 does not contain any data to indicate the threshold for neutron embrittlement of CASS and does not identify the neutron fluence of the CASS jet pump assembly components. Because BWRVIP-41 does not provide data to support its conclusion

that inspection of CASS components is not needed, the staff cannot conclude that the loss of fracture toughness resulting from irradiation embrittlement and cracking is not a plausible aging effect requiring aging management. The staff notes that irradiation embrittlement of CASS components becomes a concern only if cracks are present in the components. Therefore, if the applicant can show that cracks do not occur in the CASS components, then the staff can conclude that loss of fracture toughness resulting from neutron irradiation embrittlement will not be a significant aging effect.

Industry-wide experience shows that significant cracking has not been observed in CASS jet pump assembly components. To confirm that CASS components are not susceptible to cracking, the applicant should propose an AMP (one-time inspection) for the CASS jet pump assembly components and fuel supports, which will be conducted prior to beginning the extended operating period. The BWRVIP and the NRC's Office of Regulatory Research (RES) is engaged in a joint confirmatory research program to determine the effects of high levels of neutron fluence on BWR internals, including associated age-related degradation, to confirm if CASS components are susceptible to cracking as a result of neutron embrittlement. The results of this program should be used to evaluate the need for the additional one-time inspection of the CASS jet pump assemblies and fuel supports, and to modify the inspection scope and/or frequency, as needed. The applicant should address the 10 AMP attributes in its description of the inspection, including any corrective actions to be taken (including repair and replacement) if cracking is discovered. This is Open Item 3.2.3.1.1-1.

3.2.3.1.2 Effects of Aging on the Nuclear Boiler System

The aging effects for the nuclear boiler system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness resulting from thermal aging of cast austenitic stainless steel valve bodies

All components, except for bolting in the nuclear boiler system, are subject to cracking. In response to RAI 3.2.3.1-1, the applicant indicated that SCC and fatigue were considered potential mechanisms contributing to cracking of bolting in the nuclear boiler system. However, after considering the causes of SCC and the ASME Code fatigue analysis for bolting, the applicant concluded that these potential mechanisms did not result in aging effects that require aging management. A summary of the applicant's evaluation is provided below.

Stress Corrosion Cracking of Bolting

- Stress corrosion crack initiation and propagation requires that the affected fastener be subjected to water or steam environments containing various contaminants. Significant wetting of fasteners due to mechanical joint leakage is not considered a normal operating condition.

- A common factor in fastener SCC failures involves the usage of lubricants containing MoS_2, or other lubricants that form contaminants that promote SCC when in contact with reactor water. At Plant Hatch, procedural controls prevent the use of these lubricants in safety-related fasteners, thereby further minimizing the potential for SCC to occur.

- The vast majority of bolting failures due to SCC have occurred at PWRs. Boric acid environments are the primary contributors to these SCC failures. Since Plant Hatch is a BWR, bolting does not experience conditions conducive to SCC initiation and propagation.

- Plant Hatch has implemented procedural processes to minimize the potential for excessive applied stresses due to improper preload.

Cracking Resulting from Fatigue of Bolting

Cracking due to fatigue is not considered by the applicant to be an aging effect requiring management for nuclear boiler system fasteners, since the effects of fatigue are generally seen in conjunction with SCC for high-strength fasteners. In addition, pressure bolting for flanged connections in Class 1 systems is designed to meet the requirements of ASME Section III, Paragraph NB-3232.3, which requires that an analysis be performed to evaluate the effect of fatigue (both thermal and vibration induced) on the component.

On the basis of the information provided by the applicant supporting its conclusion that bolting in the nuclear boiler system is not subject to SCC or cracking due to fatigue, the staff concludes that the applicant has not provided sufficient information for the staff to conclude that bolting in the nuclear boiler system is not subject to cracking. The staff is concerned that bolting that is heat treated to a high hardness condition and exposed to a humid environment within containment could be susceptible to SCC. NUREG-1339, “Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants,” indicates that the bolts’ actual yield stress should be less than 150 ksi to preclude SCC. The applicant should indicate whether all bolting has been heat treated to a yield stress of less than 150 ksi or its Rockwell hardness equivalent. Resolution of this issue is part of Open Item 3.1.11-1, and is discussed in Section 3.1.11 of this SER. All bolting that has been heat treated to a high hardness condition should be considered susceptible to SCC, and should have an aging management program to detect this type of cracking.

Loss of Material

Class 1 bolting in the nuclear boiler system is identified as not being subject to loss of material. However, all fasteners within the Class 1 boundary are fabricated from low-alloy steels such as SA540, Grade B23 or SA193, Grade B7. The addition of alloy elements prevents general

corrosion due to atmospheric contact. Since the normal environment does not include significant wetting, loss of material due to corrosion was not an aging effect requiring management for these fasteners.

All non-stainless steel, non-Class 1 fasteners were evaluated together as a commodity. Many fastener applications at Plant Hatch utilize carbon steel fasteners. The applicant concluded that these fasteners could be potentially susceptible to loss of material. This conclusion was conservatively applied to all non-Class 1 carbon and low-alloy steel fasteners.

The staff agrees that the applicant has identified all components in the nuclear boiler system that are susceptible to loss of material.

3.2.3.1.3 Effects of Aging on the Reactor Recirculation System

The aging effects for the reactor recirculation system are as follows:

- cracking
- loss of preload
- loss of material
- loss of fracture toughness resulting from thermal aging of cast austenitic stainless steel pump casing and covers and valve bodies

On the basis of the review of the information provided in the LRA, the staff concludes that the applicant has adequately identified the plausible aging effects associated with components in the RRS.

The staff concludes that all applicable aging effects have been identified for the reactor assembly system, nuclear boiler system, and RRS, consistent with published literature and industry experience.

3.2.3.2 Aging Management Programs

The aging management programs for the reactor assembly system, nuclear boiler system and RRS are identified in Section 3.2.2.2 of this SER. The aging management programs are reviewed by the staff in the following sections of the SER:

- reactor water chemistry program, Section 3.1.1

- demineralized water and condensate storage tank chemistry control program, Section 3.1.6

- suppression pool chemistry control program, Section 3.1.7

- inservice inspection program, Section 3.1.9

- torque activities program, Section 3.1.11

- component cyclic or transient limit program, Section 3.1.12

- boiling water reactor vessel internals program, Section 3.1.15
- reactor pressure vessel monitoring program, Section 3.1.17
- flow accelerated corrosion program, Section 3.1.19
- protective coatings program, Section 3.1.20
- galvanic susceptibility inspections program, Section 3.1.23
- treated water systems piping inspections program, Section 3.1.24
- gas system components inspections program Section 3.1.25
- passive components inspection program, Section 3.1.27
- torus submerged components inspection program, Section 3.1.29

3.2.3.2.1 Aging Management Programs for Cast Austenitic Stainless Steel (CASS) Components

This section provides the staff evaluation of the applicant's management of CASS components in the RCS systems.

<u>CASS Components within the Nuclear Boiler System and Reactor Recirculation System</u>

The industry position on CASS is described in the Electric Power Research Institute (EPRI) topical report (TR)-106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems," dated September 1997. This report provides a methodology for determining whether CASS components are potentially susceptible to significant thermal embrittlement that could lead to loss of structural integrity if cracks were in the component. The staff's evaluation of EPRI TR-106092 is contained in a letter from C.I. Grimes (NRC) to D.J. Walters (NEI), dated May 19, 2000. The staff's evaluation indicates that the definition of components in EPRI TR-106092 that are potentially susceptible to significant thermal embrittlement are acceptable, with the exception that: (a) static casting with high molybdenum and greater than 14% ferrite content would be considered susceptible to significant thermal embrittlement; (b) components with Niobuim would be considered susceptible to significant thermal embrittlement; (c) components with greater than 25% ferrite would be considered susceptible to significant thermal embrittlement; (d) the calculated ferrite must be determined using Hull's equivalent factors or a methodology producing an equivalent level of accuracy (6% deviation between measured and calculated values); and (e) the flaw evaluation procedures in IWB-3640 are applicable to thermally aged CASS with ferrite levels up to 25%. Evaluation of CASS components with ferrite levels greater than 25% should use fracture toughness data representative of the higher ferrite contents.

The ASME Code ISI for valve bodies equal to or greater than 4 inches nominal pipe size (NPS) and for pump casings requires a volumetric examination of the welds and a visual (VT-3) of the

inside surfaces. These examinations should be able to detect cracks in these valve bodies and pump casings before they reach a critical size, and these CASS components need only be examined to ASME Code ISI requirements.

The ASME Code ISI program for valve bodies less than 4 inches NPS requires an outside surface examination, but does not require internal visual or volumetric examination. However, a staff evaluation of CASS valve bodies less than 4 inches NPS indicates that (1) there have been no reported instances of valve body cracking in these small valves, and (2) aged CASS valve bodies, even with extremely low fracture toughness, can withstand very large through-wall cracks. Therefore, valve bodies need only be examined to ASME Code ISI program requirements.

The CASS components outside the reactor vessel are pump casings, valve bodies, and the main steam flow restriction venturi elements. The venturi elements have been determined to not be susceptible to thermal embrittlement based on the grade of CASS and the operating temperature. With the exception of the venturi elements, the applicant will manage cracking and any associated impact of thermal embrittlement should it occur in these components. The aging management will be accomplished through the ISI program, which includes the inspection requirements of Section XI. This meets the position identified in the letter from C.I. Grimes to D.J. Walters dated May 19, 2000. Since the venturi elements are not susceptible to thermal embrittlement and pump casings and valve bodies are inspected to ASME Code ISI requirements, the staff concludes that these components have adequate aging management programs

<u>CASS Components within the Reactor Assembly System</u>

The effect of neutron and thermal embrittlement on CASS components within the reactor assembly system is discussed in Section 3.2.3.1.1 of this SER.

3.2.3.2.2 Aging Management Programs for Vessel Flange Leak Detection (VFLD) Line

The staff was concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants, and cause cracking in the VFLD line. The applicant indicated that the Plant Hatch Unit 1 VFLD line is subject to the AMP for Class 1 stainless steel piping in the nuclear boiler system. Cracking is identified as an aging effect for this commodity group. The ASME Code requires that the welds in Class 1 piping of the size of the VFLD line be inspected using a surface examination, and the pressure boundary to be VT-2-inspected following the system leakage test after each refueling outage.

In the LRA, the applicant indicated that the Plant Hatch Unit 2 VFLD line is stainless steel and contains portions that are classified as Class 1 piping and non-Class 1 piping. The Class 1 piping would be examined to ASME Code Section XI requirements. The non-Class 1 stainless steel piping in the nuclear boiler system will be examined in accordance with the treated water systems piping inspections (TWSPI). The TWSPI program provides for a one-time visual inspection of the sample set using the best available examination method. Inspections may utilize an examination similar to that described for VT-1 in the ASME Code.

The inspections implemented as part of the ISI program for Class 1 piping and the inspections implemented as part of the TWSPI program for non-Class 1 piping should be able to detect cracking in the VFLD line. On the basis of the information provided by the applicant and summarized above, the staff concludes that the applicant can adequately manage cracking associated with the VFLD.

3.2.3.2.3 Aging Management Programs for ASME Code Class 1 Small-Bore Piping

NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," identified cracking in an unisolable section of emergency core cooling system piping connected to the reactor coolant system. The cause of the cracking was high cycle thermal fatigue created by relatively cold water leaking through a closed valve. In addition, cracks in piping have also been attributed to vibratory fatigue and stress corrosion aging mechanisms.

In response to RAI 3.2.3.2-8, the applicant indicated that the following systems contain ASME Code Class 1 small-bore piping that could be subject to cracking from thermal fatigue or stress corrosion aging mechanisms:

B21 - nuclear boiler system
B31 - RRS
C41 - SLCS
E11 - RHR system
E21 - CS system
E41 - HPCI system
E51 - RCIC system
G31 - RWCU system

Since carbon steel and stainless steel components in these systems are subject to changes in temperature, cracking due to thermal fatigue is an aging effect requiring management. For pipe sizes above 1 inch, the AMP credited for managing aging of these components due to thermal fatigue is the component cyclic or transient limit program. Class 1 piping that is 1 inch and smaller was analyzed using ASME Class 2 methods. For such piping, cracking due to thermal fatigue is addressed as a TLAA in LRA Section 4.2.3, which demonstrates that the analyses remain valid throughout the extended period of operation. Cracking due to vibratory fatigue is not considered an aging effect requiring management since failure of these components due to vibration has been precluded by design.

As described in Section C.1.2.1.2 of the LRA, for SCC to occur in components of the above systems, each of the following three conditions must simultaneously exist:

1. The components must contain susceptible materials (in this case, stainless steel or nickel based alloys).

2. The components must be subject to residual tensile stresses of sufficient magnitude.

3. The components must be subject to a potentially corrosive environment.

All three conditions exist simultaneously in the above systems, so cracking due to IGSCC is an aging effect requiring management.

For these systems, the applicant defines the corrosive environment as high-temperature water where the electrochemical corrosion potential of alloys exposed to the coolant is increased due to the presence of radiolytically produced dissolved oxygen and hydrogen peroxide. Without the appropriate reactor water chemistry controls, this corrosive environment could exist. Therefore, to manage SCC in the above systems, the applicant has credited reactor water chemistry control, coupled with either the ISI program (for 2-inch and larger piping in these systems) or the TWSPI (for piping in these systems that is not included in the ISI program).

The staff is concerned that the low-cycle fatigue and the unanticipated high-cycle thermal fatigue resulting from thermal stratification or turbulent penetration and SCC could result in cracking of small bore piping (piping with full-penetration welds). The ASME Code Class 1 inspection requirements for small-bore piping include a surface examination, but not a volumetric examination. In order to detect cracking resulting from these aging effects, a volumetric examination is required. Since the proposed program does not include a volumetric examination, it may not be capable of detecting the aging effects. Therefore, the applicant should supplement the existing programs with volumetric examination of the limiting locations in small-bore piping systems (excluding socket welds) or provide justification why such examination is not necessary. This is Open Item 3.2.3.2.3-1.

3.2.4 Conclusion

The staff has reviewed the information in Sections 3.0 and 3.2, and Section C of the LRA. On the basis of this review, and pending satisfactory resolution of Open Items 3.1.1-1, 3.1.11-1, 3.1.17-1, 3.2.3.1.1-1, and 3.2.3.2.3-1, the staff concludes that the applicant has demonstrated that the aging effects associated with the reactor and RCS 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.

3.3 Engineered Safety Features

3.3.1 Introduction

The applicant described its AMR for the engineered safety features (ESF) systems for license renewal in Section 3.2.3, “Engineered Safety Features (ESF) Systems,” of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ESF systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2 Summary of Technical Information in the Application

The applicant provided an AMR of eight ESF systems that are considered to be within scope of the license renewal rule. A brief description of each system is provided below.

Core Spray System

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

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

High-Pressure Coolant Injection System

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

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

Post-LOCA Hydrogen Recombiner System (Unit 2)

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

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

Primary Containment Purge and Inerting System

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

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

Reactor Core Isolation Cooling System

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

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

Residual Heat Removal System

The RHR system is composed of several components and subsystems that are required to maintain the following functions:

- Restore and maintain reactor vessel water level after a LOCA.
- Limit temperature and pressure inside the containment after a LOCA.
- Remove heat from the suppression pool water.

- Remove decay and residual heat from the reactor core to achieve and maintain a cold shutdown condition.

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

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

Standby Gas Treatment System

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

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

Standby Liquid Control System

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

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

3.3.2.1 Effects of Aging and Aging Management Programs

The applicant presented the aging effects and aging management programs for the subsystems in the ESF system in Sections C.1 and C.2 of the LRA. The applicable internal environments for

the components in the ESF systems are: reactor water, demineralized water, suppression pool, borated water, river water, dry compressed gas, humid or wetted gases, and inside environments. External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete.

Cracking due to thermal fatigue is an applicable aging effect for several ESF components. The applicant states that all non-Class 1 components are enveloped by a time limited aging analysis (TLAA) that adequately addresses this aging effect without regard to the individual component or system conditions. This analysis is presented in Section 4.2.3 of the application. The staff's evaluation of this analysis is presented in 4.2 of this SER.

<u>Reactor Water Environment</u>

Section C.2.2.1 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The reactor water is used in the power cycle, and is demineralized and maintained with low levels of impurities (halogens and sulfates) and minimal dissolved oxygen concentrations. Reactor water quality is maintained in accordance with the reactor water chemistry control program, which implements the guidance of the BWR water chemistry guidelines promulgated by the Electric Power Research Institute (EPRI).

Based on Tables 3.2.3-4 and 3.2.3-5 of the LRA, the HPCI system and the RCIC system contain piping, restricting orifices, valve bodies, and steam traps manufactured from these materials, and are exposed to the reactor water environment under normal conditions.

The aging effects of carbon steel components exposed to the reactor water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- reactor water chemistry control
- flow accelerated corrosion (FAC) program
- treated water systems piping inspections
- galvanic susceptibility inspections

The aging effects of stainless steel components exposed to the reactor water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- reactor water chemistry control
- treated water systems piping inspections

<u>Demineralized Water Environment</u>

Section C.2.2.2 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The demineralized water is

processed on site and stored in demineralized water storage tanks and condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels, but dissolved oxygen concentrations are neither controlled nor monitored.

Based on Tables 3.2.3-4 and 3.2.3-5 of the LRA, the HPCI system and the RCIC system contain piping, pump casings, restricting orifices, valve bodies, and thermowells manufactured from these materials and exposed to the demineralized water environment under normal conditions.

The aging effects of carbon steel components exposed to the demineralized water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections

The aging effects of stainless steel components exposed to the demineralized water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry Control
- treated water systems piping inspections

<u>Suppression Pool Environment</u>

Section C.2.2.3 of the LRA discusses the aging management of various materials in this commodity group, including carbon steel, cast austenitic stainless steel, and stainless steel. The suppression pool water is contained within the torus, and consists of demineralized water supplied from sources such as the condensate storage tanks. Detrimental impurities and conductivity are maintained at low levels, although allowable levels are well above those acceptable. Dissolved oxygen concentrations are neither controlled nor monitored.

Based on Tables 3.2.3-2, 3.2.3-3, 3.2.3-4, 3.2.3-5, and 3.2.3-7 of the LRA, the RHR system, the CS system, the HPCI system, the RCIC system, and the primary containment purge and inerting system contain conductivity elements, piping, pump casings, restricting orifices, strainers, thermowells, and valve bodies that are manufactured from these materials and are exposed to the suppression pool water environment under normal conditions.

The aging effects of carbon steel components exposed to the suppression pool water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- suppression pool chemistry control

- protective coatings program (external surfaces of submerged components in suppression pool)

- torus submerged components inspection program

- treated water systems piping inspections

- galvanic susceptibility inspections

The aging effects of stainless steel and cast austenitic stainless steel components exposed to the suppression pool water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- suppression pool chemistry control
- torus submerged components inspection program
- treated water systems piping inspections

<u>Borated Water Environment</u>

Section C.2.2.4 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The borated water is contained within the SLCS and consists of demineralized water supplied from the demineralized water storage tank, with approximately 10% by weight sodium pentaborate added. Concentrations of anion species are quite low, thereby minimizing significant corrosion within the system. The SLCS storage tank is not regularly monitored for detrimental impurities.

Based on Table 3.2.3-1 of the LRA, the SLCS contains piping, pump accumulators, pump casings, tanks, thermowells, and valve bodies that are manufactured from these materials and are exposed to the borated water environment under normal conditions.

The aging effects of carbon steel components exposed to the borated water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- protective coatings program
- demineralized water and condensate storage tank chemistry control

The aging effects of stainless steel components exposed to the borated water environment are loss of material and cracking. The management of these aging effects is achieved through the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections

<u>River (Raw) Water Environment</u>

Section C.2.2.6 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, stainless steel, cast austenitic stainless steel, and copper alloys. River water is supplied from the Altamaha River via a roughly screened intake structure. It is assumed that some debris, silt, and macroorganisms may be introduced into the plant service water (PSW) and RHR service water (RHRSW) systems.

Based on Table 3.2.3-2 of the LRA, the RHR system contains piping, pump discharge heads, pump casings, restricting orifices, strainer bodies, tubing, and valve bodies that are manufactured from these materials and exposed to the river water environment under normal conditions.

The aging effects of carbon steel components exposed to the river water environment are loss of material, cracking, and flow blockage. The management of these aging effects is achieved through the following aging management programs:

- PSW and RHRSW chemistry control
- PSW and RHRSW inspection program
- structural monitoring program
- galvanic susceptibility inspections

The aging effects of stainless steel, cast austenitic stainless steel, and copper alloy components exposed to the river water environment are loss of material, cracking, and flow blockage. The management of these aging effects is achieved through the following aging management programs:

- PSW and RHRSW chemistry control
- PSW and RHRSW inspection program
- structural monitoring program

Dry Compressed Gas Environment

Section C.2.2.8 of the LRA discusses the aging management of various materials in this commodity group, including carbon steel and stainless steel. The dried gas environment includes any process gas including, but not limited to air, nitrogen (including cyrogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or is filtered and dessicated to remove moisture prior to entering the system.

Based on Tables 3.2.3-4 and 3.2.3-7 of the LRA, the HPCI system, and the primary containment purge and inerting system contain flexible connectors, piping, pressure buildup coils, rupture discs, storage tanks, valve bodies, and vaporizers that are manufactured from these materials and exposed to the dry compressed gas environment under normal conditions.

The aging effect of all the above carbon steel and stainless steel components exposed to the dry compressed gas environment is cracking. The management of this aging effect is achieved through the TLAA on thermal fatigue, discussed in Section 4.2 of the LRA and reviewed by the staff in Section 4.2 of this SER.

Humid and Wetted Gas Environment

Section C.2.2.9 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, gray cast iron, stainless steel, copper alloy, galvanized carbon steel, and aluminum. The non-dried gases included in the humid and wetted environment is air (nitrogen in the case of the inerted drywell) containing humidity or significant moisture. These gases are assumed to contain sufficient moisture and oxygen to enable pooling of the liquid at low or especially cool locations and promote corrosion.

Based on Tables 3.2.3-2, 3.2.3-4, 3.2.3-5, 3.2.3-6, 3.2.3-7, and 3.2.3-8 of the LRA, the RHR system, the HPCI system, the RCIC system, the SGTS, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only) contain piping, turbine casing, restricting orifice, valve bodies, steam trap, strainer-steam exhaust, filter housing, rupture disc, thermowell, flex hose, and nitrogen tank jacket that are manufactured from these materials and exposed to the humid and wetted gas environment under normal conditions.

The aging effect of carbon steel and gray cast iron components exposed to the wetted gas environment is loss of material. The management of this aging effect is achieved through the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The aging effect of stainless steel, copper, and copper alloy components exposed to the wetted gas environment is loss of material. The management of this aging effect is achieved through the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The other aging effect of carbon steel and stainless steel components exposed to the wetted gas environment is cracking. The management of this aging effect is achieved through the TLAA on thermal fatigue, discussed in Section 4.2 of the LRA and reviewed by the staff in Section 4.2 of this SER.

Inside Environment

Section C.2.4.1 of the LRA, discusses the aging management of various materials in this commodity group, including carbon steel, cast iron, stainless steel, copper alloy, galvanized carbon steel, and cast iron. The normal inside environment is an environment where minimal wetting and wet/dry cycling is expected to occur.

Based on Tables 3.2.3-2, 3.2.3-4, and 3.2.3-5 of the LRA, the RHR system, the HPCI system, and the RCIC system contain pump sub bases and pump base plates that are manufactured from carbon steel and exposed to the inside environment.

The aging effect of the carbon steel components exposed to the inside environment is loss of material. The management of this aging effect is achieved through the protective coatings aging management program.

Bolting Materials

Section C.2.2.10 of the LRA, discusses only the carbon steel and stainless steel bolting pertaining to piping connections that are exposed to inside and outside environments.

Based on Tables 3.2.3-1 through 3.2.3-5, 3.2.3-7, and 3.2.3-8 of the LRA, all ESF systems, except the SGTS, contain these bolts which are subject to an AMR.

The aging effects of carbon steel bolts exposed to an inside or outside environment are loss of material and loss of preload. The management of these aging effects is achieved through the following aging management programs:

- torque activities
- protective coatings program

The aging effect of stainless steel bolts exposed to an inside or outside environment is loss of preload. The management of this aging effect is achieved through the torque activities program.

<u>Residual Heat Removal Heat Exchangers</u>

Section C.2.2.11 of the LRA discusses the residual heat removal system heat exchangers, which are fabricated from several different materials and are exposed to multiple fluid environments.

Based on Table 3.2.3-2 of the LRA, the RHR heat exchangers contain several components that are subject to an AMR, including stainless steel heat exchanger tubes; carbon steel shell, shell nozzles, and shell internals; carbon steel channel assembly; carbon steel tube sheet with stainless steel cladding on raw water surfaces only; and stainless steel impingement plates.

The aging effects associated with these components are cracking, loss of material, and loss of heat exchanger performance. These aging effects are managed through the following programs:

- RHR heat exchanger augmented inspection and testing program
- Inservice inspection (ISI) program
- suppression pool chemistry control
- plant service water and RHR service water chemistry control
- structural monitoring program

3.3.3 Staff Evaluation

The applicant described its AMR of the SLCS, RHR system, CS system, HPCI system, RCIC system, SGTS, primary containment purge and inerting system, and post-LOCA hydrogen recombiners system (Unit 2 only), collectively called the ESF systems, in Section 3.2.3 and Sections A, B, and C of the LRA. In response to the staff's concerns regarding the aging management programs, the applicant provided Section B, "Response to Requests for Additional Information Related to Aging Management Programs Dated July 14, 2000 and July 28, 2000." The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the ESF systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

The staff's evaluation of the applicable aging effects for each ESF system and the aging management programs is presented in a manner similar to that provided in the LRA. The aging effects are discussed based on the environment, with a list of systems in which the environment is found. The aging management programs credited with managing these aging effects are also discussed. The aging effects for ESF components and the credited aging management programs discussed below are based on the stated internal environment, unless otherwise noted. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2 through 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.3.3.1 Aging Effects

Reactor Water Environment

The applicant lists carbon steel and stainless steel components exposed to the reactor water environment in the HPCI system and the RCIC system. The aging effects of carbon steel components exposed to the reactor water environment are loss of material due to general corrosion, galvanic corrosion, microbiologically influenced corrosion (MIC), crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the reactor water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to stress corrosion cracking (SCC), intergranular attack (IGA), and thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a reactor water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Demineralized Water Environment

The applicant lists carbon steel and stainless steel components that are exposed to the demineralized water environment in the HPCI system and the RCIC system. The aging effects of carbon steel components exposed to the demineralized water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the demineralized water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a demineralized water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Suppression Pool Environment

The applicant lists carbon steel, stainless steel, and cast austenitic stainless steel components exposed to the suppression pool environment in the RHR system, the CS system, the HPCI system, the RCIC system, and the primary containment purge and inerting system. The aging effects of carbon steel components exposed to the suppression pool water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, pitting, and erosion corrosion; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the suppression pool water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a suppression pool environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Borated Water Environment

The applicant lists carbon steel and stainless steel components exposed to the borated water environment in the SLCS. The aging effects of carbon steel components exposed to the borated water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice

corrosion, and pitting; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the borated water environment are loss of material due to crevice corrosion, pitting, and MIC; and cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a borated water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

River Water Environment

The applicant lists carbon steel, stainless steel, stainless steel-clad carbon steel, cast austenitic stainless steel, and copper alloy components exposed to river water in the RHR system. The aging effects of carbon steel components exposed to the river water environment are loss of material due to general corrosion, galvanic corrosion, MIC, crevice corrosion, fouling, and pitting; cracking due to thermal fatigue; and flow blockage due to fouling. The aging effects of stainless steel components exposed to the river water environment are loss of material due to crevice corrosion, pitting, MIC, and fouling; cracking due to thermal fatigue; and flow blockage due to fouling. The aging effects of copper alloy components exposed to the river water environment are loss of material due to selective leaching, galvanic corrosion, MIC, fouling and erosion corrosion; cracking due to thermal fatigue; and flow blockage due to fouling.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a river water environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Dry Compressed Gas Environment

The applicant lists carbon steel and stainless steel components exposed to the dry compressed gas environment in the HPCI system and the primary containment purge and inerting system. The aging effect of carbon steel and stainless steel components exposed to the dry compressed gas environment is cracking due to thermal fatigue.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a dry compressed gas environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Humid and Wetted Gas Environment

The applicant lists carbon steel, cast iron, stainless steel, copper alloy, and galvanized carbon steel components exposed to the nondried (wetted) gases in the RHR system, the HPCI system, the RCIC system, the SGTS, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only). The aging effects for carbon steel components exposed to the wetted gas environment are loss of material due to general corrosion, selective leaching, pitting, crevice corrosion, galvanic corrosion, and MIC; and cracking due to thermal fatigue. The aging effects of stainless steel components exposed to the wetted gas environment are loss of material due to pitting, crevice corrosion, and MIC; and cracking due to thermal fatigue, SCC, and IGA.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in a humid and wetted gas environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Inside Environment

The applicant lists carbon steel components exposed to a normal inside environment in the RHR system, the HPCI system, and the RCIC system. The aging effect of carbon steel components exposed to the inside environment is loss of material due to general corrosion in areas where the external surface is less than 200°F.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on materials in an inside environment, the staff concludes that the applicant has adequately identified the applicable aging effects.

Bolting Materials

The applicant lists carbon steel and stainless steel bolting associated with piping connections that are exposed to inside and outside environments at Plant Hatch. These components are found in the SLCS, the RHR system, the CS system, the HPCI system, the RCIC system, the primary containment purge and inerting system, and the post-LOCA hydrogen recombiner system (Unit 2 only). The aging effects of carbon steel bolts exposed to an inside or outside environment are loss of material due to general corrosion in the inside environment, and general corrosion, MIC, crevice corrosion, and pitting in the outside environment; and loss of preload due to embedment, gasket creep, thermal effects, and self-loosening. The aging effect of stainless steel bolts exposed to an inside or outside environment is loss of preload due to embedment, gasket creep, thermal effects, and self-loosening.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on bolting materials in various environments, the staff concludes that the applicant has adequately identified the applicable aging effects.

Residual Heat Removal Heat Exchangers

The applicant lists different components fabricated from several different materials that are exposed to multiple fluid environments. The aging effects associated with these components are cracking due to SCC and IGA of stainless steel components and vibration-induced fatigue; loss of material due to general corrosion, galvanic corrosion, crevice corrosion, pitting, MIC, and fouling; and loss of heat exchanger performance due to corrosion product buildup, silting, and macroorganism intrusion.

On the basis of the staff's evaluation of the information provided in the LRA with regard to aging effects on RHR heat exchanger materials in various environments, the staff concludes that the applicant has adequately identified the applicable aging effects.

Summary of the Review of Aging Effects Operating Experience

The staff has reviewed the information provided by the applicant regarding plant-specific, as well as industry-wide experience to support its identification of applicable aging effects. This included the description of the internal and external environments, and materials of fabrication for these systems. On the basis of this review, the staff concludes that the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.3.3.2 Aging Management Programs

Reactor Water Chemistry Control

The reactor water chemistry control program is an existing program at Plant Hatch that includes regular sampling, results analysis, and when applicable, chemistry modification of reactor water. In addition, the collected data are regularly trended, tracked, and evaluated. This program is credited for managing the aging effects of components in the HPCI system and the RCIC system. The staff's detailed review of this program is described in Section 3.1.1 of this SER. Based on its evaluation, pending satisfactory resolution of Open Item 3.1.1-1, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the reactor water environment.

Flow-Accelerated Corrosion Program

The FAC program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. This program includes prediction of susceptibility through modeling and testing to detect wall thinning, and is credited for managing the aging effects of components in the HPCI system and the RCIC system. The staff's detailed review of this program is described in Section 3.1.19 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel components exposed to the reactor water environment.

Treated Water Systems Piping Inspection

The treated water systems piping inspection is a new program at Plant Hatch that will provide for condition monitoring via one-time examinations intended to provide objective evidence that chemistry control is managing aging in piping that is not examined under another inspection program. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, RHR system, CS system, primary containment purge and inerting system, and SLCS. The staff's detailed review of this program is described in Section 3.1.24 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, and cast austenitic stainless steel components exposed to the reactor water, demineralized water, and suppression pool water environments. In addition, the staff finds this aging management program acceptable in managing the aging effects associated with stainless steel components exposed to a borated water environment.

Galvanic Susceptibility Inspections

Galvanic susceptibility inspection is a new program at Plant Hatch that will provide for condition monitoring via one-time inspections to objectively determine that galvanic susceptibility is being managed for specific components within the scope of license renewal. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, RHR system, CS system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.23 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel components exposed to the reactor water, demineralized water, suppression pool water, and river water environments.

Demineralized Water and Condensate Storage Tank Chemistry Control

The demineralized water and condensate storage tank chemistry control activities mitigate aging by monitoring fluid purity and composition in the makeup water to multiple systems. These activities are regular sampling, results analysis, and when applicable, chemistry modification. This program is credited for managing the aging effects of components in the HPCI system, RCIC system, and SLCS. The staff's detailed review of this program is described in Section 3.1.6 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the demineralized water and borated water environments.

Suppression Pool Chemistry Control

The suppression pool chemistry control activities mitigate aging in components exposed to the suppression pool water by controlling fluid purity and composition in the pool. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.7 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel components exposed to the suppression pool environment. In addition, the staff finds these activities acceptable in managing the aging effects associated with the RHR heat exchangers.

Protective Coatings Program

The protective coatings program is a mitigation and condition monitoring program that provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, primary containment purge and inerting system, SLCS, and SGTS. The staff's detailed review of this program is described in Section 3.1.20 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel components exposed internally to the borated water environment, and the external surfaces exposed to an inside environment. In addition, the staff finds these activities acceptable in managing the aging effects associated with bolting materials.

Torus Submerged Components Inspection Program

The torus submerged components inspection program is a condition monitoring activity that evaluates the effectiveness of the current suppression pool chemistry control in preventing loss of material and cracking. This program is credited for managing the aging effects of components in the RHR system, CS system, HPCI system, RCIC system, and primary containment purge and inerting system. The staff's detailed review of this program is described in Section 3.1.29 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel and stainless steel components exposed to the suppression pool environment.

Plant Service Water and RHR Service Water Chemistry Control

The PSW and RHRSW chemistry control activities mitigate aging in system piping and components by controlling fluid composition. Chlorination and bromination are coordinated with

periodic operation of the RHRSW to maximize chemical treatment. This program is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.4 of this SER. Based on its evaluation, pending satisfactory resolution of Open Item 3.1.4-1, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, clad carbon steel, stainless steel, cast austenitic stainless steel, and copper alloy components exposed to the river water environment. In addition, the staff finds these activities acceptable in managing the aging effects associated with the RHR heat exchangers.

Plant Service Water and RHR Service Water Inspection Program

The PSW and RHRSW inspection program is a condition monitoring program that is designed to detect wall thickness degradation or fouling in the PSW and RHRSW systems. This program is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.13 of this SER. Based on its evaluation, pending satisfactory resolution of Open Item 3.1.13-1, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, cast austenitic stainless steel, and copper alloy components exposed to the river water environment.

Structural Monitoring Program

The structural monitoring program provides for condition monitoring and appraisal of certain structures and structural components at Plant Hatch. This program is patterned after the Westinghouse Owners Group Life Cycle Management / License Renewal Program, and is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.22 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, clad carbon steel, stainless steel, cast austenitic stainless steel, and copper alloy components exposed to the river water environment.

Gas Systems Component Inspection

The gas system component inspection is a new activity that will provide for condition monitoring via a one-time condition monitoring aging management activity designed to provide objective evidence that the aging effects predicted for systems with gases as internal environments are adequately managed. This program is credited for managing the aging effects of components in HPCI system, primary containment purge and inerting system, RHR system, RCIC system, SGTS, and post-LOCA hydrogen recombiner system (Unit 2 only). The staff's detailed review of this program is described in Section 3.1.25 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, copper alloy, gray cast iron, and copper components exposed to a humid or wetted gas environment.

Passive Component Inspection Activities

The passive component inspection activities program comprises a new condition monitoring AMP that is designed to collect, report, and trend age-related data to determine the effectiveness of preventive or mitigative programs/activities credited for aging management. This program is credited for managing the aging effects of components in the RHR system, HPCI system, RCIC system, SGTS, primary containment purge and inerting system, and post-LOCA

recombiner system (Unit 2 only). The staff's detailed review of this program is described in Section 3.1.27 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon steel, stainless steel, cast austenitic stainless steel, and gray cast iron components exposed to a humid or wetted gas environment.

Torque Activities

The torque activities mitigate loss of preload through the use of proper torque techniques at Plant Hatch. Plant procedures specify techniques for maximizing the effectiveness of torque activities. This program is credited for managing the aging effects of bolts in the ESF systems. The staff's detailed review of this program is described in Section 3.1.11 of this SER. Based on its evaluation, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that this aging management program is acceptable in managing the aging effects associated with carbon and stainless steel bolting materials.

RHR Heat Exchanger Augmented Inspection and Testing Program

The RHR heat exchanger augmented inspection and testing program is a new activity that will provide for condition monitoring of both the shell and tube sides of the Units 1 and 2 RHR heat exchangers. This program is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.28 of this SER. Based on its evaluation, pending satisfactory resolution of Open Item 3.1.28-1, the staff concludes that this aging management program is acceptable in managing the aging effects associated with the RHR heat exchangers.

Inservice Inspection (ISI) Program

The ISI program is a condition monitoring program that provides for the implementation of ASME Section XI, in accordance with the provisions of 10 CFR 50.55a. This program also includes augmented examinations required to satisfy commitments made by the applicant, and is credited for managing the aging effects of components in the RHR system. The staff's detailed review of this program is described in Section 3.1.9 of this SER. Based on its evaluation, the staff concludes that this aging management program is acceptable in managing the aging effects associated with the RHR heat exchangers.

3.3.4 Conclusions

The staff has reviewed the information in Section 3.2.3, "Engineered Safety Features," of the LRA. On the basis of this review, pending satisfactory resolution of Open Items 3.1.1-1, 3.1.11-1, 3.1.13-1, and 3.1.28-1, the staff concludes that the applicant has adequately identified the aging effects, and has demonstrated that the aging effects associated with the ESF systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4 Auxiliary Systems

3.4.1 Introduction

The applicant provided the results of its AMR for the auxiliary systems for license renewal in Section 3.2.4, "Auxiliary Systems," and Section C.2 of the LRA. The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the auxiliary systems will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

Section 3.2.4 of the LRA contains six-column tables for each auxiliary system, which represents an overview of the aging management review results. The tables list the in-scope components of each system, along with each component's in-scope function, materials of construction, working environment, aging effects, and the associated aging management programs that are credited with managing the aging effects. The tables also reference the commodity group associated with each component. The commodity groups are described in Section C.2 of the LRA. Each commodity group is associated with a common environment and group of materials. The commodity groups, in turn, reference Section C.1 of the LRA, which provides a detailed discussion of the environments, materials and associated aging effects. The commodity groups also reference Section A of the LRA, which describes the aging management programs that manage the specified aging effects. The applicant submitted a supplemental description of its aging management programs in Section B of the LRA on October 10, 2000. The staff reviewed these sections of the application to determine whether the applicant presented adequate information to meet the requirements set forth in 10 CFR 54.21(a)(3).

External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.4.2 Summary of Technical Information in the Application

The applicant provided an aging management review of 20 auxiliary systems that are considered to be within the scope of license renewal. A brief description of each system is presented below.

Access Doors

The secondary containment access doors provide access for personnel and equipment. In addition, the secondary containment, in conjunction with the primary containment and other engineering safeguards, provides the capability to limit the release of radioactive materials to the environment.

Condensate Transfer and Storage System

The condensate transfer and storage system provides the plant system makeup, receives reject flow, and provides condensate for any continuous service needs and intermittent batch-type

services. A 500,000 gallon condensate storage tank (CST) supplies the various unit requirements. The CST provides the preferred supply to the HPCI and RCIC systems.

Control Building Heating Ventilation and Air Conditioning (HVAC) System

Under normal and post-accident plant conditions, the control building HVAC system controls s temperature and air movement, filters fresh-air supply for personnel comfort, removes heat from the plant equipment to optimize performance, minimizes the potential for exhaust air to enter the supply air, and detects and limits the introduction of radioactive material into the main control room. The control room HVAC system provides cooling and maintains a controlled environment for personnel safety and habitability in the control room during normal and accident conditions. The system also provides a controlled temperature to ensure the reliability of the main control room components.

Control Rod Drive System

The control rod drive (CRD) hydraulic system provides pressurized, demineralized water for the cooling and manipulation of the CRD mechanisms. The CRD system also provides purge water for the reactor water cleanup pump and reactor recirculation pump seals. The alternate rod insertion system is a subsystem of the CRD system. It is a backup means of scramming the reactor by venting the scram air header. The alternate rod insertion system is independent of the reactor protection system, and was installed to reduce the probability of an anticipated transient without scram event.

Cranes, Hoists, and Elevators System

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. The reactor building crane moves major components for refueling operations and maintenance. The Unit 1 reactor building crane provides service to both Unit 1 and Unit 2.

Drywell Pneumatics System

The drywell pneumatics system supplies the motive gas to various valves inside the drywell.

Emergency Diesel Generators System

The emergency diesel generators provide emergency backup power to 4160-V ac emergency buses E, F, and G in the event of a loss of loss of offsite power.

Fire Protection System

The fire protection system ensures, through a defense-in-depth design, that a fire will not prevent the necessary safe plant shutdown functions from occurring. The program also decreases the risk of radioactive releases to the environment during a fire. The program consists of detection and extinguishing systems, administrative controls and procedures, and trained personnel. The applicant gave the primary design consideration to locating redundant safe shutdown circuits and components in distinct areas separated by fire barriers to prevent the propagation of fire to adjacent areas. Fire barriers consist of fire-rated doors, dampers, and penetration seals. The barriers are designed to contain a design-basis fire. The fire protection program at Plant Hatch also includes an early warning fire detection system. Two 300,000-gallon dedicated storage tanks provide the water supply for the fire protection system inside the

protected area. These tanks, in turn, are supplied by two deep wells with strained and filtered water supplies for normal makeup. The fire protection system also includes cardox fire suppression for the emergency diesel generators to provide an automatic gaseous total flooding fire suppression system for a diesel engine compartment fire to contain and control the level of fire damage, and an automatic gaseous fire suppression system for the computer room and the cable spreading room. This is a total flooding system actuated by ionization detection.

Fuel Oil System

The fuel oil system receives, stores, and supplies fuel oil to other systems including the emergency diesel generator system.

Instrument Air System

The instrument air system provides dried and filtered air to all of the air-operated instruments and valves throughout the entire plant (with the exception of the equipment inside the drywell). This system is made up of two subsystems, one of which is non-interruptible, while the other is interruptible. The non-interruptible system provides instrument air for the operation of emergency system components. The interruptible system provides instrument air to all other components. The drywell pneumatic system (discussed in more detail below) supplies the motive gas for components within the drywell.

Insulation System

Insulation helps to retain heat in the process piping and equipment, to prevent moisture from condensing on cold surfaces, to protect equipment and personnel from high temperatures, to prevent piping from freezing in cold areas of the plant, and to protect heat tracing from damage. The applicant also credits insulation in heat load calculations for safety-related rooms. Failure of this insulation could allow the heat load of the room to exceed the capability of the HVAC system, thus exceeding the design temperature of the room.

Outside Structures HVAC System

This group includes the intake structure HVAC and the diesel generator building HVAC systems. The intake structure HVAC system protects the intake structure equipment from adverse temperature conditions that could affect the reliability of the equipment. The diesel generator building HVAC system protects diesel generator building equipment from adverse temperature conditions that could affect the reliability of the equipment. In addition, the emergency diesel generator battery room ventilation system exhausts hydrogen from the battery rooms, and the emergency diesel generator building oil storage room ventilation exhausts fumes from the oil storage room in the event of fire.

Plant Service Water System

The plant service water system removes the heat that is generated from various systems. This system provides circulating water system makeup from screened Altamaha River water and, after cooling heat exchangers, provides makeup water to the circulating water flume. This system is also available for fire-fighting, radwaste dilution, and emergency spent fuel pool makeup.

Primary Containment Chilled Water System (Unit 2 Only)

The primary containment chilled water system maintains the drywell area below a maximum volumetric average temperature of 150°F dry bulb during normal operation. This function is fulfilled by providing chilled water to the drywell fan coil units. Reactor building service water provides the chiller condenser cooling water, while demineralized water provides makeup for the system.

Reactor Building Closed Cooling Water System

The reactor building closed cooling water system provides cooling water to auxiliary equipment located in the reactor building.

Reactor Building HVAC System

The reactor building HVAC system performs many functions. It provides an environment with controlled temperature and airflow to ensure the comfort and safety of operating personnel and to optimize equipment performance by removing heat from the plant equipment. It promotes air movement from operating areas and areas of lower airborne radioactivity potential to areas of greater airborne radioactivity potential prior to final filtration and exhaust. It minimizes the release of potential airborne radioactivity to the environment during normal plant operation by exhausting air, through a filtration system, from the areas in which a significant potential for radioactive particulates and/or radioiodine contamination exists. It provides a source of cooling to support the operation of the emergency core cooling systems. Lastly, the system provides isolation capability to maintain secondary containment integrity and support operation of the standby gas treatment system. The reactor building HVAC system uses a combination of air conditioning, heating, and once-through ventilation. Heat removal is provided by ventilation air and chilled-water (Unit 2 only) and service-water cooling coils served by the reactor and radwaste building chilled water system and the plant service water system, respectively. Hot water heating coils, served by the plant heating system, are supplied for heating.

Refueling Equipment System

The refueling platform equipment assembly handles and transports reactor core internals and service and handling equipment associated with the refueling operation. The refueling platform is a bridge structure that spans the refueling pool and the reactor well and travels on rails which extend the length of the fuel storage pool and the reactor well. The fuel grapple extends downward, below the underside of the refueling platform, into the pool or reactor well.

Sampling System

The primary containment hydrogen and oxygen sampling system monitors hydrogen and oxygen in the primary containment (drywell and torus).

Tornado Vents System

The tornado vents act as blowout panels for venting the reactor and control building roofs (1) against a wind velocity of 300 mph, (2) when the internal static pressure in the building is increased to 55 lb/ft^2, or (3) when the temperature reaches approximately 212 °F. A rapid depressurization of air surrounding site structures can occur if a tornado funnel suddenly engulfs

a structure. Venting is accomplished by placing blowout panels, designed to fail at a pressure lower than the safe building capability for internal pressure, to relieve excess pressure in all essential parts of such structures.

Traveling Water Screens/Trash Racks System

The intake structure is equipped with trash screens and rakes to keep debris out of the pump wells. The traveling water screens prevent debris from entering the portion of the intake structure from which the pumps take suction. Larger debris is prevented from reaching the screens by the trash racks. The debris is removed from the screens by the screen wash water.

3.4.2.1 Aging Effects and Aging Management Programs

The applicant discussed the aging effects and aging management programs for the various auxiliary system components and environments at Plant Hatch in Sections C.1 and C.2 of the LRA. The applicant approached its aging management review in a manner that the staff and industry commonly refer to as the commodity group approach. Commodities are groups of structures or components that have similar intended functions and materials of construction and operate in similar environments. Because they are similar in material and environment, they can experience common aging effects, and common aging management programs can be credited for managing those aging effects. This approach is intended to achieve efficiency in the aging management review process. There are more than 20 commodity groups related to auxiliary systems because of the wide variety of environments that exist in the auxiliary systems. Therefore, the staff chose to present the applicant's aging management review based on environment, rather than commodity group, in order to consolidate and streamline this SER. These environments include demineralized water, dried and wetted gases, inside (sheltered) and outside (nonsheltered), raw water (including submerged components), closed cooling water, concrete embedment, and fuel oil environments. Each of these environments, the materials exposed to these environments, and the associated aging effects and aging management programs identified by the applicant are summarized below.

Demineralized Water

Demineralized water at Plant Hatch contains no corrosion inhibiting chemical or biocide additions, and provides no control of dissolved oxygen concentrations. Acceptable levels for impurities vary among systems driven by the relative potential for any given system to supply water to the reactor pressure vessel. Three auxiliary systems (control rod drive system, condensate transfer and storage system, and emergency diesel generators system) contain stainless steel, cast austenitic stainless steel, carbon steel, galvanized steel, or aluminum alloy components exposed to a demineralized water environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a demineralized water environment in section C.2.2.2 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, pitting, and erosion corrosion). To manage this aging effect, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- condensate storage tank inspection

Dried and Wetted Gases

The applicant defined the gas environment as any line that contains noncondensable gases and includes both dried and nondried (wetted) gases. Dried gases describe any process gas including, but not limited to, air, nitrogen (including cryogenic), carbon dioxide, hydrogen, helium, and fluorocarbons supplied from a tank or bottle or filtered and desiccated to remove moisture prior to entering the system. Five auxiliary systems (control rod drive system, instrument air system, drywell pneumatics system, fire protection system, and the control building HVAC system) contain carbon steel, stainless steel, or copper/copper alloy components exposed to a dried gas environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a dried gas environment in Section C.2.2.8 and section C.2.3.3 of the LRA. Because sufficient moisture to drive the various corrosion mechanisms is not present, there are no aging effects that require management and, therefore, no aging management programs were identified.

Wetted gases include air or nitrogen containing humidity or significant moisture. Wetted gas environments are found inside of buildings, inside the drywell, and outside of buildings. These gases are assumed to contain sufficient entrained moisture and oxygen to enable pooling of liquid at low or especially cool locations and promote corrosion. Eight auxiliary systems (control rod drive system, sampling system, emergency diesel generator system, reactor building HVAC system, outside structures HVAC system, fire protection system, fuel oil system, and control building HVAC system) contain carbon steel, stainless steel, galvanized steel, copper/copper alloy, aluminum, or cast iron components, as well as gasket materials exposed to a wetted gas (this includes air) environment. The applicant discussed the aging management review for the auxiliary system structures and components exposed to a wetted gas environment in Section C.2.2.9 Section C.2.3.3 and Section C.2.6.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, selective leaching, galvanic corrosion, crevice corrosion, MIC, and pitting). The applicant also identified cracking of gasket materials due to compaction and settling, exposure to moisture, and thermal effects. To manage these aging effects, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities
- fire protection activities

Inside and Outside Environments

An inside environment indicates that the equipment is sheltered from the weather. The inside environment (except for primary containment) assumes 50% to 90% humidity, an ambient temperature less than 120°F, and a maximum radiation level of 9.0×10^6 rads. The primary containment environment assumes 40% to 90% humidity, a maximum temperature of 150°F and a maximum radiation level of 9.17×10^7 rads outside the sacrificial shield wall. The applicant defines “outside” as any external environment found outside any structure that would protect it from the weather. The applicant assumes 0% to 100% humidity, an ambient temperature less than 120°F, and no radiation.

Eighteen auxiliary systems (control rod drive system; refueling equipment system; insulation system; access doors; condensate transfer and storage system; plant service water system; reactor building closed cooling water system; instrument air system; primary containment chilled water system; drywell pneumatics system; cranes, hoists and elevators system; tornado vents system; reactor building HVAC system; traveling screen/trash rack system; outside structures

HVAC system; fire protection system; fuel oil system; and control building HVAC system) contain carbon steel, aluminum, stainless steel, acrylic, galvanized steel, cast iron, ceramic, copper/copper alloy, or various insulating/gasket type materials or specialized fire protection materials exposed to an inside (sheltered) and/or outside (nonsheltered) environment. The applicant discussed the aging management review of these materials in these environments in Sections C.2.2.10, C.2.6.3, C.2.4.4, C.2.4.1, C.2.6.6, C.2.6.8, C.2.3.4, and C.2.6.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, and pitting). The applicant identified loss of preload as an applicable aging effect for bolting due to embedment, gasket creep, thermal effects, or self loosening. The applicant identified cracking of acrylic due to weathering as well as cracking, and change in material properties for insulating/gasket type materials due to compaction and settling, exposure to moisture, and thermal effects. To manage these aging effects, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program
- structural monitoring program
- overhead crane and refueling platform inspections
- equipment and piping insulation monitoring program
- fire protection activities
- gas systems component inspections
- passive component inspection activities

<u>Raw Water</u>

Plant Hatch has two sources of raw water, including river water and well water. River water is supplied from the Altamaha River via the intake structure. The structure has rough screens in place to prevent clogging of the vertical turbine pumps and discharge strainers. Some debris, silt, and macroorganisms may be introduced into the plant service water and residual heat removal service water systems. Well water is supplied from deep draft wells located on site. The water is mechanically filtered using the demineralizing system filters to remove macroorganisms and silt. Well water is used for the fire protection system only. Three auxiliary systems (plant service water system, traveling water screens/trash rack system, and the fire protection system) contain stainless steel, carbon steel, cast austenitic stainless steel, cast iron, copper alloys, galvanized steel, or aluminum components exposed to a raw water environment. The applicant discussed the aging management review of these materials in this environment in Section C.2.2.6, Section C.2.6.3, and Section C.2.3.1 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting) and flow blockage due to fouling. To manage these aging effects, the applicant relies on the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control
- structural monitoring program
- galvanic susceptibility inspections
- protective coatings program
- fire protection activities

Closed Cooling Water

Plant Hatch monitors the closed cooling water for detrimental impurities, although the parameters are less restrictive than those for reactor water or auxiliary system water environments. The applicant adds corrosion inhibitors to reduce the corrosion rate to an acceptable level. A basic pH is maintained to increase the effectiveness of the corrosion inhibitors and promote the development of protective corrosion films. Plant Hatch maintains biocide levels to prevent significant microorganism growth. Two auxiliary systems (the reactor building closed cooling water system and the primary containment chilled water system) have carbon steel, stainless steel, and copper alloy components exposed to a closed cooling water environment. The applicant discussed the aging management review of the materials in this environment in Section C.2.2.5 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting). To manage this aging effect, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspections

Embedded in Concrete

The fire protection system contains penetration seals embedded in concrete. The applicant discussed the aging management review in Section C.2.3.4 of the LRA. Aging effects that require management include loss of material due to corrosion (e.g., general corrosion, crevice corrosion, and pitting) or wear and fretting, cracking within concrete/fire barrier materials due to thermal effects and/or compaction and settling, and change in material properties of fire barrier materials due to thermal degradation. To manage these aging effects, the applicant relies on the fire protection activities program.

Fuel Oil

Fuel oil is any oil utilized to fuel an internal combustion engine. Two auxiliary systems (fire protection system and the fuel oil system) contain carbon steel, stainless steel, copper/copper alloy and cast iron components exposed to a fuel oil environment. The applicant discussed the aging management review of these materials in this environment in Section C.2.3.2 and Section C.2.2.7 of the LRA. The applicant identified several forms of corrosion that may result in loss of material (e.g., general corrosion, galvanic corrosion, crevice corrosion, MIC, and pitting). To manage this aging effect, the applicant relies on the following aging management programs:

- diesel fuel oil testing
- fire protection activities

External Environments

The auxiliary system environments discussed above are based on the dominant operating environment of the components which, generally speaking, is the internal environment (e.g., raw water running through piping). The applicant discussed the aging effects due to external environments in Section C.2.4 of the LRA. These external environments include inside, outside, buried or embedded, and a special section for insulation commodities. The staff's evaluation of the applicant's treatment of aging effects caused by external environments can be found in Section 3.6 of this SER, and are generally not discussed for the auxiliary system structures and

components in this section. However, when the external environment is the dominant operating environment for the structure or component, the aging effects and associated aging management programs are included in this section of the SER.

Thermal Fatigue

The applicant identified cracking due to thermal fatigue as an aging effect for the auxiliary system components. The applicant stated that all non-Class 1 components are enveloped by a time-limited aging analysis that adequately addresses this aging effect without regard to individual component or system conditions. The applicant discusses this analysis in Section 4.2.3 of the LRA. The staff's evaluation of this analysis is in Section 4.2 of this SER.

Operating Experience

The applicant stated it collected industry operating experience from sources such as NRC generic letters, bulletins and information notices; General Electric service information letters; Institute on Nuclear Power Operations (INPO) significant operating event reports; and topical information from various industry working groups. The applicant obtained plant-specific information through plant walkdowns, interviews, and records searches of their condition reporting database that covers the last 5 years of operation. The applicant presented brief discussions of this operating experience, both plant-specific and industry-wide, in each commodity group.

The applicant concluded that it identified the appropriate aging effects and associated aging management programs that would ensure that the intended function of the components of the auxiliary systems would be maintained consistent with the current licensing basis, under all design loading conditions during the period of extended operation.

3.4.3 Staff Evaluation

The applicant described its aging management review of the auxiliary systems for license renewal in Section 3.2.4 and Sections A, B (submitted October 10, 2000), and C of the LRA. The staff reviewed these sections of the application to determine whether the applicant presented adequate information to meet the requirements stated in 10 CFR 54.21(a)(3). In this section of the safety evaluation report, the staff provides its evaluation of the aging management review for the auxiliary systems.

3.4.3.1 Aging Effects

Access Doors

Access doors consist of structural carbon steel exposed to inside and outside environments. The applicant identified loss of material as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Condensate Transfer and Storage System

The condensate transfer and storage system contains components exposed to a demineralized water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a demineralized water environment. The condensate

transfer and storage system also contains stainless steel bolting exposed to an outside environment. The applicant identified loss of preload as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Control Building HVAC System

The control building HVAC system contains both metallic and nonmetallic components exposed to an air (potentially wetted) environment. For the metallic components, the applicant identified loss of material as an applicable aging effect. For the nonmetallic components, the applicant identified material property changes as an applicable aging effect. This system also contains components exposed to a dried gas environment. The applicant identified no aging effects associated with component materials in a dried gas environment. Lastly, the control building HVAC system contains carbon steel bolting exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and the associated Open Item 3.1.11-1, may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the control building HVAC system.

Control Rod Drive System

The CRD system contains components exposed to a demineralized water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a demineralized water environment. The CRD system also contains components exposed to a dried gas environment. The applicant identified no aging effects associated with CRD component materials in a dried gas environment. The CRD system also contains components exposed to a wetted gas environment. The applicant identified loss of material as an applicable aging effect. The CRD system contains carbon and low alloy carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1, may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the CRD system.

Cranes, Hoists and Elevators System

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. The reactor building crane contains carbon steel components exposed to an inside environment. The applicant identified loss of material as an applicable aging effect. The staff agrees with the applicant's identification of aging effects.

Drywell Pneumatics System

The drywell pneumatics system contains components exposed to a dried gas environment. The applicant identified no aging effects associated with component materials in a dried gas environment. This system also contains carbon steel and stainless steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1, may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the drywell pneumatics system.

Emergency Diesel Generators System

The emergency diesel generator (EDG) system contains components exposed to a demineralized water environment. The applicant identified loss of material as an applicable aging effect associated with the component materials in a demineralized water environment. The EDG system also has carbon and stainless steel components exposed to a wetted gas environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a wetted gas environment. In Table 3.2.4-12 of the LRA, the applicant did not identify loss of preload as an aging effect for bolting in the EDG system. In RAI 3.4-10(c), dated July 28, 2000, the staff requested that the applicant provide the basis for excluding loss of preload as an aging effect for bolting in the EDG system. The applicant responded to this RAI in its letter dated October 10, 2000. Specifically, the applicant stated that bolting is not a separate mechanical component/commodity requiring aging management for the EDG system. This issue regarding the treatment of the bolting for the EDGs will be resolved as part of the resolution of Open Item 2.3.3.2-1 in Section 2.3.4 of this SER.

On the basis of the information provided by the applicant in the LRA, pending satisfactory resolution of Open Item 2.3.3.2-1, the staff concludes that the applicant has adequately identified the aging effects associated with the EDG system.

Fire Protection System

The fire protection system contains many components fabricated from various materials and exposed to an inside environment. The applicant identified loss of material and cracking as applicable aging effects for the carbon steel, nonferrous metal, ceramic and organic components. The applicant also identified a change in material properties for insulating materials and penetration seals. The applicant did not identify any aging effects for fire doors constructed from materials other than carbon steel for which loss of material is an applicable aging effect. The fire protection system also has components exposed to raw water. The applicant identified loss of material and flow blockage as applicable aging effects associated with component materials in a raw water environment. The fire protection system also has components exposed to fuel oil. The applicant identified loss of material as an applicable aging effect associated with component materials in a fuel oil environment. Finally, the fire protection system has components exposed to either a dried gas or an air (potentially wetted) environment.

The applicant identified no aging effects for components exposed to a dried gas environment. For those components exposed to an air environment, the applicant identified loss of material as an applicable aging effect.

The fire protection system also contains carbon steel bolting exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue, and associated Open Item 3.1.11-1, may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satsisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the fire protection system.

Fuel Oil System

The fuel oil system contains components exposed to a fuel oil environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a fuel oil environment. Lastly, the fuel oil system contains components exposed to an air (potentially wetted) environment. The applicant identified loss of material as an applicable aging effect associated with component materials in an air (potentially wetted) environment.

The fuel oil system also contains carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1, may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the fuel oil system.

Instrument Air System

The instrument air system contains components exposed to a dried gas environment. The applicant identified no aging effects associated with component materials in a dried gas environment. The instrument air system also contains carbon and stainless steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the instrument air system.

Insulation System

The insulation system contains metallic and insulating components exposed to inside and outside environments. The applicant identified loss of material as an applicable aging effect for the metallic components in these environments. The applicant also identified, for the insulation, loss of material due to intrusion of water or wear, cracking due to thermal degradation or intrusion of water, and a change in material properties due to compaction or settling. The staff agrees with the applicant's identification of aging effects.

Outside Structures HVAC System

The outside structures HVAC system contains components exposed to an air (potentially wetted) environment. The applicant identified loss of materials as an applicable aging effect associated with component materials in an air (potentially wetted) environment. The system also contains carbon steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the outside structures HVAC system.

Plant Service Water System

The plant service water system contains a carbon steel pump sub-base exposed to an inside environment. The applicant identified loss of material as an applicable aging effect.

The plant service water system contains components exposed to a raw water (river water) environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a raw water environment. The applicant also identified flow blockage as an applicable aging effect due to corrosion product buildup, biofouling, particulate fouling, or precipitation fouling. The plant service water system also contains carbon and low-alloy steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of the Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the plant service water system.

Primary Containment Chilled Water System (Unit 2 Only)

The primary containment chilled water (PCCW) system contains components exposed to the closed cooling water environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a closed cooling water environment. The PCCW system also contains carbon steel bolts exposed to an inside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the primary containment chilled water system (Unit 2 only).

Reactor Building Closed Cooling Water System

The reactor building closed cooling water system contains components exposed to a closed cooling water environment. The applicant identified loss of material as an applicable aging effect associated with the component materials in a closed cooling water environment. This system also contains carbon and low-alloy carbon steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the reactor building closed cooling water system.

Reactor Building HVAC System

The reactor building HVAC system contains components exposed to an air (potentially wetted) environment. The applicant identified loss of material as an applicable aging effect associated with component materials in an air (potentially wetted) environment. This system also contains carbon steel bolts exposed to inside and outside environments. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the reactor building HVAC system.

Refueling Equipment System

The refueling equipment system contains components exposed to an inside environment. The applicant identified loss of material as an applicable aging effect associated with the component materials in an inside environment. The staff agrees with the applicant's identification of aging effects.

Sampling System

The sampling system contains components exposed to a wetted gas environment. The applicant identified loss of material as an applicable aging effect associated with component materials in a wetted gas environment. The staff agrees with the applicant's identification of aging effects.

Tornado Vents System

The tornado relief vent assemblies contain metallic and acrylic components exposed to an inside and outside environment. The applicant identified no aging effects for the metallic components. The applicant identified cracking as an applicable aging effect for the acrylic components. The staff agrees with the applicant's identification of aging effects.

Traveling Water Screens/Trash Racks System

The traveling water screens/trash rack system contains components exposed to or submerged in raw water. The applicant identified loss of material and fouling as applicable aging effects associated with component materials in a raw water environment. This system also contains carbon steel bolts exposed to an outside environment. The applicant identified loss of material and loss of preload as applicable aging effects for bolting. In RAI 3.4-1, dated July 28, 2000, the staff requested that the applicant provide the technical justification for not including SCC as an applicable aging effect for high-strength bolting materials. The applicant submitted a response to this RAI on October 10, 2000; however, the staff found the response unacceptable. A full discussion of this issue and associated Open Item 3.1.11-1 may be found in Section 3.1.11 of this SER.

On the basis of the information provided by the applicant in the LRA, and pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has adequately identified the aging effects associated with the traveling water screens/trash racks system.

Vibration Loading

The applicant did not identify cracking due to vibration loading as an aging effect for the auxiliary system components. The staff is aware that some piping system degradation (e.g., loss of integrity of bolted closures, cracking of welds, and loosening of bolts) may be caused by vibration (mechanical or hydrodynamic) loading. In many tables in Section 3.2.4 of the LRA, the applicant identified loss of preload as an aging effect for bolting. In Section C.1 of the LRA, the applicant indicated that loss of preload included self-loosening of bolting that may be caused by vibration. Thus, the staff was not clear whether the applicant had considered cracking of auxiliary system components (in particular piping welds and HVAC ducting) that may be subjected to a high-vibration environment. In RAI 3.4-10(b), dated July 28, 2000, the staff requested that the applicant clarify whether it had considered these vibration related aging effects in the AMR for the auxiliary systems discussed in Section 3.2.4 of the LRA. The

applicant responded to the staff's RAI in its letter dated October 10, 2000, stating that vibration-induced cracking in piping welds and HVAC ducting is indicative of an insufficient design or failure to follow good bolting practices following maintenance, neither of which is age-related. Therefore, the applicant concluded that vibration-induced cracking is not an applicable aging effect. It should be noted that the control building HVAC system includes elastomeric isolators. Elastomers may crack, harden, or lose strength due to relative motion between vibrating equipment, exposure to warm moist air, temperature changes, oxygen, and/or radiation. If these isolators degrade, vibration and subsequent dynamic loads applied to the ductwork and fasteners cannot be eliminated. The applicant considered the degradation of elastomeric isolators, including gaskets and flexible connectors, in the control building HVAC system. The isolators are shown in Table 3.2.4-20 of the LRA as "ductwork flex connectors," and the aging management review is presented in Section C.2.6.7 of the LRA. By including the isolators in the aging management review for this system, the staff finds that the applicant has adequately addressed the potential for vibration-related aging effects for the control building HVAC system. In RAI 3.4-12, the staff also requested that the applicant discuss how this potential aging effect is managed for the reactor building HVAC system. In its submittal dated October 10, 2000, the applicant clarified that the reactor building HVAC system design is such that isolators are not required. As this design has demonstrated acceptable operating experience, the staff concludes that vibration-related aging effects are not applicable to the reactor building HVAC system. The staff finds that the applicant's responses adequately address the vibration-related aging effects for auxiliary systems.

External Environments

The applicant discussed the aging effects due to external environments in Section C.2.4 of the LRA. These external environments include inside, outside, and buried or embedded environments, and a special section for insulation commodities. The staff's evaluation of the applicant's treatment of aging effects caused by external environments can be found in Section 3.6 of this SER, and are generally not discussed for the auxiliary system structures and components in this section. However, when the external environment is the dominant operating environment for the structure or component, the aging effects and associated aging management programs are included in this section of the SER.

Thermal Fatigue

The applicant identified cracking due to thermal fatigue as an aging effect for the auxiliary system components. The applicant stated that all non-Class 1 components are enveloped by a time-limited aging analysis that adequately addresses this aging effect without regard to individual component or system conditions. The applicant discusses this analysis in Section 4.2.3 of the LRA. The staff's evaluation of this analysis is in Section 4.2 of this SER.

Summary of the Review of Aging Effects' Operating Experience

The staff has reviewed the information presented by the applicant regarding plant-specific, as well as industry-wide, experience to support its identification of applicable aging effects. This included the description of the internal environments and materials of fabrication for these systems. On the basis of the information, and upon satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the applicant has identified the aging effects for the commodity groups in the auxiliary systems that are consistent with published literature and industry experience.

3.4.3.2 Aging Management Programs

Access Doors

To manage aging effects for structural carbon steel components exposed to either an inside or outside environment, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. In addition, the carbon steel access doors are coated with an inorganic zinc primer and epoxy topcoat or are galvanized steel. The protective coatings program provides for periodic inspection of component surfaces to ensure that this coating is intact and providing adequate protection. This program also provides for proper corrective actions to prevent significant degradation (e.g., replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.22 and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Condensate Transfer and Storage System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections is a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating the loss of material within carbon steel and stainless piping. The staff's detailed review of these programs may be found in Sections 3.1.6 and 3.1.24 of this SER.

To manage loss of preload for stainless bolting exposed to an outside environment, the applicant relies on the torque activities program, which provides detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. The staff's detailed review of this program may be found in Section 3.1.11 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Control Building HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Control Rod Drive System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections (for carbon steel components only)

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections comprise a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating loss of material within carbon steel and stainless steel piping. The galvanic susceptibility inspections comprise another one-time inspection

program to examine carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.24, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for components exposed to a wetted gas environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Cranes, Hoists and Elevators Systems</u>

The reactor building crane is the only in-scope component for the cranes, hoists, and elevators system. To manage aging effects for carbon steel components exposed to an inside environment, the applicant relies on the following aging management programs:

- overhead crane and refueling platform inspection
- protective coatings program
- structural monitoring program

The overhead crane and refueling platform inspection provides for regular, periodic visual inspections of the reactor building crane. The protective coatings program provides for periodic visual inspections of component external surfaces. This program also provides for proper

corrective actions to prevent significant degradation of the reactor building crane components due to general corrosion (such as replacement or coating of exposed surfaces). The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. The staff's detailed review of these programs may be found in Sections 3.1.10, 3.1.22, and 3.1.20 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Drywell Pneumatics System

To manage aging effects for carbon steel and stainless steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Emergency Diesel Generator System

To manage aging effects for components exposed to a demineralized water environment, the applicant relies on the following aging management programs:

- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections

The demineralized water and condensate storage tank chemistry control program serves to manage loss of material due to corrosion by limiting concentrations of impurities, total organic carbon, and conductivity. The treated water systems piping inspections comprise a one-time inspection program to validate the adequacy of the demineralized water and condensate storage tank chemistry control program in mitigating the loss of material within carbon steel and stainless steel piping. The galvanic susceptibility inspections comprise another one-time inspection program to examine carbon steel to stainless steel dissimilar metal welds to identify potential loss of material due to galvanic corrosion. The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.24, and 3.1.23 of this SER.

To manage aging effects for components in a wetted gas environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Fire Protection System</u>

To manage aging effects for carbon steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11, and 3.1.20 of this SER.

To manage aging effects for components exposed to the various environments (inside, raw water, air, fuel oil) that exist within the fire protection system, the applicant relies on the fire protection activities program, which consists of inspection, condition monitoring and performance monitoring activities. These activities are geared for the specific environment, be it an inside, raw water, air, or fuel oil environment. The staff's detailed review of this program may be found in Section 3.1.18 of this SER.

To manage aging effects for the carbon steel tank exposed to raw water, in addition to the fire protection activities, the applicant relies on the protective coatings program, which prevents corrosion within the fire water storage tank by maintaining sufficient coating on the internal surfaces of the storage tank. The staff's detailed review of this program may be found in Section 3.1.20 of this SER.

To manage aging effects for components exposed to fuel oil, in addition to fire protection activities, the applicant relies on the diesel fuel oil testing program, which samples and analyzes

fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. Water and sediment contamination levels within storage tanks are checked on a regular basis to ensure that no significant buildup of contaminants exists. The staff's detailed review of this program may be found in Section 3.1.3 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Items 3.1.3-1 and 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Fuel Oil System

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for components exposed to fuel oil, the applicant relies on the diesel fuel oil testing program, which samples and analyes fuel oil deliveries for water and sediment contamination. Biocides are also added at this time in order to minimize the potential for MIC within components. The staff's detailed review of this program may be found in Section 3.1.3 of this SER.

To manage aging effects for components exposed to an air environment, the applicant uses the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Items 3.1.3-1 and 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Instrument Air System

To manage aging effects for carbon steel and stainless steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Insulation System

To manage aging effects for insulation system components exposed to either an inside or outside environment, the applicant relies on the equipment and piping insulation monitoring program, which consists of visual inspections of in-scope components exposed to either an inside or outside environment. The insulation inspection looks for holes, tears, compaction, material separation, wetting, missing insulation, and general deterioration. Jackets and fasteners will also be visually inspected for loss of material and cracking. The staff's detailed review of this program may be found in Section 3.1.21 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Outside Structures HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the following aging management programs:

- gas systems component inspections
- passive component inspection activities

The applicant designed both of these programs to address corrosion-related aging degradation in gas-bearing systems. The gas systems component inspections program is a new, one-time inspection program that inspects a sample of components that are considered unlikely (e.g., stainless steel components) to suffer age-related degradation. In contrast, the passive component inspection activities provide for the inspection of normally inaccessible components during maintenance activities. This latter program is for those components that are considered more likely to suffer age-related degradation. The staff's detailed review of these programs may be found in Sections 3.1.25 and 3.1.27 of this SER.

To manage aging effects for carbon and stainless steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Plant Service Water System</u>

To manage aging effects for components exposed to a raw water environment, the applicant relies on the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control program
- structural monitoring program
- galvanic susceptibility inspections

The plant service water and residual heat removal service water inspection program is a condition monitoring program designed to detect wall thickness degradation or fouling in the plant service water and residual heat removal service systems. The plant service water and residual heat removal service water chemistry control program mitigates aging in system piping and components by controlling fluid composition through treatment with sodium hypochlorite and sodium bromide. The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. The aging effects of plant service water system carbon steel components in the river water environment are further managed by the galvanic susceptibility inspections. These are one-time inspections to provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The staff's detailed review of these programs may be found in Sections 3.1.13, 3.1.4, 3.1.22, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings

program provides for periodic inspection of component external surfaces, including fasteners. This program will also provide for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

To manage aging effects for the carbon steel pump sub-base externally exposed to an inside environment, the applicant relies on the following aging management program:

- protective coatings program

The protective coatings program provides for periodic inspection of component external surfaces, including the carbon steel pump sub-base. This program will also provide for proper corrective actions to prevent significant degradation of the sub-base due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of this program may be found in Section 3.1.20 of this SER.

The staff conducted a scoping inspection in the offices of SNC from September 11, 2000 through September 15, 2000. The results of the inspection are documented in Inspection Report 50-321/00-09, 50-366/00-09. During the inspection, the inspectors identified a guard pipe associated with Division I plant service water piping in the diesel generator building. This guard pipe had not been considered for scoping and screening in the LRA. In response to this inspection finding, the applicant evaluated the guard pipe and concluded that it did not perform an intended function, and therefore was not within the scope of license renewal. The staff agreed with this conclusion. The staff's review of the applicant's evaluation of the guard pipe can be found in Section 2.3.4 of this SER. The internal surface of the PSW piping is exposed to raw water, and thus the aging effects and aging management programs are consistent with other piping sections in this system. However, the portion of the PSW piping surrounded by the guard pipe is welded to the guard pipe at both ends. Thus, the external surface of this section of plant service water piping is not easily accessible for inspection. The applicant plans to perform a one-time inspection to assess the material condition of the external surfaces of this piping section. The staff requests the applicant to provide appropriate information about this one-time inspection prior to the end of the current term. This is Open Item 3.1.13-1.

In RAI 3.4-9, dated July 28, 2000, the staff noted that the applicant stated in the LRA that selective leaching was a corrosion mechanism that may result in loss of material for brass and gray cast iron components exposed to a raw water environment in the plant service water and fire protection systems. Given that selective leaching may not be detectable through standard visual inspections, the staff asked the applicant to discuss how the various inspection and testing programs are adequate to manage the aging effect (loss of material) resulting from this aging mechanism. In its October 10, 2000 response, the applicant stated that no age-related failures were identified for these components in the plant's operating history. In addition, for susceptible components in the fire protection system, the components' functionality is closely linked to performance characteristics that are currently monitored though fire protection activities. The staff agrees that the fire protection activities provide reasonable assurance of component functionality. For susceptible components in the plant service water system, the applicant committed to additional activity. The applicant provided additional information regarding this activity in its letter dated January 31, 2001. The applicant will either perform a Brinell hardness test, or a metallurgical analysis, on one plant service water component from each commodity (brass and gray cast iron) in existence at Plant Hatch within the time frame of August 6, 2009 to August 6, 2014 for Unit 1, and June 13, 2013 and June 13, 2018 for Unit 2.

The results will be compared to the design code of record as well as available textbook and vendor data. The scope and timing of the activity appear to the staff to be reasonable, given that selective leaching has not been identified at Plant Hatch. Also, the staff agrees that Brinell hardness testing and metallurgical analysis are both widely acceptable means of determining if selective leaching is occurring. The acceptance criteria are reasonable and consistent with staff expectations and current industry practice. In summary, the staff finds the applicant's stated approach satisfactory to manage selective leaching for components in the plant service water system. The applicant incorporated a one-time inspection into the PSW and RHRSW inspection program.

On the basis is the above information, and upon satisfactory resolution of the Open Items 3.1.11-1 and 3.1.13-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Primary Containment Chilled Water System (Unit 2 Only)

To manage aging effects for carbon steel, stainless steel, and copper alloy components exposed internally to the closed cooling water environment, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspection

The closed cooling water chemistry control program is a mitigating activity intended to maintain structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition. The treated water systems piping inspections program supplements the chemistry control program. It is a new program consisting of a one-time inspection to provide direct evidence that the existing chemistry control program is managing aging in piping that is not examined under other inspection programs. The staff's detailed review of these programs may be found in Sections 3.1.2 and 3.1.24 of this SER.

To manage the aging effects of the carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Reactor Building Closed Cooling Water System

To manage aging effects for carbon steel, stainless steel, and copper alloy components exposed internally to the closed cooling water environment, the applicant relies on the following aging management programs:

- closed cooling water chemistry control
- treated water systems piping inspection

The closed cooling water chemistry control program is a mitigating activity that is intended to maintain the structural integrity of plant closed cooling water systems and components by controlling fluid purity and composition. The treated water systems piping inspections program supplements the chemistry control program. It is a new program consisting of a one-time inspection to provide direct evidence that the existing chemistry control program is managing aging in piping that is not examined under other inspection programs. The staff's detailed review of these programs may be found in Sections 3.1.2 and 3.1.24 of this SER.

To manage aging effects for carbon steel bolting exposed to an inside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Reactor Building HVAC System

To manage aging effects for components exposed to an air environment, the applicant relies on the gas systems component inspections program, which is a new, one-time inspection program that visually inspects a sample of components that are considered unlikely to suffer age-related degradation. The staff's detailed review of this program may be found in Section 3.1.25 of this SER.

To manage aging effects for carbon steel bolting exposed to inside and outside environments, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Item 3.1.11-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Refueling Equipment System</u>

To manage aging effects for components exposed to an inside environment, the applicant relies on the following aging management programs:

- protective coatings program
- overhead crane and refueling platform inspection
- structural monitoring program

The protective coatings program provides for periodic inspection of component surfaces. This program also provides for proper corrective actions to prevent significant degradation (e.g., replacement or coating of exposed surfaces). The overhead and refueling platform crane inspection program provides for visual inspection and testing of the reactor building overhead cranes and crane rail supports and refueling platform to assure safe operation of the crane. The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. The staff's detailed review of these programs may be found in Sections 3.1.20, 3.1.10, and 3.1.22 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

<u>Sampling System</u>

To manage aging effects for components exposed to a wetted gas environment, the applicant relies on the gas systems component inspections program, which is a new, one-time inspection program that inspects a sample of stainless steel components from several gas systems within the scope of license renewal to provide evidence that the aging effects predicted for systems with gases as internal environments are being adequately managed. The staff's detailed review of this program may be found in Section 3.1.25 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Tornado Vents System

To manage aging effects for the acrylic components exposed to an inside and outside environment, the applicant relies on the structural monitoring program, which visually inspects structural components on a regular, periodic basis. The staff's detailed review of this program may be found in Section 3.1.22 of this SER.

On the basis of the above information, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Traveling Water Screens/Trash Rack System

To manage aging effects for the carbon and stainless steel components submerged in or exposed to a raw water environment, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The structural monitoring program provides for visual inspection of structural components on a regular, periodic basis. The protective coatings program provides for periodic visual inspections of component external surfaces. This program also provides for proper corrective actions to prevent significant degradation of the traveling water screens and trash rack components due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.22 and 3.1.20 of this SER.

To manage aging effects for carbon steel valve bodies exposed to raw water, the applicant identified the following aging management programs:

- plant service water and residual heat removal service water inspection program
- plant service water and residual heat removal service water chemistry control program
- galvanic susceptibility inspections

The plant service water and residual heat removal service water inspection program is a condition monitoring program designed to detect wall thickness degradation or fouling in the plant service water and residual heat removal service water systems. The plant service water and residual heat removal service water chemistry control program mitigates aging in system piping and components by controlling fluid composition through treatment with sodium hypochlorite and sodium bromide. The aging effects of plant service water system carbon steel components in the river water environment are further managed by the galvanic susceptibility inspections. These are one-time inspections to provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The staff's detailed review of these programs may be found in Sections 3.1.13, 3.1.4, and 3.1.23 of this SER.

To manage aging effects for carbon steel bolting exposed to an outside environment, the applicant relies on the following aging management programs:

- torque activities
- protective coatings program

The applicant's torque activities provide detailed guidance on fastener torque requirements and proper installation methods, thereby preventing loss of preload within non-Class 1 fasteners. Because some fasteners may be susceptible to general corrosion, the protective coatings program provides for periodic inspection of component external surfaces, including fasteners. This program also provides for proper corrective actions to prevent significant degradation of fasteners due to general corrosion (such as replacement or coating of exposed surfaces). The staff's detailed review of these programs may be found in Sections 3.1.11 and 3.1.20 of this SER.

On the basis of the above information, pending satisfactory resolution of Open Items 3.1.11-1 and 3.1.13-1, the staff concludes that the aging management programs identified above are adequate to manage the aging effects associated with the commodity groups in this system.

Summary - Aging Management Programs

The staff has reviewed the information presented by the applicant regarding aging management programs credited for managing the aging effects associated with the commodity groups within the auxiliary systems. On the basis of this information, and upon satisfactory resolution of Open Items 3.1.11-1 and 3.1.13-1, the staff concludes that the applicant has aging management programs which will manage the aging effects for the commodity groups in the auxiliary systems for the period of extended operation.

3.4.4 Conclusion

The staff has reviewed the information for the auxiliary systems in Section 3.2.4, "Auxiliary Systems," Section C.1, "Evaluation of Aging Effects Requiring Management," Section C.2, "Aging Management Reviews," and Section A, "Final Safety Analysis Report Supplement" of the LRA, as supplemented by Section B of submittal dated October 10, 2000. On the basis of this review, pending satisfactory resolution of Open Items 3.1.3-1, 3.1.11-1, 3.1.13-1, and 3.1.18-1, the staff concludes that the applicant has identified the aging effects associated with the auxiliary systems and has demonstrated that the aging effects will be adequately managed so that there is reasonable assurance that these systems will perform their intended functions in accordance with the current licensing basis during the period of extended operation.

3.5 Steam and Power Conversion Systems

3.5.1 Introduction

The applicant described its AMR for the steam and power conversion systems (SPCSs) for license renewal in Sections 3.2.5 "Steam and Power Conversion" of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the SPCSs will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments

are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.5.2 Summary of Technical Information in the Application

The SPCSs included within the AMR scope comprise the electro-hydraulic control (EHC) system and the main condenser system (Unit 2 only).

3.5.2.1 Aging Effects

Electro-Hydraulic Control System

The purpose of the EHC system is to provide control of reactor pressure during reactor startup, power operation, and shutdown. The EHC system also provides a means of controlling main turbine speed and acceleration during turbine startup, and protects the main turbine from undesirable operating conditions by initiating alarms, trips, and runbacks. As described in LRA Section 2.1.2, the initial scoping was performed on the basis of functions. The intended function is associated with the main turbine pressure regulators, whereby the turbine control valve position is controlled by adjusting EHC pressure based on main steam pressure. The EHC regulators that are within the scope of license renewal are 1N11-N042A/B and 2N32-N301A/B. Technical specifications do not require the regulators to be operable; however, transient analysis takes credit for the backup pressure regulator to function to prevent fuel damage in the event of a downscale failure of the inservice regulator.

Materials of construction for the components supporting the EHC intended function are stainless steel piping and stainless steel valve bodies in a reactor water environment. The aging effects associated with this commodity group are loss of material and cracking.

Main Condenser System (Unit 2 Only)

The main condenser provides a heat sink for turbine exhaust steam, turbine bypass steam, and other flows (such as cascading heater drains, air ejector condenser drains, exhaust from the feed pump turbines, gland seal condenser, feedwater heater shell operating vents, and condensate pump suction vents). The main condenser also deaerates and provides storage capacity for the condensate water to be reused. The main condenser system is a two-shell, single-pass, divided water box, deaerating type designed for condenser duty of 5.66 x 10^9 Btu/h, an inlet water temperature of 90 °F, and an average backpressure of 3.5 in. Hg absolute. During plant operation, steam from the last-stage, low-pressure turbine is exhausted directly downward into the condenser shells through exhaust openings in the bottom of the turbine casings. The condenser serves as a heat sink for several other flows, such as exhaust steam from the feed pump turbines, cascading heater drains, air ejector condenser drain, gland-seal condenser drain, feedwater heater shell operating vents, and condensate pump suction vents. Other flows occur periodically. These originate from condensate and reactor feed pump startup vents, reactor feed pump minimum recirculation flow, feedwater lines startup flushing, turbine equipment clean drains, low-point drains, extraction steam spills, makeup, and condensate. During abnormal conditions, the condenser is designed to receive (not simultaneously) turbine bypass steam, feedwater heater high-level dumps, and relief valve discharge from feedwater heater shells, steam-seal regulator, and various steam supply lines.

As described in LRA Section 2.1.2, the initial scoping was performed on the basis of functions. Post-accident radioactive decay holdup is the intended function associated with this system.

The post-accident radioactive decay holdup provides a method for main steam isolation valve (MSIV) leakage control. It uses the main steam drain lines to convey the MSIV leakage during post-accident conditions to the isolated main condenser. The main condenser provides holdup and allows “plate-out” of the fission products that may leak from the closed MSIV during post-accident conditions. MSIV leakage that enters the condenser is ultimately released to the turbine building as non-condensible gases through the low pressure turbine seal after significant plate-out of iodine.

Materials of construction for the components supporting the intended functions of the main condenser are carbon steel for bolting, condenser shell, piping, preheater, strainer, and valve bodies, and stainless steel for piping, preheater, restricting orifices, thermowells, and valve bodies. All components, except bolting, are exposed to a reactor water environment. The aging effects associated with these commodity groups are loss of material and cracking.

3.5.2.2 Aging Management Programs

The LRA identified the following six aging management programs that will manage the aging effects associated with the steam and power conversion systems:

- reactor water chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- flow-accelerated corrosion program
- protective coating program
- torque activities

Detailed descriptions of these aging management programs are included in Section A of the LRA.

Reactor water chemistry control is a major part of the overall chemical control strategy for Plant Hatch. It is a mitigating activity designed to maintain structural integrity of plant systems and components by controlling fluid purity and composition. Treated water systems piping inspections will provide for condition monitoring via one-time examinations intended to provide objective evidence that existing chemistry control is managing aging in piping that is not examined under another inspection program. Galvanic susceptibility inspections will provide for condition monitoring via one-time inspections that will provide objective evidence that galvanic susceptibility is being managed for specific components within the scope of license renewal. The flow-accelerated corrosion (FAC) program is a condition monitoring program designed to monitor pipe wear in those systems that have been determined to be susceptible to FAC-related loss of material. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings in selected components and structures. Torque activities are intended to mitigate loss of preload through use of proper torque techniques.

3.5.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Section 3.2.5 of the LRA to determine whether the applicant has identified the aging effects associated

with the SPCSs, and has demonstrated that the effects of aging on the SPCS will be adequately managed during the period of extended operation.

3.5.3.1 Effects of Aging

The SPCS components are constructed from carbon steel and stainless steel. They are exposed to an external environment of air in the turbine building, which by itself will not cause any significant aging effects. Internally, the SPCS components are exposed to a treated water and/or steam environment. The material degradation effects that were identified in the systems carrying treated water and steam include loss of material, cracking, and loss of preload in bolting. Tables 3.2.5-1 and 3.2.5-2 of the LRA list the components, component functions, materials, environments, applicable aging effects, and the applicable AMPs.

The applicant supplied references to plant-specific and industry-wide experience to support its identification of applicable aging effects for steam and power conversion systems. On the basis of the description of the internal and external environments and materials of fabrication for these systems, the staff concludes that the applicant has identified aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.5.3.2 Aging Management Programs

The applicant has identified six aging management programs for controlling the effects of aging in the SPCSs:

- reactor water chemistry control
- treated water systems piping inspections
- galvanic susceptibility inspections
- flow accelerated corrosion program
- protective coating program
- torque activities

The staff's evaluation of these aging management programs is discussed in Section 3.1 of this SER.

The programs were developed from industry-wide data, industry-developed methodologies, NRC documents, and the applicant's own experience. The applicant concluded that these programs would manage the aging effects in such a way that the functions of the SPCS components will be maintained during the period of extended operation, in a manner that is consistent with the CLB, under all design conditions.

In LRA Tables C.2.2.1-1 and C.2.2.1-2, the applicant lists the following 10 attributes that each aging management program and activity required to address:

- scope of programs, which includes the specific structure, component, or commodity for the identified aging effect

- preventive actions to mitigate or prevent aging degradation

- linkage of parameters monitored or inspected to the degradation of the particular intended function

- description and timely performance of the method used to detect aging effects
- monitoring and trending for timely corrective actions
- acceptance criteria
- corrective actions, including root cause determination and prevention of recurrence
- confirmation process
- administrative controls, which provide a formal review and approval process
- consideration of operating experience from the AMP, including past corrective actions that resulted in program enhancements or additional programs

The staff evaluated the applicant's aging management programs in order to determine if they are adequate to manage the aging of the SPCS components so that the components will perform their intended functions in accordance with the CLB during the period of extended operation. On the basis of the information provided in the LRA and the applicant's responses to the staff's RAIs, pending satisfactory resolution of Open Items 3.1.1-1 and 3.1.11-1 the staff concludes that the aging management programs that the applicant credits for managing the aging effects associated with the SPCS will manage the aging effects such that the SPCS components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.5.4 Conclusions

The staff has reviewed the information in Section 3.2.5 of the LRA. On the basis of this review, pending satisfactory resolution of Open Items 3.1.1-1 and 3.1.11-1, the staff concludes that the applicant has identified the aging effects associated with the SPCS and has demonstrated that aging effects will be adequately managed so that there is a reasonable assurance that the SPCS components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.6 Structures and Structural Components

3.6.1 Introduction

The applicant described its AMR of the structures and structural components for license renewal in the following sections of the LRA: Section 2.4, "Structures Screening Results," Section 3.3.1, "Civil Structural Components," Section A.1, "Existing Programs and Activities," Section A.2, "Enhanced Programs and Activities," Section A.3, "New Programs and Activities," and Section C.2.6, "Aging Management Review for Civil Discipline Commodities." The staff reviewed these sections and appendices of the LRA to determine whether the applicant has demonstrated that the effects of aging on the structures and structural components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2 Summary of Technical Information in the Application

3.6.2.1 Effects of Aging

Section 2.4 of the Plant Hatch LRA provides a list of the various civil/structural component groups that are subject to an aging management review. For each of the civil/structural component groups in Section 2.4 of the LRA, the applicant also provided a general description of the structure or system and intended functions associated with each structure or system. Section C.1 of the LRA describes the applicant's approach toward identifying, categorizing, and evaluating plant environments and materials and the resulting aging effects applicable to systems, structures, and components determined to require aging management reviews. The applicant has adopted a commodities approach to evaluating aging effects requiring management and aging management programs. Section 3.0 of the LRA provides a discussion of the process used to develop the commodity groups. Once systems, structures, and components were divided into commodity groups, an analysis of the aging effects requiring management was performed.

Civil/structural component evaluations are discussed in Section C.2.6 of the LRA , and are based on material of construction.

Environments, aging effects requiring management, and associated aging mechanisms are discussed in Section C.1.4 of of the LRA under each material of construction. Determination of the aging effects requiring management for each of these groups is presented in sections C.1.4.1 through C.1.4.4 of the LRA.

External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

Summaries of aging effects, determined by the applicant as applicable to each of the civil/structural component groups listed in Section 3.6.2.1 of this SER, are provided in Tables 3.3.1-1 through 3.3.1-13 of the LRA.

A brief description of each of the civil/structural component groups and their applicable aging effects is provided in the following sections.

<u>Conduits, Raceways, and Trays</u>

The purpose of the conduits, raceways, and trays system is to provide support for a cable system with cables and penetrations selected, routed, and located to survive the design-basis events established for the plant and to prevent a loss of function of any system due to a cable failure. Additional information may be found in Unit 1 FSAR Section 8.8 and Unit 2 FSAR Section 8.3.

The conduits, raceways, and trays that are mounted according to Seismic Category I criteria are considered safety-related. Seismic Category I conduits, raceways, and trays provide support for essential cable feeding power supplies and controls.

The conduits, raceways, and trays that are neither mounted as Seismic Category I nor Seismic Category II/I are considered non-safety-related. Non safety-related conduits, raceways, and trays provide support for non-essential cable feeding power supplies and controls. Also, some non-seismic raceways are included in safe shutdown pathways.

The applicant identified loss of material as the applicable aging effect for cable trays and supports made of carbon steel.

Control Building

The purpose of the control building is to house the common control room for Units 1 and 2 and associated auxiliaries. The building is a reinforced concrete structure with steel framing, and consists of the following major structural components:

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

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

The control building includes the substructure, foundations, superstructure, walls, floors, and roof necessary to maintain equipment integrity and personnel habitability. The control building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomenon.

The applicable aging effects for structural components in the control building are loss of material and cracking.

Drywell Penetrations

Table 3.3.1-3 of the LRA identifies the containment mechanical penetrations and steel bellows inside vent pipe as components requiring aging management. The function of the containment mechanical penetrations is that of a “fission product barrier,” and that of the bellows is to provide a “pressure boundary and fission product barrier.” Their environment is the inside atmosphere of containment. Table 3.3.1-3 refers to Section C.2.6.2 of the LRA for a description of the aging management review. Mechanical penetrations are discussed in Section 2.4.3 of the LRA.

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

Containment penetrations include electrical penetration assemblies in addition to the mechanical penetrations referenced above. Electrical penetrations are hermetically sealed penetrations, which are welded to the primary containment shell plate. They must maintain their primary

containment pressure integrity function during all postulated operating and accident conditions. They are designed for the same pressure and temperature conditions as the drywell and pressure suppression chamber.

The applicant identified loss of material as the applicable aging effect for drywell penetrations.

Emergency Diesel Generator (EDG) Building

The purpose of the EDG building is to house the emergency diesel generators and their accessories essential for safe plant shutdown for both Unit 1 and Unit 2. The EDG building is a reinforced concrete structure consisting of the following major structural components:

- reinforced concrete foundation mat
- reinforced concrete exterior walls and interior walls
- reinforced concrete roof and parapet wall

The EDG building houses EDGs and their accessories and the building has labyrinth access openings for protection against tornado missiles. The EDG building is designed as a Seismic Category I structure to protect vital equipment and systems both during and following the most severe natural phenomena. The EDG building provides support and equipment integrity for the EDGs, which provide essential ac supply. Additional information may be found in Unit 1 FSAR Section 12.2.6 and Unit 2 FSAR Section 9.4.5.

The applicant identified loss of material as the applicable aging effect for structural components in the EDG building.

Fuel Storage

The fuel storage system provides specially designed underwater storage space for the spent-fuel assemblies, which require shielding during storage and handling. This system also provides specially designed dry, clean storage areas for the new fuel assemblies. The fuel storage facility is located inside the secondary containment on the refueling floor.

The components included in the fuel storage facility are the spent fuel pool, concrete vault and stainless steel liner, fuel pool gates, fuel racks, and other equipment necessary to properly store irradiated fuel and components.

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete, that are exposed to an inside containment environment.

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

The applicant identified loss of material as the applicable aging effect for fuel storage components.

Intake Structure

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

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

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

Unit 1 shares the intake structure with Unit 2. The intake structure has labyrinth access openings for protection against tornado missiles. Additional information may be found in Unit 1 FSAR subsection 12.2.7 and Unit 2 FSAR subsection 3.8.4.

The applicant identified loss of material as the applicable aging effect for structural components in the intake structure.

<u>Main Stack</u>

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

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

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

Unit 1 shares a single main stack used to discharge gaseous waste with Unit 2. The main stack extends 120 meters above ground level. Additional information may be found in Unit 1 FSAR subsection 5.3.4 and Unit 2 FSAR Section 11.3.

The applicant identified loss of material and cracking as the applicable aging effects for structural components of the main stack.

<u>Piping Specialties</u>

The applicant stated that piping specialties provide support for essential piping systems. Essential piping systems are required to maintain the integrity of safety-related and non safety-related systems during normal operations and for transient/accident mitigation. The piping specialties consist of hangers and supports for ASME Class I piping; hangers and supports for non-ASME Class I piping, tubing, and ducts; and tube trays and covers. These piping specialties also include snubbers and pipe restraints, regardless of system affiliation, as well as non-ASME HVAC duct supports and tube trays. The applicant stated that pipe supports for the reactor coolant system and subsystems are provided to ensure pressure retaining capability of the piping systems against weight, seismic, and fluid dynamic loads. Pipe supports maintain the integrity of non safety functions during accident and seismic events. This includes all safety-related plant pipe supports, pipe restraints, and tubing supports. Pipe supports for non safety-related piping (non seismic category) located throughout the plant are included in this function.

These supports are not designed to any seismic criteria. but are designed for dead weight and thermal loads only.

In Table 3.3.1-1 of the LRA, the applicant listed the structural components, environments in which the components are located, materials of construction, applicable aging effects, and aging management programs for the components associated with piping specialties. The piping specialties consist of hangers and supports for ASME Class I piping, hangers and supports for non-ASME Class I piping, tubing, and ducts, as well as cable trays and supports, exposed to containment atmosphere, inside (sheltered), outside, and submerged environments. These components are made of carbon, galvanized, and stainless steels.

Loss of material is identified as the applicable aging effect for piping specialty components.

Primary Containment

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

The primary containment design employs a pressure suppression containment system, which houses the reactor vessel, the reactor coolant recirculating loops, and other branch connections of the reactor primary system. The pressure suppression system consists of a drywell; a pressure suppression chamber (torus), which stores a large volume of water; a connecting vent system between the drywell and the pressure suppression pool, isolation valves, vacuum relief system; containment cooling systems; and other service equipment. The pressure suppression chamber is a steel pressure vessel, in the shape of a torus located below and encircling the drywell, with a major diameter of approximately 107 ft and a cross-sectional diameter of approximately 28 ft. The pressure suppression chamber contains the suppression pool and the air space above the pool. The suppression chamber transmits seismic loading to the reinforced concrete foundation slab of the reactor building. Space is provided outside of the chamber for inspection. Additional information about this system may be found in Unit 1 FSAR subsection 5.1.2 and Unit 2 FSAR subsection.

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

Loss of material and cracking are identified as the applicable aging effects for structural components in the primary containment.

Reactor Building

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

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

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

The reactor building completely encloses the reactor and its pressure suppression primary containment system. Also housed within the reactor building are the core standby cooling systems, reactor water cleanup demineralizer system, standby liquid control system, control rod drive system, reactor protection system, and electrical equipment components. The building is designed for minimum leakage so that the standby gas treatment system (SGTS) has the necessary capacity to reduce and hold the building at a subatmospheric pressure under normal wind conditions. Additional information may be found in Unit 1 FSAR subsection 12.2.1 and Unit 2 FSAR Section 3.0.

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

Loss of material, cracking, material property changes, and loss of adhesion are identified as the applicable aging effects for structural components in the reactor building.

<u>Reactor Building Penetrations</u>

The purpose of the reactor building penetrations is to allow mechanical and electrical equipment and personnel to pass through secondary containment and support the various modes of operation of their associated systems while maintaining the integrity of the secondary containment. The penetrations for piping and ducts are designed for leakage characteristics consistent with containment requirements for the entire building. Electrical cables and instrument leads pass through ducts sealed into the building wall.

Table 3.3.1-7 of the LRA identifies the reactor building penetrations as components requiring aging management. The reactor building penetrations function as a “fission product barrier.” The penetration materials are carbon steel and galvanized steel functioning in inside, outside, and embedded environments. Section C.2.6.3 of the LRA contains the aging management review for steel structures in seismic Category I buildings. Table 3.3.1-7 identifies the protective coating program and the structural monitoring program as the AMPs credited with managing the aging effects for reactor building penetration components. Additional information may be found in Unit 1 FSAR Section 5.3.3.2 and Unit 2 FSAR Figure 8.3-11.

The applicant identified loss of material as the applicable aging effect for reactor building penetration components.

Turbine Building

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

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

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

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

There is no equipment or instrumentation located in the turbine building proper that would preclude the ability to shut down the reactor safely if the turbine building were damaged from a high-energy line failure. The turbine building is designed and constructed to ensure that it will not damage Category I structures or equipment located inside or adjacent to it in the event of a design-basis event (DBE). The cable chase area below Elevation 147 ft is designed to Seismic Category I criteria. The Seismic Category I barrier between the main steam and feedwater piping located above elevation 147 ft and the cable chase area below precludes any adverse direct effects of postulated failure of the main steam or feedwater piping in the turbine building. The cables in this area provide trip inputs for the recirculation pump trip and reactor scram following generator load rejection or a turbine trip originating in the turbine building. Based on these considerations, the portions of the Unit 1 turbine building and the cable chase area below elevation 147 ft are included within the scope of license renewal. The portions of the Unit 2 turbine building and the cable chase area below elevation 147 ft are also in scope, as well as the supports over the radioactive release pathway for the main condenser.

Loss of material is identified as the applicable aging effect for structural components in the turbine building.

Yard Structures

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

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

Additional information about these structures may be found in Unit 1 FSAR Section 5.2.3.9 and Unit 2 FSAR Section 3.8.5.1.

The intended function of the yard structures is to provide equipment integrity and personnel habitability for the various structures listed. This intended function is brought into scope because of the Seismic Category I foundation supporting the liquid nitrogen tank. The liquid nitrogen tank provides the safety-related backup supply of motive gas for the drywell inerting system and the drywell pneumatic system. The FSAR discusses the reliance of the safety analysis upon the liquid nitrogen tank. In addition, Safe Shutdown Pathways 1 and 2 in the fire hazards analysis (FHA) rely upon the liquid nitrogen tank to achieve safe shutdown in the event of a fire.

With respect to the enclosure around the condensate storage tank (CST), the wall and the CST foundation are seismically qualified to Category 1 requirements. The service water valve boxes are in scope as they contain in-scope piping for the plant service water system. The concrete duct runs and pull boxes that traverse the yard between various Class I structures as well as turbine building are included within the scope of AMR. These duct runs are used for routing safety-related circuits and provide protection to them.

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

Loss of material is identified as the applicable aging effect for structural components in yard structures.

3.6.2.2 Aging Management Programs

The program and activity descriptions presented in Sections A and B of the LRA represent the commitments for managing aging of the in-scope systems, structures and components during the period of extended operation. Eleven aging management programs or activities are credited for managing the applicable aging effects for civil/structural components during the renewal term. In many cases, existing programs and activities were found adequate for managing aging in the renewal term. In some cases, aging management reviews revealed that programs or activities required some degree of enhancement to adequately manage aging. Lastly, a number of new inspection programs have been developed by the applicant to provide objective evidence that aging was, in fact, being adequately managed by the credited programs and activities. The scope of these programs and activities for license renewal is discussed in Sections A and B of the LRA.

In Tables 3.3.1-1 through 3.3.1-13 of the LRA, the applicant identified the following aging management programs and activities required to manage aging effects for each of the civil/structural component groups discussed in Section 3.6.2.1 of this SER:

- protective coatings program
- structural monitoring program
- inservice inspection program
- suppression pool chemistry control program
- demineralized water and condensate storage tank chemistry control program
- treated water systems piping inspections
- passive component inspection activities
- gas systems component inspections
- primary containment leakage rate testing program
- component cyclic or transient limit program
- fuel pool chemistry control program

3.6.3 Staff Evaluation

The staff reviewed the information provided in Section 2.4, “Structures Screening Results,” and Section 3.3.1, “Civil/Structural Components,” of the Hatch LRA, and pertinent information provided in Sections A, B, and C of the LRA to determine whether the applicant has adequately identified the effects of aging on the structures and structural components listed in Section 3.6.2.1 of this SER and whether the applicant has demonstrated that the associated components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3). After completing the initial review, the staff issued several requests for additional information that are discussed within the context of the staff evaluation below.

3.6.3.1 Effects of Aging

The applicant stated that the process to determine the aging effects applicable to structural components begins with a review of the aging effects identified in industry literature. Section C.1 of the LRA presented SNC’s systematic evaluation of environments and materials to identify those aging effects requiring management in the renewal term. This evaluation was performed using information developed based on available industry knowledge. A review of pertinent generic industry operating experience, as contained in NRC generic communications, was a part of the applicant’s process for determining aging effects requiring management. Generic communications evaluated as part of this review are listed in Table C.1.5-1 of the LRA and the results are contained in the sections for various material and environment combinations at Plant Hatch. The staff finds this approach for reviewing industry operating experience acceptable.

From this set of aging effects, the applicant considered Plant Hatch materials, operating environment (internal and external) and operating stresses to determine aging effects that need to be managed. Finally, the plant-specific operating experience, industry-wide operating experience and current licensing basis (CLB) are reviewed to identify any additional aging effects that require aging management. The applicant indicated that this process should provide reasonable assurance that the full set of aging effects was established for the aging management review. The staff concurs with this approach for identifying pertinent aging effects.

GENERAL STRUCTURAL AGING EFFECTS

In order to facilitate the identification of aging effects requiring management, the applicant categorized Plant Hatch structural components into the following groups:

- structural steel and aluminum components
- concrete components
- sructural sealants
- acrylic

A discussion of the aging effects requiring management for each of these groups follows.

<u>Structural Steel and Aluminum Components</u>

The applicant grouped structural steel and aluminum components into commodities to efficiently perform the aging management reviews. Details of these reviews are described in Section C.2.6 of the LRA. The component types that make up the commodity groups were collectively reviewed by the applicant. Many of the component types included in these reviews are:

- primary containment steel component types such as the containment shell plate, headers and down comers, penetrations, bellows, bracing, supports, restraints, columns and saddles

- building and structural steel component types such as beams, girders, columns, bracing, hangers, plate, and liner plate

- miscellaneous structural steel and aluminum component types such as door frames, blowout panels, tornado vent support frames, plate, sheet metal, penetrations, pipe, tubing, supports, grating, stairs, handrails, and various miscellaneous shapes

- bolts and anchors, such as structural bolts, cast-in-place bolts, and expansion and wedge anchors

The component types are made from carbon steel, low alloy steel, galvanized steel, stainless steel and aluminum. The process for identifying aging effects considers the materials, operating environments and operating stresses. The service environments are discussed in Section C.1.1 of the LRA. In addition, Sections C.1.2.1 through C.1.2.4 of the LRA further discuss steel in various water environments. Applying the process, the applicant identified the following list of aging effects:

- loss of material due to general corrosion, pitting, crevice corrosion, and MIC
- cracking due to fatigue

Section C.1.4.1 of the LRA discusses these aging effects.

The staff finds the applicant's approach for evaluating the applicable aging effects for structural steel and aluminum components to be reasonable and acceptable. The staff concludes that the applicable aging effects for the component group have been identified.

Concrete Structural Components

The concrete structural components are grouped by the applicant into a commodity to efficiently perform the aging management reviews described in Section C.2.6.1 of the LRA. The following component types that comprise the commodity group:

- masonry block walls
- equipment foundations
- floors, sumps and roofs
- columns, slabs and beams
- interior and exterior walls (above and below grade)

The component types are composed of concrete, reinforcing steel and grout. The process considers the materials, operating environments, and operating stresses. The service environments are discussed in Section C.1.1 of the LRA. Applying the process, the applicant identified the following aging effects:

- loss of material due to corrosion of embedded steel
- cracking in masonry block walls due to expansion or contraction

Section C.1.4.2 of the LRA discusses the above listed aging effects for concrete structural components.

The staff finds the applicant's approach for evaluating the applicable aging effects for concrete structural components to be reasonable and acceptable. The staff concludes that the applicable aging effects for concrete structural components have been identified.

Structural Sealants

The structural sealants are grouped into a commodity by the applicant to efficiently perform the aging management reviews described in Section C.2.6.7 of the LRA. The following sealant types comprise the commodity group and are collectively reviewed:

- joint and caulking sealant in the joints between the exterior precast panels for the reactor buildings

- main control room environmental control system duct gaskets and flex connectors.

The component types are composed of nonmetallic inorganic elastomers, elastomers, and non-asbestos synthetic fibers. The process for identifying the aging effects was applied to structural sealants. The process considers the materials, operating environments and operating stresses. Section C.1.1 of the LRA discusses the service environments. Applying the process, the applicant identified the following list of aging effects:

- material property changes and cracking due to thermal exposure
- loss of adhesion due to exposure to excessive moisture

Section C.1.4.3 of the LRA discusses the above listed aging effects for sealants.

The staff finds the applicant's approach for evaluating the applicable aging effects for structural sealants to be reasonable and acceptable. The staff concludes that the applicable aging effects for structural sealants have been identified.

Acrylic

The tornado vent assembly domes are made of acrylic, and are evaluated in Section C.2.6.8 of the LRA. The acrylic is Plexiglas G cell cast acrylic polymer. The chemical name is polymethyl methacrylate and it is composed of carbon, hydrogen, and oxygen. No fillers are added as part of the forming process and the material contains no significant halogens or sulfur. The process for identifying the aging effects was applied to the acrylic. The process considers the materials and operating environments. The service environments are discussed in Section C.1.1 of the LRA . The applicant identified cracking as the applicable aging effect.

Section C.1.4.4 of the LRA discusses the aging effect.

The staff finds the applicant's approach for evaluating the applicable aging effects for the acrylic tornado vent assembly dome to be reasonable and acceptable. The staff concludes that the applicable aging effects for the tornado vent acrylic dome have been identified.

STRUCTURE AND STRUCTURAL COMPONENT AGING EFFECTS

In order to further facilitate the identification of aging effects requiring management, the applicant evaluated structural components for each structure. A discussion of the aging effects requiring management for each of these structures and structural components follows.

Conduits, Raceways, and Trays

The conduits, raceways, and trays are fabricated from either carbon steel, galvanized steel, or aluminum, exposed to an inside-containment environment. The applicant identified loss of material as the aging effect for carbon steel, and possibly galvanized steel. Loss of material due to general corrosion, crevice corrosion, pitting corrosion and MIC is considered. It was not clear if galvanized steel is included for loss of material. In its response to RAI 3.6-8, dated October 10, 2000, the applicant stated that galvanized steel exposed to an inside containment environment is subjected to an inert nitrogen environment during plant operations. The inerted containment environment reduces the potential for corrosion of galvanized steel products. During outage periods, the environment is conditioned indoor air.

The applicant further stated that Section C.1.4.1 of the LRA discusses loss of material as an aging effect for galvanized steel. For galvanized steel exposed to indoor air, loss of material may occur only in areas where crevices may collect moisture. Therefore, galvanized steel exposed to an inside containment environment can experience loss of material due to crevice corrosion, and crevice corrosion is an aging effect requiring management. The staff finds that the applicant's response is consistent with industry experience and, therefore, is acceptable. This response closes staff RAI 3.6-8. The applicant did not identify any aging effects for aluminum exposed to an inside containment environment. The staff agrees that there are no credible aging effects for aluminum exposed to an inside containment environment.

The applicant also did not consider self-loosening of bolted connections by vibration as an aging effect. The staff understands that proper design and installation practices should minimize the likelihood of bolt self-loosening by vibration. However, expansion and undercut anchors in concrete can become loose due to local degradation of surrounding concrete, as a result of vibratory loads. This concern is addressed and resolved in Section 3.6.3.2 of this SER as part of the closure of RAI 3.6-9, below.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups for conduits, raceways, and trays.

Control Building

The control building contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, aluminum, and reinforced concrete exposed to the embedded, inside, and outside environments. The applicant stated that the aging effect for all of these material and environment combinations is loss of material. The reinforced concrete may also be subject to cracking. The staff agrees with the applicant's position.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity component groups in the control building.

Drywell Penetrations

The drywell penetrations are fabricated from carbon steel that is exposed to the containment atmosphere environment and an embedded environment. The applicant identified loss of material as the aging effect in Table 3.3.1-6 of the LRA. The applicant evaluated the aging effect for this material and environment in Section C.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC.). In Section C.2.6.2, the applicant also identified cracking as an aging effect for drywell penetrations, which is inconsistent with the information supplied in Table 3.3.1-6. However, the applicant states that cracking is caused by fatigue. Management of this aging effect is addressed as a TLAA, and is discussed in Section 4.2 of the LRA. The staff evaluated the TLAA in Section 4.2 of this SER.

As stated before, the applicant has considered loss of material for all containment penetrations and vent line bellows in Table 3.3.1-3 of the LRA. In Section C.2.6.2 of the LRA, the applicant states two aging effects; (1) loss of material due to various types of corrosion, and (2) cracking due to fatigue in the localized areas.

In response to RAI 3.6-36 related to the AMR for penetrations in the torus, the applicant points out that the penetrations are covered under primary containment penetrations in Section C.2.6.2 of the LRA, together with the AMR for drywell penetrations. Many torus penetrations are submerged in torus water, an environment distinctly different from that of the penetrations in the drywell, and they require different ISI, coating, and leak-testing procedures. In a letter dated January 5, 2001, the staff asked the applicant to provide justification why the torus penetrations should not be placed in a commodity group other than that for other components in the primary containment (i.e. drywell). By letter date January 31, 2001, the applicant provided a drawing showing a section through the torus and associated penetrations. The drawing also identified the AMPs associated with the penetrations above and below the water line. For torus penetrations above the water line, the applicant takes credit for implementing the inservice inspection program, the primary containment leakage testing program, the protective coating program, and the component cyclic or transient limit program. Additionally, for torus penetrations below the water line and in the splash zone of the torus shell, the applicant takes credit for implementing the suppression pool chemistry control program and the torus submerged component inspection program. Moreover, the applicant states, “a review of torus inspection reports indicates that degradation of the torus coating, in the form of thinned coatings, and some pitting corrosion in the torus immersion area is general in nature and occurs primarily on the torus shell. No specific corrosion has been noted around penetrations welded to the shell. Corrosion is generally more evident near the torus waterline and at or near the bottom of the torus where sludge or small debris collects.” The applicant also provides a listing of penetrations in the torus of each unit. This information adequately responds to the staff’s concern regarding the AMPs for torus penetrations, and closes RAI 3.6-36. This explanation also provides an acceptable response to the staff’s RAI 3.6-41 related to the separate AMP for torus corrosion, RAI 3.6-41 is also closed.

In response to RAI 3.6-37 related to the specific environment around drywell and torus penetrations, the applicant referred to the programs enumerated in Section C.2 of the LRA as noted in Tables 3.3.1-3 and 3.3.1-6 of the LRA. The staff specifically needs information for the environment (i.e., temperature, humidity, cumulative radiation, demineralized water) around groups of primary containment penetrations having similar operating histories in order to ascertain whether the AMPs are appropriate for the specific operating history/environment for individual groups of containment penetrations. By letter dated January 31, 2001, the applicant

responded that two types of penetrations are considered: electrical and mechanical (piping). Each drywell electrical penetration is composed of the electrical feed-through assembly and the structural piping to which it is attached. Electrical penetrations are included in the EQ program and the electrical, non-metallic assemblies are evaluated and given a qualified life. The structural part of the penetration is managed by the ISI program. The environmental information below can be considered applicable to all drywell penetrations. The worst-case normal inside-containment environment for all drywell penetrations is as follows:

Temperature: 150°F
Radiation: 9.17 E7 Rads (gamma); 4.5 E16 NVT neutron fluence
Humidity: 50% - 90%
Moisture/wetting: None

The environment for torus penetrations varies between the submerged and non-submerged penetrations. The worst-case environment for torus penetrations is as follows:

Temperature: 105°F
Radiation: 1.4 E7 rads gamma
Humidity: 50% - 90%
Moisture/wetting: See visual aid (drawing as discussed above) for submerged penetrations

This information justifies the applicant's focus on the exposure of drywell penetrations to varying environments though they are grouped into the same commodity group. The staff considers RAI 3.6-37 closed.

In response to RAI 3.6-38 related to bellows in the penetrations (other than those in the vent pipes), the applicant referred to the response given to RAI 3.6-37. The staff was basically looking for the operating history of the bellows knowing that the two ply bellows, normally used in containments, undergo gradual degradations and leakage. However, in response to RAI 3.6-42, the applicant provided the following information. The applicant indicated that, upon the receipt of IN 92-20, "Inadequate Local Leak Rate Testing," it decided to select a sample of three bellows for augmented testing to evaluate the adequacy of local leak rate testing (LLRT) methods and procedures. A plate was welded inside containment to test the bellows in the proper direction. The tests confirmed that the testing methods and procedures were acceptable. Some of the two-ply bellows in Unit 2 were replaced because of bellow leakage detected during the LLRT. The bellows leakage was caused by the inadvertent exposure of the bellows to chloride during maintenance activities. This description confirms that the applicant has adequately considered the potential aging effects for monitoring leakage in primary containment bellows. RAIs 3.6-38 and 3.6-42 are considered closed.

On the basis of the above information, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with the drywell penetrations.

EDG Building

The EDG building contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, and concrete exposed to the embedded, inside, and outside environments. The aging effect for all of these material and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the EDG building.

Fuel Storage

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete exposed to an inside environment. The applicant identified loss of material as the aging effect for all components made of these materials, except for the aluminum storage racks, exposed to an inside environment. The applicant stated that an inside environment is a “sheltered” environment, which assumes 50% to 90% humidity, an ambient temperature less than 120°F and a maximum radiation level of 9.0 X 10^6 rads. The applicable aging effect due to exposure to an inside environment is loss of material due to general corrosion, crevice corrosion, pitting, and MIC of carbon steel and submerged stainless steel components.

For components fabricated from stainless steel or aluminum in a demineralized water environment, the applicant identified loss of material as the aging effect in Table 3.3.1-4 of the LRA. The demineralized water is processed on site and is stored in demineralized water storage tanks and condensate storage tanks where impurities and conductivity are maintained at low levels but dissolved oxygen concentrations are neither controlled nor monitored. The applicant stated that the applicable aging effect due to exposure to a demineralized water environment is loss of material due to crevice corrosion, pitting and MIC.

According to Table 3.3.1-4, loss of material is an applicable aging effect for stainless steel components in an embedded environment. The fuel pool chemistry control program is the AMP credited with managing this aging effect

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with fuel storage.

Intake Structure

The intake structure contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, and concrete exposed to embedded, inside, outside, high humidity, and wetting-other-than-humidity environments. The aging effects for all of these materials and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the intake structure.

Main Stack

The main stack contains various components (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, aluminum and concrete exposed to the inside and outside environments. The aging effect for all of these materials and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the main stack.

Piping Specialties

For the piping specialties, the applicant stated that hangers and supports for ASME Class I piping (made of carbon steel and galvanized steel) are exposed to a containment atmosphere or inside (sheltered) environment. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.4 of the LRA, loss of material is identified as an applicable aging effect. The applicant also stated that hangers and supports for non-ASME Class I piping, tubing, and ducts (made of carbon, galvanized, and stainless steels) are exposed to a containment atmosphere, inside (sheltered), outside, or submerged environment. As discussed in Sections C.1.2.2, C.1.2.8, C1.2.9, and C.2.6.4 of the LRA, loss of material is identified as an applicable aging effect.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with piping specialties.

Primary Containment

The applicant stated that the primary containment system contains various components (e.g., bolts and anchors, containment penetrations, miscellaneous steel) fabricated from carbon steel, galvanized steel, and stainless steel exposed to the containment atmosphere. The applicant identified loss of material as the aging effect. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.2 and C.2.2.3.1 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC).

The applicant identified loss of material and cracking as the aging effects. According to Table 3.3.1-3 of the LRA, the primary containment system contains various components (e.g., bolts and anchors, blind flange, containment isolation valves, miscellaneous steel) fabricated from carbon steel, possibly galvanized steel, and stainless steel exposed to torus water. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.1 and C.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, galvanic corrosion, pitting, MIC, and erosion corrosion). RAI 3.6-14 requested the applicant to clarify whether any primary containment galvanized steel components are subject to the torus water environment and, as applicable, indicate the appropriate AMP. The applicant indicated that some galvanized carbon steel grating components that are part of the platforms inside the torus may be intermittently exposed to torus water at some time during operation if the torus water level rises high enough, or if sloshing of the water surface occurs during a safety relief valve (SRV) discharge. The applicant stated that galvanized carbon steel exposed to water may experience a loss of material due to corrosion, and corrosion of galvanized steel components inside the torus is managed by the protective coatings program and by suppression pool chemistry control, as discussed in LRA Section C.2.6.2. This response is sufficient in detail and acceptable. RAI 3.6-14 is considered resolved.

The primary containment system also contains various components (e.g., containment isolation valves, containment penetrations, miscellaneous steel) fabricated from carbon steel and stainless steel exposed to demineralized water. The applicant identified loss of material as the aging effect. The applicant evaluated the aging effects for these materials and environment in Sections C.2.2.2.2 and C.2.2.3.1 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC). SNC also identified cracking as an aging effect caused by thermal fatigue.

The primary containment system contains containment isolation valves and piping fabricated from carbon steel exposed to raw water. The applicant identified loss of material and cracking as the aging effects. The applicant evaluated the aging effects for this material and environment in Section C.2.2.6.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., crevice corrosion, pitting, MIC, and fouling). Section C.2.2.6.2 also identified cracking caused by thermal fatigue and flow blockage caused by fouling as aging effects for these components and this environment.

The primary containment system contains various components (e.g., anchors and bolts, containment penetrations, miscellaneous steel) fabricated from carbon steel and possibly galvanized steel and stainless steel that is embedded. RAI 3.6-18 requested the applicant to clearly indicate the materials that are embedded. The applicant, after its review of screening records and supporting information, identified that only carbon steel components that are listed in Table 3.3.1-3 as embedded are the ones that are embedded items. RAI 3.6-18 is closed.

Staff RAI 3.6-19 requested the applicant to clarify a potential discrepancy between Table 3.3.1-3 and Section C.2.6.2 of the LRA. The applicant stated that cracking identified as a detrimental aging effect in Section C.2.6.2 applies only to cracking due to fatigue of the torus. The applicant further asserted that anchors and bolts, and miscellaneous steel are not subjected to significant vibratory or cyclic loads, and are therefore not subject to cracking. Also, stainless steel bellows, used in some penetrations that are subject to thermal movement or longitudinal operational piping loadings, are designed to withstand the thermal and cyclic loadings to which they are subjected, and are not considered susceptible to cracking. This response resolves RAI 3.6-19. The applicant evaluated the aging effects for these materials and environment in Section C.2.6.2 and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting, and MIC).

The primary containment system contains containment isolation valves, tubing, and piping fabricated from carbon steel and stainless steel exposed to wetted gas. The applicant identified loss of material and cracking as the aging effects. The applicant evaluated the aging effects for this material and environment in Sections C.2.2.9.1 and C.2.2.9.2 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, pitting, crevice corrosion, galvanic corrosion, and MIC). Section C.2.2.9.1 also identified cracking caused by thermal fatigue as an aging effect for these components and this environment.

In Table 3.3.1-3, the applicant identified fatigue cracking for blind flanges (commodity group C.2.2.3.1), containment isolation valves (commodity groups C.2.2.2.2 and C.2.2.3.1, C.2.2.6.2, and C.2.2.9.2), piping (commodity groups C.2.2.2.2, C.2.2.3.1, C.2.6.2, C.2.2.9.1), tubing (commodity group C.2.2.9.2) and vent pipes, vent headers and downcomers (commodity group C.2.6.2). In Section 4 of the LRA, the applicant included thermal fatigue as a TLAA (the staff's evaluation of this TLAA is discussed in Section 4 of this SER).

Based on the staff's experience, degradation of piping systems (e.g., loss of integrity of bolted closures, cracking of welds and loosening bolts) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In Table 3.3.1-3, the applicant did not identify loss of preload as an aging effect for bolting in the primary containment system. The applicant was requested via RAI 3.6-50 to clarify whether the vibration related aging effects including cracking of piping welds and loosening of bolts were considered in the aging review for the primary containment system, and if they were excluded, provide the basis. The applicant responded to this RAI in its letter dated October 10, 2000. The applicant stated that the loss of preload in bolted connections of primary containment piping was inadvertently omitted from Table 3.3.1-3.

The applicant further stated that it has revised the table to include the aging effect of loss of preload by an electronic communication dated June 20, 2000. The staff finds the applicant's response acceptable and RAI 3.6-50 is closed.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the primary containment.

Reactor Building

The reactor building contains various components (e.g., anchors and bolts, blowout panels, miscellaneous steel, reinforced concrete, and structural steel) fabricated from either carbon steel, aluminum, stainless steel, elastomers, concrete, and masonry block exposed to an inside and outside environment. The applicant evaluated the aging effects for these materials and environments in Sections C.2.6.1, C.2.6.3, C.2.6.6, and C.2.6.7 of the LRA and identified several aging effects. These include loss of material, material property changes and cracking of elastomers, and cracking of concrete and masonry block.

For the reactor building, the applicant stated that carbon steel anchors and bolts are exposed to inside (sheltered) and outside environments. As is discussed in Sections C.1.2.8, C.1.2.9 and C.2.6.3 of the LRA, loss of material is identified by the applicant as an applicable aging effect. The applicant stated that carbon and galvanized miscellaneous steels, as well as structural steels made of carbon, galvanized, and stainless steel are exposed to inside (sheltered), outside and submerged environments. As discussed in Sections C.1.2.2, C.1.2.8, C.1.2.9 and C.2.6.3 of the LRA, loss of material is an applicable aging effect for these structural components. The applicant stated that panel joint seals and sealants made of elastomers (nonmetallic and inorganic) are exposed to inside (sheltered) and outside environments. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.7 of the LRA, material property changes, cracking, and loss of adhesion are listed by the applicant as applicable aging effects. The applicant also stated that reinforced concrete structures and components serving functions including structural support, fire barrier, flood barrier, fission product/missile barriers, component shelter/protection, radiation shielding and non-safety-related structural support are made of concrete or masonry blocks and carbon steel reinforcement. These structures and components are exposed to an inside (sheltered) and an outside environment. As discussed in Sections C.1.2.8, C.1.2.9, and C.2.6.1 of the LRA, loss of material and cracking are applicable aging effects for these structural components.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the reactor building.

Reactor Building Penetrations

The applicant indicated that the reactor building penetrations are fabricated from carbon steel and galvanized steel that is exposed to the inside and outside environment and an embedded environment. The applicant identified loss of material as the aging effect in Table 3.3.1-7 of the LRA. The applicant evaluated the aging effects for these materials and environment in Section C.2.6.3 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting and MIC).

Table 3.3.1-7 indicates that the aging effects of reactor building (RB) penetrations are managed by the structural monitoring program (SMP) and the protective coating program. However, Section A.2.5 of the LRA does not specifically list reactor building penetrations as part of the

SMP. In RAI 3.6-39, the staff requested the applicant to clarify if the RB penetrations are covered under the SMP, or provide information as to where the aging effects of reactor building penetrations are covered. In response to this request, the applicant stated that reactor building penetrations are included in the SMP. SNC further indicated that Section C.2.6.3 of the LRA, which discusses steel as a commodity group, also explicitly identifies T-54 reactor building penetrations as included in the commodity and SMP is listed among the AMPs applicable to the reactor building penetrations. The applicant's response resolves the staff concern and the issue is closed.

In response to RAI 3.6-39 related to the aging effects for reactor building penetration seals and gaskets and their inclusion of leak-tightness characteristics, the applicant stated that the secondary containment (including reactor building penetrations) is not designed to be leak-tight. Rather, it has controlled leakage characteristics, and is maintained at a negative pressure relative to the outside, so that the air flow is into the building. These characteristics are confirmed periodically by secondary containment leakage tests. The applicant further stated that, in order to manage aging of the reactor building penetrations, aging effects associated with the penetrations are managed prior to such a gross determination of degradation. The relevant AMRs have identified these "first line" aging effects requiring management in the renewal term. Reactor building penetrations are discussed in LRA Tables 3.2.4-18, 3.3.1-7 (described as structural steel), and 3.4.1-1 (as Nelson frames). AMRs are presented in LRA Sections C.2.3.4.1 (for fire penetration seals), C.2.6.3 (for reactor building penetrations structural steel), and C.2.5.2 (for Nelson frames). The AMR for the neoprene rubber inserts in Nelson Frames determined that there were no aging effects requiring management.

The response to RAI 3.6-39 indicates that to serve as a fission product barrier, the reactor building penetrations should have an AMP related to the reactor building penetrations' leak-tightness. A review of the Plant Hatch Technical Specifications (TS Section B 3.6.4.1) indicates that the limiting condition for operation, its applicability, and action and surveillance requirements for secondary containment provide adequate assurance that the leak-tightness characteristics of these penetrations will be monitored and maintained periodically during the period of extended operation. By letter dated January 5, 2001, the staff asked the applicant to provide justification as to why the TS requirements should not be included as part of the total aging management program for reactor building penetrations.

By letter dated January 31, 2001, the applicant stated that numerous penetrations are considered to be secondary containment penetrations. The principal types of penetrations are mechanical (for piping), electrical (for conduits and cable trays) and HVAC (for HVAC ducts). Mechanical penetrations are of all-welded construction, and have no seals or gaskets (see LRA, Table 3.3.1-7). Also, there are no seals and gaskets in HVAC ducts credited for maintaining secondary containment. Fire penetration seals located in fire barrier penetrations are managed by fire protection activities as shown in LRA Table 3.2.4-18. The penetrations for electrical conduits and cable trays consist of Nelson frames. There are no aging effects for the polymers and the steel of the Nelson Frames per LRA Table 3.4.1-1.

Moreover, the applicant states that any contribution of reactor building penetrations to secondary containment in-leakage is thus, extremely small. In addition, even if a mechanism were postulated that would result in degradation of penetrations leading to secondary containment in-leakage, the Plant Hatch Technical Specification Surveillance Requirements for secondary containment do not provide a useful tool for license renewal due to the relative magnitude of postulated reactor building penetration in-leakage as compared with other, dominant pathways.

Additionally, the applicant states that other secondary containment in-leakage pathways include reactor building doors and caulked joints associated with the reactor building walls. Reactor building doors are not part of the reactor building penetrations.

By letter dated January 31, 2001, the applicant referenced a telephone conference on January 26, 2001, in which the overall drawdown characteristics of the reactor building were discussed. The applicant pointed out that outside and apart from license renewal, as part of the numerous performance-based tests that are routinely performed by Plant Hatch as part of the Technical Specifications, a periodic test is performed which identifies the drawdown characteristics of the secondary containment. However, for license renewal, the applicant observes that aging degradation of each in-leakage pathway contributor is managed by programs credited in the LRA to maintain intended function. The various applicable sections of the LRA are noted in the above paragraphs.

The response above does not address the staff's concern about managing the controlled leakage characteristics of the secondary containment system (including its penetrations). In Section 2.4.6 of the LRA, the intended function of the reactor building penetrations (T54-01) is "maintain secondary containment leakage rates within design limits." In TS Section B 3.6.4.1, under "LCO," it is states "For the secondary containment to be OPERABLE, it must have adequate leak tightness to ensure that the required (0.2 inch) vacuum can be established and maintained." Numerous penetrations associated with the reactor building could contribute towards violating the design limits established for secondary containment (i.e., reactor building). Thus, the applicant should have an AMP to demonstrate that the overall effect of numerous degradations has not violated the leakage characteristics of the reactor building. This is Open Item 3.6.3.1-1.

In response to RAI 3.6-40, related to the benchmarking of the reactor building penetration coating, the applicant stated, "A baseline inspection program will be done for the penetrations prior to the start of the renewal period. The periodicity of future inspections will be determined by a plant coating specialist based on the findings of the initial inspection." The staff finds this response adequate and RAI 3.6-40 is closed.

On the basis of the above discussion, and pending satisfactory resolution of the Open Item 3.6.3.1-1, the staff finds that the applicant has identified all applicable aging effects for the commodity groups associated with the reactor building penetrations.

<u>Turbine Building</u>

The applicant stated that the turbine building has components that are fabricated from carbon steel and galvanized steel (e.g., anchors and bolts, miscellaneous steel, reinforced concrete, and structural steel) that are exposed to the inside, outside, wetting-other-than-humidity, buried, and embedded environments. The applicant identified loss of material as the aging effect in Table 3.3.1-8 of the LRA. The applicant evaluated the aging effects for these materials and environment in Sections C.2.6.1 and C.2.6.3 of the LRA and identified several forms of corrosion that may result in loss of material (e.g., general corrosion, crevice corrosion, pitting and MIC.). The applicant identified cracking as an aging effect for concrete and masonry block walls in Section C.2.6.1, but did not identify cracking as an aging effect in Table 3.3.1-8. In RAI 3.6-52, the staff requested SNC to clarify this discrepancy. In its January 31, 2001 response to the request, the applicant stated that there are masonry block walls in the turbine building, but none of these are in close proximity to, or have attachments from, safety related piping or equipment, and hence do not perform an intended function and are not in scope. Additionally, during a

December 2000 meeting, the staff requested that SNC address whether any block walls within the scope of A-46 evaluations are in the turbine buildings. SNC responded that there were no A-46 block walls in the turbine buildings. The above SNC responses resolve the staff concerns and the issues are judged as closed.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the turbine building.

Yard Structures

The yard structures contain various components (e.g., anchors and bolts, cover plates, pool boxes, miscellaneous steel, reinforced concrete, and structural steel) fabricated from carbon steel, galvanized steel, aluminum and concrete exposed to inside and outside environments. The applicant stated that the aging effects for all of these material and environment combinations is loss of material.

On the basis of the above discussion, the staff finds that the applicant has identified all applicable aging effects for the commodity groups in the yard structures.

3.6.3.2 Aging Management Programs

Once the set of aging effects requiring management was identified for a particular commodity group, a list of aging management programs credited for managing aging of structures or components within the commodity group was produced. This list was compiled by examining the aspects of current programs in plant procedures and program documents. The staff concurs with this approach to identifying applicable aging management programs.

A discussion of the aging management programs credited for managing the aging effects for commodity groups in structures and structural components follows.

Conduits, Raceways, and Trays

To manage corrosion-induced aging effects for carbon steel components and galvanized steel components that show signs of rust, exposed to an inside containment environment in the conduits, raceways, and trays, the applicant relies on the following aging management programs:

- structural monitoring program
- protective coatings program

The structural monitoring program (SMP) provides condition monitoring and appraisal of certain structures, including the conduits, raceways, and trays. The structural monitoring program is discussed in detail in Section 3.1.22 of this SER. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance, and inspection of protective coatings on selected components and structures. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

In Table 3.3.1-2 of the LRA, the applicant identified loss of material due to corrosion of carbon steel and galvanized steel as a plausible aging effect. The applicant also discussed aging effects

for the loss of materials in Section C.2.6.4 of the LRA and took credit for the SMP and the protective coatings program as applicable AMPs. However, the applicant did not identify self-loosening of bolted connections due to vibration as an aging effect. The staff believes that expansion and undercut anchors in concrete may become loose due to local degradation of the surrounding concrete as a result of vibratory loads. RAI 3.6-9 requested the applicant to provide the technical justification for not identifying loss of preload due to the effects of vibration on concrete surrounding expansion and undercut anchors.

In its letter dated October 10, 2000, the applicant stated that structural supports, including hangers and cable trays, are passive structural components that are rarely subjected to high displacement vibration loading, or high stress vibration loading. Cable trays are isolated from rotating equipment or active equipment by the use of flexible conduits or cables. No gaskets are used in structural connections. For structural joints installed with proper torque, the initial loss of preload is limited, and sufficient preload remains to assure joint integrity. The applicant further stated that structural bolts and anchors at Plant Hatch were installed and inspected per vendor recommendations and in accordance with plant procedures. Per Electric Power Research Institute (EPRI) Bolting Procedures Reference Manual, NP5067, Vol. 1, “A Reference Manual for Nuclear Power Plant Maintenance Personnel, Large Bolt Manual,” loss of preload over an extended period requires elevated temperatures, stress levels in proximity to the material yield stress, and cyclic loading. Structural supports, hangers, bolts and anchors are not subject to high temperatures, high displacement vibration loading, or high stress vibration loading. The applicant also indicated that a review of the plant operating history for the last 5 years did not identify any deficiencies resulting from loss of anchor or bolt preload and loss of preload in structural joints has not been identified as a widespread industry problem. Therefore, the Plant Hatch aging management review concluded that loss of preload due to vibratory loads is not an aging effect requiring management for bolts or anchors used by structural supports, hangers or cable trays.

Additionally, the applicant stated that Class 1 seismic structures at Plant Hatch are designed in accordance with American Concrete Institute (ACI) 318-63, “Building Code Requirements for Reinforced Concrete.” EPRI Report TR-103842, “Class 1 Structures Industry Report,” Revision 1, dated July 1994, evaluated the effect of cyclic loads on concrete structures. The report concluded that cycle loading (fatigue) would not cause significant degradation of concrete structures designed in accordance with ACI 318. The design stress level is limited to less than 50% of the static strength, and the structures can resist extremely high cycles of loading in the low amplitude, low stress range, and actual stresses from any high cycle loading on concrete structures, such as those from machine vibration, are a small portion of the combined stresses resulting from static and dynamic loads. A review of the plant operating history for the last 5 years did not identify any deficiencies resulting from loss of anchor bolt, expansion bolt, or undercut anchor preload. Therefore, the aging management review concluded that local degradation of the concrete surrounding anchors, because of vibratory loads, is not an aging effect requiring management, and would not cause loss of preload for support anchors.

The staff reviewed the above justification provided by the applicant, including Plant Hatch’s past 5 years of operating experience, and concurs with the above findings. RAI 3.6-9 is closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with conduits, raceways, and trays will be adequately managed by the above listed AMPs.

Control Building

To manage corrosion-induced effects of aging for components fabricated from carbon steel, galvanized steel, aluminum, and concrete exposed to inside and outside environments in the control building, the applicant relies on the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the control building. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the control building will be adequately managed by the above listed AMPs.

Drywell Penetrations

Aging management programs determined by the applicant to manage aging effects requiring management for drywell penetrations are:

- protective coatings program
- inservice inspection program (ISI Program)
- primary containment leak rate testing program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The ISI Program provides for visual inspections of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Primary containment leak rate testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections are conducted in accordance with 10 CFR Part 50, Appendix J.

The staff's detailed review of these programs may be found in Sections 3.1.9, 3.1.14, and 3.1.20 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with the drywell penetrations will be adequately managed by the above listed AMPs.

EDG Building

To manage corrosion induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to inside and outside environments in the EDG building, the applicant identified the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the EDG Building. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the EDG building will be adequately managed by the above listed AMPs.

Fuel Storage

To manage corrosion-induced aging effects for carbon steel, stainless steel, and concrete components exposed to an inside environment in the fuel storage areas the applicant relies on:

- structural monitoring program
- protective coatings program

The structural monitoring program provides condition monitoring and appraisal of certain structures, including those associated with fuel storage. The protective coatings program provides a means of preventing or minimizing aging effects that would otherwise result from contact of the base metal with the associated environment. It is a mitigation and condition monitoring program designed to provide base metal aging management through application, maintenance and inspection of protective coatings on selected components and structures. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

To manage the corrosion-induced aging effects for stainless steel and aluminum components exposed to a demineralized water environment, the applicant relies on the fuel pool chemistry control program. This program is intended to mitigate aging in the fuel pool liner and associated components by controlling fluid purity and composition. The related activities are discussed in detail in Section 3.1.5 of the SER.

Table 3.3.1-4 of the LRA identifies loss of material as an aging effect for the aluminum restraints in the spent fuel pool (SFP) demineralized water. The applicant discussed the loss of material due to galvanic corrosion, crevice corrosion, pitting, and MIC in LRA Section C.2.6.6 and took credit for fuel pool chemistry control as an AMP; however, Table 3.3.1-4 and Section C.2.6.6 indicate that the aluminum racks do not require an AMP. RAI 3.6-20 asked SNC to explain the discrepancy. SNC stated that the aluminum racks, described as storage racks in LRA Table 3.3.1-4, are located in the new fuel storage vault. These aluminum racks are exposed to air only.

There are no aging effects requiring management for aluminum exposed to air. A revised six-column table to re-label the new fuel racks is included in the response to RAI 3.6-24. The staff finds this justification adequate and acceptable. Thus, RAI 3.6-20 is closed.

Section C.2.6.5 of the LRA stated that the applicant regularly checks SFP chemistry control activities under the fuel pool chemistry control program. RAI 3.6-21 requested the applicant to explain how this program manages cracking of stainless steel components (e.g., liner plate). To determine whether these inspections help to ensure that cracking does not occur, the staff needs to know whether these inspections check for cracking, the techniques used, and how many times such inspections of the spent fuel system stainless steel components have been performed to date. Additionally, the staff noted that Table 3.3.1-4 does not list cracking of spent fuel pool stainless steel liners as an aging effect under the structural steel category. Therefore, RAI 3.6-31 asked the applicant to justify its exclusion of this aging effect from Table 3.3.1-4, or provide a plant-specific discussion of the aging effect and the appropriate AMP for managing the cracking of spent fuel pool stainless steel liners. SNC stated that the water in the pool is demineralized water. Operating temperature data in the spent fuel pools was reviewed by the applicant, and the maximum recorded pool temperature did not exceed 115 °F. This temperature is less than the 140° F threshold established in Section C.1.2.2.2 of the LRA for SCC, regardless of the dissolved oxygen content. Therefore, SCC for the spent fuel pool stainless steel liners and other stainless steel components is not an aging effect requiring management. The staff finds the applicant’s justification acceptable and RAIs 3.6-21 and 3.6-31 are closed. The staff reviewed the fuel pool chemistry control program in Section 3.1.5 of this SER.

The fuel storage system contains components fabricated from carbon steel, stainless steel, aluminum, and concrete exposed to an inside environment. Table 3.3.1-4 of the LRA does not clearly identify the environments for which the listed aging effects are managed by the corresponding AMPs. RAI 3.6-23 requested SNC to clarify the environments for which the listed aging effect occurs and the AMP that manages the aging effect. Furthermore, according to Table 3.3.1-4, loss of material is an applicable aging effect for stainless steel components in an embedded environment. However, based on the information in the same table, there is no applicable AMP or activity identified. RAI 3.6-24 asked the applicant to specify the applicable AMP to manage loss of material for stainless steel components in an embedded environment or provide the basis for concluding that an AMP is not required. In its response, SNC revised Table 3.3.1-4 to achieve needed clarity. The staff finds the applicant’s table revision reasonable and RAIs 3.6-23 and 3.6-24 are considered closed.

Bolts, which are used in safety-related and non-safety-related structural support, are fuel storage system components in the anchors and bolts (C.2.6.5) commodity group, and these bolts are susceptible to a loss of pre-load (due to embedment, gasket creep, thermal effects, and self-loosening). RAIs 3.6-25 and 3.6-28 requested SNC to provide the basis for not including this aging effect. The applicant resolved this RAI based on justifications provided in its response to staff RAI 3.6-9 included in its letter to the staff dated October 10, 2000. RAIs 3.6-25 and 3.6-28 are closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with fuel storage will be adequately managed by the above listed AMPs.

Intake Structure

To manage corrosion induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to the inside and outside environments in the intake structure, the applicant designated the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions to prevent significant degradation of these components due to loss of material (such as replacement or coating of exposed surfaces). The structural monitoring program provides condition monitoring and appraisal of certain structures, including the intake structure. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

RAI 3.6-34 asked if Plant Hatch has any earthen embankments as part of its ultimate heat sink system or intake structure and asked SNC to discuss, as applicable, the aging effects of these structures due to loss of material from erosion and cracking due to settlement. SNC stated that there is no earthen embankment included as part of the Plant Hatch ultimate heat sink. The river intake structure is located on the south bank of the Altamaha River. It is flanked by a circular steel sheet pile cell on each side near the front of the structure. The main river channel, where the water speeds are greatest, is located closer to the north bank of the river. Erosion has not been a problem on the south bank of the river near the intake structure. Settlement of the intake structure has been monitored since construction. Settlement has been within predicted values, and has leveled off. Therefore, erosion of the soil at the intake structure, and cracking due to settlement or differential settlement are not considered to be aging effects requiring management for the intake structure. This response is sufficient to resolve RAI 3.6-34.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the intake structure will be adequately managed by the above listed AMPs.

Main Stack

To manage corrosion-induced effects of aging for components fabricated from carbon steel, galvanized steel, and concrete exposed to inside and outside environments in the main stack, the applicant relies on the following aging management programs:

- protective coatings program
- structural monitoring program

Because some of these components may be susceptible to loss of material, the protective coatings program provides for periodic inspection of component external surfaces. This program will also provide for proper corrective actions (such as replacement or coating of exposed surfaces) to prevent significant degradation of these components due to loss of material. The structural monitoring program provides condition monitoring and appraisal of certain structures, including the main stack. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the main stack will be adequately managed by the above listed AMPs.

Piping Specialties

To manage aging effects for hangers and supports for ASME Class I piping, and hangers and supports for non-ASME Class I piping, tubing, and ducts, made of carbon, galvanized, and stainless steels, that are exposed to containment atmosphere, inside (sheltered), outside, and submerged environments associated with piping specialties, the applicant identified the following aging management programs for managing the aging effects:

- protective coatings program
- structural monitoring program

The applicant cited the above programs to manage loss of material for the structural components exposed to the described environments. The staff has verified that these two programs are included in Section C.2.6.4 of the LRA as applicable aging management programs. The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with piping specialties will be adequately managed by the above listed AMPs.

Primary Containment

AMPs determined by the applicant to manage aging effects requiring management in the primary containment are:

- protective coatings program
- ISI program
- suppression pool chemistry control
- primary containment leak rate testing program
- demineralized water and condensate storage tank chemistry control
- treated water systems piping inspections
- gas systems component inspections
- passive component inspection activities
- structural monitoring program
- component cyclic or transient limit program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated service level I coatings (service level I coatings are used in areas inside the reactor containment where coating failure could adversely affect the operation of post-accident fluid systems and thereby impair safe shutdown). This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The ISI Program provides for visual inspection of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

Suppression pool chemistry control limits detrimental impurities and conductivity within the suppression pool and thereby mitigates aging. Suppression pool chemistry control implements the EPRI guidance on BWR water chemistry for auxiliary systems.

Primary containment leak rate testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections and testing are conducted in accordance with 10 CFR Part 50, Appendix J.

Demineralized water and condensate storage tank chemistry control serve to mitigate loss of material due to pitting, crevice corrosion, or MIC by limiting concentrations of detrimental impurities and conductivity. Demineralized water quality is monitored on a weekly basis and corrective actions are taken in the event that any limits are exceeded.

Demineralized water and condensate storage tank chemistry control implement EPRI BWR water chemistry guidelines.

The treated water systems piping inspections serve to validate the adequacy of demineralized water and condensate storage tank chemistry control in mitigating loss of material within stainless steels by performing appropriate examinations of a sample population of the susceptible locations.

Aging effects due to corrosion will be detected for these components through gas systems component inspections. This activity will involve appropriate inspections of a representative sample of the most likely degradation locations.

The passive component inspection activities serve to validate the adequacy of the drywell floor and equipment sump discharge piping sections to perform a primary containment function by performing inspections, similar to VT-1, of component internal surfaces any time an applicable component is opened for periodic maintenance or repair. This information is evaluated and trended to provide adequate assurance that any significant aging trends are identified and corrected.

The structural monitoring program (SMP) inspection process assesses the ongoing overall conditions of structures and identifies any ongoing degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

Management of cracking due to fatigue of the torus is implemented via a component cyclic or transient limit program. The component cyclic or transient limit program is designed to track cyclic and transient occurrences, including the limiting location for the torus, to ensure that reactor coolant pressure boundary components will remain within the ASME Code Section III limits.

The staff's detailed review of these programs may be found in Sections 3.1.6, 3.1.7, 3.1.9, 3.1.12, 3.1.14, 3.1.20, 3.1.22, 3.1.24, 3.1.25, and 3.1.27 of this SER.

In response to RAI 3.6-41 related to torus corrosion, the applicant provided a description of torus degradation found in both Plant Hatch units. However, the applicant emphasized that, in spite of the degradation, the actual shell thicknesses are well above the required minimum shell thicknesses. The applicant stated that it plans to continue to perform desludging, visual examination, and spot coating repairs periodically, based on the history of past inspection. The staff believes that operating experience at Plant Hatch and other industry operating experience related to torus corrosion indicates a need for a program to manage torus corrosion during the period of extended operation. SNC is requested to provide justification as to why this program should not be a separate program in the LRA. This is Open Item 3.6.3.2-1.

Section C.2.6.2 of the LRA stated that the ISI program provides for visual inspection of the internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. 10 CFR 50.55a endorsed the ASME Section XI, Subsection IWE Code with the condition that 10 CFR 50.55a(b)(2)(ix) provisions be complied with. The LRA is not clear regarding this requirement. RAI 3.6-11 asked SNC to confirm that both the scope and the detail of the inspection implemented in accordance with ASME Section XI Table IWE-2500-1 also comply with the requirements for 10 CFR 50.55a(b)(2)(ix). The RAI also asked SNC to discuss how it is implementing a staff position that applicants for license renewal need to evaluate, on a case-by-case basis, the acceptability of inaccessible areas even though conditions in accessible areas may not indicate the presence of degradation in inaccessible areas. SNC stated that it complies with the inspection requirements of 10CFR50.55a(b)(2)(ix) with one exception. Details of this exception, which is identified as Plant Hatch's relief request MC-9, are contained in SNC's submittal to the NRC dated July 19, 2000. By letter dated October 4, 2000, the staff concluded that the proposed alternative will provide an acceptable level of quality and safety. SNC further stated that Section C.2.6.2 of the LRA identifies any applicable aging effects for steel commodities for primary containment and internal structures. Aging effects determined to require management are based on the environment present for the commodity. Each commodity was evaluated for the maximum expected conditions, such as maximum neutron exposure, elevated temperature and high humidity. SNC maintained that neutron exposure and elevated temperature do not exceed the threshold limits where degradation could occur. Other environmental conditions do not result in different aging effects for inaccessible areas than are applicable to accessible areas. Therefore, for inaccessible areas, no aging effect has been identified that is different from those resulting from the environmental conditions in the accessible areas. On the basis of the review of the above information, the staff concludes that SNC complies with the requirements for 10 CFR 50.55a(b)(2)(ix).

However, the applicant did not fully answer the second part of the question related to implementation of the staff position regarding how applicants for license renewal will evaluate the acceptability of inaccessible areas even though conditions in accessible areas may not indicate the presence of degradation in inaccessible areas. In a letter dated January 5, 2001, the staff requested the applicant to provide additional information regarding the staff position.

In its response of January 31, 2001, SNC stated that SNC’s programmatic activities related to the above item are consistent with the draft GALL. In particular, the Plant Hatch inservice inspection program included requirements of the NRC Final Rule 10 CFR 50.55a [including 10 CFR 50.55a(b)(2)(ix)] along with the ASME Section XI Subsection IWE for examination of the Class MC components. SNC further stated that at Plant Hatch, the designation “inaccessible areas” is limited to two specific areas: (a) Embedded containment shell and (b) containment basemat and buried external walls. Aging is an issue for the containment basemat and buried external walls if ground water or soil aggressive chemical limits per NUREG 1611 are exceeded.

The applicant stated that the groundwater and soil parameter at Plant Hatch are within the acceptable limits (pH>5.5, chloride<550 ppm, & sulfate<1500 ppm) specified in NUREG 1611. The soil chemistry at Plant Hatch should be essentially the same as it was before and after the plant was constructed. The soil in the vicinity of the seismic category I structures is compacted backfill with non-aggressive chemical characteristics. The soil in the remainder of the plant site area is generally undisturbed soil. Soil chemistry generally reflects the same chemical composition as the ground water and surface water to which it is exposed. The water chemistry in the Altamaha River is very nearly the same as it was when the plant was constructed. The chemistry of the soil in the vicinity of the plant buildings should also be very nearly the same as it was when the plant was constructed. Thus, SNC concluded that ground water is not aggressive, and no special aging management program is requires. However, the SMP document has been revised to include the following directive: “Additional emphasis will be placed on the importance of inspecting and documenting the condition of normally inaccessible (underground or embedded) structures, whenever the inaccessible structural components are exposed or uncovered.”

SNC also concluded that aging is not a concern for the embedded containment shell, since plant Hatch’s concrete quality in contact with the embedded containment liner meets or exceeds the requirements of ACI 318 and ACI 201.2R; the concrete is subjected to periodic inspection to assure that it is free of penetrating cracks; the moisture barrier is subject to IWE Category E-D Examination; repair or replacement is performed based on inspection results, and boric acid is not used and other chemical spills or water ponding are not common in the containment.

The staff considers the above SNC discussion fully addresses the staff position and the issue is closed.

Section A.1.9.4 of the LRA stated that loss of material, cracking, loss of pre-load, and loss of fracture toughness are the aging effects monitored by the Plant Hatch ISI Program. RAI 3.6-12 requested SNC to provide a discussion of past experience with respect to managing and monitoring these aging effects, including experience with the embedded shell and the sand pocket regions of the primary containment and the loss of pre-load for metal fasteners. SNC stated that a general discussion of operating experience related to the ISI program is provided in Section B.1.9 of the LRA. SNC further stated that visual examinations of the mastic seal between the concrete floor at elevation 114’-0” and the drywell shell inside the drywell are performed at every outage. The condition of the seal is carefully inspected to detect any cuts, tears, or observed degradation of the flexible covering over the seal. The mastic seal was replaced on Unit 1 in the fall, 1994 refueling outage. Minor, localized surface pitting was detected but was not significant. The area was cleaned and recoated prior to installation of the new seal. The mastic seal was replaced on Unit 2 in the fall, 1995 refueling outage. There has been no evidence of significant moisture intrusion between the mastic seal and drywell shell or significant deterioration of the shell on either unit. Periodic inspections of the sand cushion and associated air gap drains have confirmed that there was no moisture present or any evidence of prior leakage into the area. SNC further stated that inspections in the accessible area of the sand cushions have not shown any moisture buildup or corrosion. Visual inspections included associated bolted connections to confirm connection integrity, and no looseness of bolts or nuts has been detected that could be attributed to loss of preload.

The staff finds the response to RAI 3.6-12 adequate and acceptable. RAI 3.6-12 is closed.

Table 3.3.1-3 of the LRA does not list attachment welds to the containment shell elements as an item requiring aging management. Welds between integral attachments to the primary

containment are included within the scope of ASME Section XI, Subsection IWE. RAI 3.6-13 asked SNC to discuss how aging effects of the attachment welds will be managed. SNC indicated that attachment welds to the primary containment shell elements were considered to be a part of the component welded to the shell or the shell itself. The intended function does include pressure boundary and structural support. These intended functions are addressed in the structural steel component function column in Table 3.3.1-3 of the LRA. Therefore, welds were not singled out as a separate commodity or component and were not listed separately in Table 3.3.1-3. The applicant further indicated that the ISI program, described in Section B.1.9 of the LRA, complies with Subsection IWE of Section XI of the ASME Code and that the ISI program is the aging management program that manages aging of attachment welds to the containment pressure boundary. This is discussed in Section C.2.6.2 and Table C.2.6.2-1 of the LRA. The staff finds this response adequate and acceptable. RAI 3.6-13 is resolved.

Table 3.3.1-3 does not provide any information regarding the aging management, including surveillance requirements, for gears, latches, and linkages of personnel hatches and penetrations. RAI 3.6-15 requested SNC to identify where fretting and lockup of hinges, locks and closure mechanisms for personnel hatches is discussed in the LRA, or provide a technical justification for not considering fretting and lockup as applicable aging effects for these components. The RAI also asked SNC to provide a description of the AMP for the personnel hatches consistent with the 10 elements in the SRP-LR in sufficient detail to allow the staff to assess the adequacy of this program to manage the applicable aging effects. The applicant responded that locks and closure mechanisms are active components, and are not subject to an AMR. Therefore, fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches and penetrations are not discussed in the LRA. However, aging management for personnel airlocks, hatches, equipment hatches and penetrations are managed by the ISI program, protective coatings program, and primary leak rate testing program as discussed in LRA Sections C.2.6.2, A.1.9, A.2.3, and A.1.14. The staff position regarding fretting and lockup of hinges, locks, and closure mechanisms for personnel hatches and penetrations is that they are subject to an AMR and their aging effects should be managed by an AMP. This is Open Item 3.6.3.2-1.

Table C.1.1-1 of the LRA shows expected measured temperatures at key plant locations. With respect to the primary containment, the table does not provide maximum temperatures within key containment locations. RAI 3.6-48 asked SNC to provide maximum recorded or observed temperatures within the primary containment (both normal and abnormal temperatures) at the primary shield wall, reactor vessel supports, main steam line cubicle (or its equivalent) and the hottest regions of the SFP concrete wall locations, and as applicable, discuss the AMP for managing the aging effects of reinforced concrete components subject to a sustained high temperature environment (e.g., concrete temperature greater than 150 °F). SNC provided the requested information in response to the RAI and summarized that general elevated air temperatures near the concrete structures do not exceed 150 °F on a sustained basis, except for the sacrificial shield wall surrounding the reactor vessel. SNC also stated that local air temperatures are less than 200 °F, except for the upper elevations of the sacrificial shield wall, and the SMP will inspect the exposed and accessible concrete for loss of material, cracking and spalling. The applicant further indicated that its SMP inspection process should be able to assess the condition of the in-scope structures, and identify any ongoing degradation.

The staff noted that Tables 3.3.1-3 through 3.3.1-5 and 3.3.1-8 through 3.3.1-13 of the LRA do not list cracking of equipment support concrete pads as an applicable aging effect requiring management. Staff experience with other LRAs indicates the frequent occurrence of such cracks around anchor bolt regions. RAI 3.6-49 requested that the applicant discuss the AMP for

managing this aging effect or justify its exclusion from the tables listed above. SNC stated that equipment support foundations, pads, and anchor bolts have been subjected to an AMR. Loss of material due to corrosion of embedded steel was identified as the plausible aging effect, and cracking and spalling were identified as the aging mechanisms (see Sections C.1.4.2 and C.2.6.1 of the LRA). The SMP has been credited as the AMP, and Tables 3.3.1-3 through 3.3.1-5 and 3.3.1-8 through 3.3.1-13 list loss of material as the aging effect requiring management. SNC's responses to RAIs 3.6-48 and 3.6-49 are adequate to close the RAIs.

The applicant identified several aging management programs to manage cracking for the primary containment system components. A complete discussion on the applicable aging management programs is provided in Section 3.1 of this SER. In Table 3.3.1-3 of the LRA, the applicant included anchors and bolts, structural steel, and miscellaneous steel in non safety-related structural supports. However, it is not clear whether the scope of the primary containment system discussed in Table 3.3.1-3 of the LRA includes any spatially-related components and piping segments within the category of "Seismic II over I" (a non-seismic Category I system, structure, or component whose failure could cause loss of safety function of a seismic Category I system, structure, or component) piping. Through issuance of staff RAI 3.6-51, the applicant was requested to provide clarification. The applicant was also requested to clarify how the aging management programs for the non-safety-related piping segments and components have been addressed. Specifically, SNC was requested to state whether the same aging management programs discussed in LRA Table 3.3.1-3 also apply to those "Seismic II over I" piping components.

The applicant responded to this RAI in its letter dated October 10, 2000. The applicant stated that the pipe supports for the seismic II over I piping systems are within the scope of license renewal and they are subjected to the same AMPs as the supports for safety-related piping systems. The applicant also stated that no AMPs are applied to out-of-scope piping segments supported by seismic II over I piping supports. In a telephone conversation on October 24, 2000, the applicant further clarified that within the context of the Plant Hatch CLB, the piping systems are postulated to fall in a seismic event if not seismically supported. Thus, as required for protection of safety-related piping, some non safety-related piping is seismically supported. Those supports are within the scope of license renewal, but the applicant stated that the seismic II over I piping segments are not within the scope of license renewal. The staff finds that the programs to manage aging for the pipe supports are acceptable.

The staff does not agree with the applicant's scoping criteria for seismic II over I piping systems. The staff's position is that the seismic II over I piping segments, whose failure could prevent safety-related systems and structures from accomplishing their intended function should be within the scope of license renewal. Additional discussion of this issue is contained in Section 2.1.3.1 of this SER. This is part of Open Item 2.1.3.1-1.

A complete discussion of the applicable aging management programs may be found in Section 3.1 of this SER.

On the basis of the information discussed above, and pending resolution of Open Items 2.1.3.1-1 and 3.6.3.2-1, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the primary containment will be adequately managed by the above listed AMPs.

Reactor Building

Aging management programs cited by the applicant to manage aging effects requiring management for the reactor building are:

- protective coatings program
- structural monitoring program
- ISI program
- primary containment leak rate testing program

To manage aging effects for carbon steel anchors and bolts exposed to inside (sheltered) and outside environments; and carbon and galvanized miscellaneous steels, and structural steels made of carbon, galvanized and stainless steel, which are exposed to inside (sheltered), outside, and submerged environments, the applicant identified the protective coatings program and the structural monitoring program (SMP) as the applicable aging management programs. The protective coatings program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion. The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

To manage aging effects for panel joint seals and sealants made of elastomers (nonmetallic and inorganic), which are exposed to an inside (sheltered) or outside environment, the applicant identified the protective coatings program and the SMP as the applicable aging management programs.

To manage aging effects for concrete, masonry block, and carbon steel, which are exposed to an inside (sheltered) or outside environment, the applicant again identified the protective coatings program and the SMP as the applicable aging management programs.

The staff's detailed review of these programs may be found in Sections 3.1.9, 3.1.14, 3.1.20, and 3.1.22 of this SER.

The applicant cited the above programs to manage loss of material for the structural components exposed to the described environments. The staff has verified that the protective coatings program and SMP are included in Sections C.2.6.1 and C.2.6.3 of the LRA as applicable aging management programs. However, the staff noted a discrepancy between the information provided in Table 3.3.1-5 and Section C.2.6.7 of the LRA. Table 3.3.1-5 lists the protective coatings program and structural monitoring program as the aging management programs for panel joint seals and sealants, however, Section C.2.6.7 of the application does not list protective coatings program as the aging management program for the components. In its submittal of October 10, 2000, responding to the staff's RAI 3.6-27, the applicant stated that Table 3.3.1-5 should not have credited the protective coatings program as an aging management program for the panel joint seals and sealants. The applicant stated that the SMP manages the aging of the panel joint seals and sealants. This is acceptable to the staff.

Tables 3.3.1-3 through 3.3.1-5 and Tables 3.3.1-8 through 3.3.1-13 of the LRA do not list prestressed concrete structural components. RAI 3.6-30 asked SNC to confirm that Plant Hatch has no prestressed concrete structural elements in its structures that are subject to an AMR. Otherwise, list the prestressed concrete elements subject to an AMR and discuss applicable AMPs for managing their aging effects. SNC stated that the only prestressed elements in the

plant are precast concrete wall panels on the outside of the reactor building, turbine building, and control building. The panels on the outside of the turbine building and control building are for architectural purposes. The precast concrete wall panels around the fuel-handling area of the refueling floor of the reactor building above elevation 228 ft.-0 in. are provided to protect the refueling floor from the outside environment. The panels outside the reactor building have concrete and embedded steel, which are listed in the tables mentioned in the RAI. The SMP is the AMP applicable to the precast panels. This clarification closes RAI 3.6-30.

Primary containment leak rate testing procedures provide for the scheduled periodic testing of the primary containment pressure boundary and pressure boundary penetrations to detect degradation of the pressure boundary. Inspections are conducted in accordance with 10 CFR Part 50, Appendix J.

The ISI Program provides for visual inspections of internal and external surfaces and fasteners, thereby providing assurance that the containment shell and internal structures have not degraded due to corrosion and/or cracking. Inspections are conducted in accordance with ASME Section XI Table IWE-2500-1.

The tables in Section 3.3.1 of the LRA do not list masonry walls as structural components requiring aging management review, although Section C.1.4.2 of the LRA identifies cracking of masonry block walls as an applicable aging effect for block walls within the reactor building, control building, and main stack. RAI 3.6-47 asked SNC to discuss in detail its intent to manage the aging effects of these masonry walls and describe how the AMP for periodic inspection and surveillance of these masonry walls incorporates the insights provided in NRC IN 87-65, “Lessons Learned from Regional Inspection of Applicant Actions in Response to IE Bulletin 80-11.” SNC stated that NRC IE Bulletin 80-11 "Masonry Wall Design," indicated that, in many instances, masonry block walls had inadequate structural strength to resist pipe support, equipment, and seismic loads. This bulletin required (1) identification of masonry walls, which are in close proximity to, or have attachments from, safety-related piping or equipment, and (2) a re-evaluation of the design adequacy and construction practices. According to the IE bulletin, the masonry block wall problems resulted primarily from design and construction deficiencies, rather than from potential long-term aging degradation mechanisms. In responding to the bulletin, SNC evaluated the as-built conditions of the subject masonry block walls. Walls were prioritized by considering the relative potential for wall failure based on wall configuration loading magnitudes and span lengths. Detailed re-evaluations were performed for the worst case walls. A relatively large number of the lesser-case walls were also re-evaluated in detail to assure the structural adequacy of each, and to assure that a sufficiently large sample was selected to include all walls requiring a detailed re-evaluation. The remainder of the lesser-case walls in each priority were re-evaluated by comparison with the worst-case walls. This assured that the most critical walls were considered for prompt, detailed re-evaluation. The NRC concluded that SNC had appropriately complied with the requirements of the bulletin, and no further action was required beyond the normal inspections and evaluations committed to in response to the bulletin. NRC also revisited Plant Hatch to assure proper maintenance of the block walls per the requirements of IE Bulletin 80-11. SNC stated that masonry block wall cracks may be caused by age-related degradation mechanisms. During one walkdown, performed as part of the structural monitoring program (SMP), cracking was observed in concrete masonry block walls. The observed cracks were considered minor and insignificant by SNC, and were noted for comparison in future walkdowns.

The applicant also indicated that its SMP is intended to manage the aging effects of the block walls discussed above during the period of extended operation. Although the SNC response did

not specifically describe how the SMP incorporated the insights provided in NRC IN 87-65, the staff considers that by describing the past masonry wall walkdown experience and disposition of walkdown findings, the applicant has adequately responded to the intent of RAI 3.6-47. Thus, the staff considers the RAI resolved.

With the applicant's clarification that the SMP will be used to manage aging effects of block walls during the period of extended operation, and with the information provided by the applicant concerning its experience in using the SMP to identify age-related degradation of the block walls, the staff concludes that the SMP will be adequate to identify age-related degradation of block walls during the period of extended operation.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the reactor building will be adequately managed by the above listed AMPs.

Reactor Building Penetrations

Aging management programs determined by the applicant to manage aging effects requiring management for reactor building penetrations are:

- protective coatings program
- structural monitoring program

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The structural monitoring program provides for the visual inspection of structural components on a scheduled basis. The SMP will inspect structural components for loss of material due to general corrosion.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

A complete discussion of the applicable aging management programs may be found in Section 3.1 of this SER.

The applicant has identified the above listed programs for managing the aging of reactor building penetrations.

Tables 3.3.1-1 through 3.3.1-13 of the LRA do not list fire barrier penetration seals as components subject to an AMR. The staff views these fire barrier penetration seals as within scope and subject to an AMR. RAI 3.6-35 asked the applicant to describe how the aging effects for fire barrier penetration seals are evaluated, and to discuss the AMP used to adequately manage the effect. SNC stated that fire barrier penetration seals are addressed in LRA Table 3.2.4-18. Aging effects requiring management are listed as loss of material, change in material properties, and cracking in LRA Section C.2.3.4.1 and fire protection activities is designated as the AMP to manage these aging effects. The staff finds this response acceptable. RAI 3.6-35 is closed.

In response to RAI 3.6-45 related to the five-operating-cycle inspection period in the SMP, the applicant stated that the baseline inspection was conducted in 1998, and the next inspection is due in 2003. Thereafter the inspection period will be every five operating cycles. The SMP has criteria and guidance for adjusting the inspection interval based on the results of inspection. Considering the limited condition for operation (LCO) and surveillance requirements related to secondary containments in TS Section 3.6.4.1, the staff finds the above inspection interval criteria for reactor building penetrations acceptable and RAI 3.6-45 is closed.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups associated with the reactor building penetrations will be adequately managed by the above listed AMPs.

Turbine Building

The applicant stated that the aging management programs determined to manage aging effects requiring management for the turbine building are:

- protective coatings program
- structural monitoring program

The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material, cracking, and spalling. The SMP will also visually inspect masonry block walls for cracking.

The protective coatings program provides for periodic inspection of structural component surfaces, including fasteners and associated coatings. This program also provides for proper corrective actions to prevent or repair significant degradation of structural materials and fasteners due to corrosion.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the turbine building will be adequately managed by the above listed AMPs.

Yard Structures

The applicant stated that the aging management programs determined to manage aging effects requiring management are as follows:

- protective coatings program
- structural monitoring program

The SMP inspection process assesses the overall conditions of the listed structures, and identifies any degradation. The SMP will inspect the concrete commodities for loss of material.

The protective coatings program provides for the prevention and mitigation of corrosion of embedded steel at the surface of the concrete.

The staff's detailed review of these programs may be found in Sections 3.1.20 and 3.1.22 of this SER.

On the basis of the information discussed above, the staff concludes that the applicant has demonstrated that the aging effects for the commodity groups for the yard structures will be adequately managed by the above listed AMPs.

3.6.4 Conclusion

The staff has reviewed the information in Section 2.4, "Structures Screening Results"; Section 3.3.1, "Civil Structural Components"; A.1, "Existing Programs and Activities"; A.2, "Enhanced Programs and Activities"; A.3, "New Programs and Activities"; B.1, "Existing Programs and Activities"; B.2, "Enhanced Programs and Activities"; B.3, "New Programs and Activities"; and C.2.6, "Aging Management Review for Civil Discipline Commodities" of the LRA. On the basis of this review, pending satisfactory resolution of Open Items 2.1.3.1-1, 3.6.3.1-1, and 3.6.3.2-1, the staff concludes that the applicant has adequately identified the aging effects associated with structures and structural components and has demonstrated that the aging effects associated with the structures and structural components will be adequately managed so that there is reasonable assurance that these structures and structural components will perform their intended functions in accordance with the CLB during the period of extended operation.

3.7 Electrical and Instrumentation and Controls

The applicant described its AMR for electrical components at Plant Hatch in Section C.2.5, "Aging Management Reviews For Electrical Discipline Commodities" of the LRA. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging on the electrical components will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.7.1 Summary of Technical Information in the Application

Section C.1.3 of the LRA identified the applicable aging effects for electrical components. The process to determine aging effects applicable to electrical components began with an understanding of the aging effects identified in the industry literature. The components that require aging management were determined by examining the component materials, service environments, and operating stresses for each component type. In addition to the industry literature review, plant-specific operating experience was reviewed to provide reasonable assurance that all aging effects were identified for the AMR.

External environments are defined in Sections 3.1.2.8, "Inside;" 3.1.2.9, "Outside;" and 3.1.2.10, "Buried or Embedded" of the LRA. "Inside" external environments are defined as environments where equipment is sheltered from the weather. "Outside" external environments are defined as environments found outside a structure where equipment would not be sheltered from the weather. "Buried or embedded" external environments are defined as environments beneath the surface of the ground (in some cases with controlled backfill) or embedded in structural concrete. Structures and components which perform their functions in external environments are, in general, discussed in Sections 3.2, 3.3, 3.4, 3.5, 3.6, and 3.7 of the LRA, and are evaluated in Sections 3.6 and 3.7 of this SER, unless otherwise noted.

3.7.1.1 Effects of Aging

Electrical cables, connectors, splices, terminal blocks, Nelson frames, and phase bussing are the electrical component types that are subject to an AMR. Based on available industry literature, the following aging effects have been identified for these electrical components requiring aging management:

- loss of material
- cracking/embrittlement
- loss of conductivity
- change in insulation resistance
- change in material properties

Depending upon the environmental conditions that are present, the above aging effects can be expected to occur due to the following aging mechanisms:

- thermal degradation of organic materials

    - loss of material
    - cracking/embrittlement
    - change in material properties
    - change in insulation resistance

- thermoxidative degradation

    - loss of material
    - cracking/embrittlement
    - change in material properties
    - change in insulation resistance

- radiolysis of organic materials

    - cracking/embrittlement
    - change in insulation resistance
    - change in material properties

- water treeing

    - change in insulation resistance

The aging effects associated with nonmetallic materials used in electrical components at Plant Hatch were assessed by evaluating the environmental conditions associated with high temperature, radiation, and moisture. High temperature can result in thermal degradation and thermoxidative degradation of electrical components. A radiation environment can result in radiolysis of organic materials. Water penetration into electrical cable insulation can result in reduced dielectric strength due to increased conductivity of the insulation caused by increased ion mobility and concentration.

3.7.1.2 Aging Management Programs

On the basis of the review of industry literature and plant-specific operating experience, the applicant maintains that, with the exception of the 4-kV power and transformer feeder cables and insulated cables, connectors, splices, and terminal blocks, the aging effects identified above for Nelson frames and phase bussing do not require an aging management program.

3.7.2 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Sections 3.4, A.1.16, C.1.3, and C.2.5 of the LRA regarding the applicant's demonstration that aging effects will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation for the electrical components. After completing the initial review, the staff issued requests for additional information on July 14 and July 28, 2000. The responses were received on October 10, 2000 and January 31, 2001.

3.7.2.1 Effects of Aging

As discussed in Section 3.7.1.1 of this SER, the applicant identified potential aging effects for license renewal by reviewing available industry literature and plant-specific operating experience. These effects include loss of material, cracking/embrittlement, change in material properties, and change in insulation resistance. The staff evaluated the applicant's identification of these potential aging effects for the phase bussing, Nelson frames, cables, splices, connectors, and terminal blocks.

3.7.2.1.1 Aging Effects on Phase Bussing Caused by High Temperature and Radiation

The materials associated with the phase bussing include various polymers, galvanized and stainless steel, and tinned and bare copper. Phase bussing is subjected to an internal environment due to "self heating," and an external environment of "inside" (excluding containment). Inside environments are defined in Section 3.1.2.8 of the LRA as environments where equipment is sheltered from the weather. The phase bussing inside environment is associated with the electrical bus between the 4160/600 volt station auxiliary transformer CD and 600v buses C and D.

A review of operating experience based on the condition reporting database identified that approximately 122 deficiencies had been written on the power transformer system associated with phase bussing. The applicant screened these deficiencies to determine which ones might be potentially age-related. No age-related failures of the in-scope phase bussing components were found.

The materials of construction for the portion of phase bussing that is in scope were evaluated for 60-year temperatures and radiation doses based on industry material databases. The 60-year temperatures and allowable doses were greater than the expected temperatures and radiation doses in all cases. Therefore, no aging effects associated with temperature and radiation require aging management for in-scope electrical phase bussing.

The staff agrees with the applicant's assessment and conclusion that, on the basis of the review of industry information, plant-specific operating experience, and evaluation of the materials of construction for 60-year expected temperatures and radiation doses, no aging effects that would lead to a loss of intended function are applicable for phase bussing, and no AMP is necessary.

3.7.2.1.2 Aging Effects on Nelson Frames

The materials associated with Nelson frames consist of various polymers and galvanized and painted steel. Nelson frames are located in the walls and floors of the reactor building with an external environment of “inside” (excluding containment). Nelson frames are located in the wall between the reactor building and turbine building, in the wall between the reactor building and the control building, and between floors of the reactor building. Reactor building electrical penetrations allow cables to penetrate the secondary containment boundary and maintain secondary containment leakage rates within design limits.

A review of the condition reporting database did not identify any deficiencies of the reactor building penetration system, which contains the Nelson frames. The materials of construction for the Nelson frames were evaluated for 60-year temperatures and radiation doses based on industry material databases. The 60-year temperatures and allowable doses were greater than the expected temperatures and radiation doses in all cases. Therefore, no aging effects associated with temperature and radiation require aging management for Nelson frames.

The staff agrees with the applicant’s assessment and conclusion that, on the basis of the review of industry information, plant-specific operating experience, and evaluation of the materials of construction based on 60-year expected temperatures and radiation doses, no aging effects that would lead to a loss of intended function are applicable for Nelson frames, and no AMP is necessary.

3.7.2.1.3 Aging Effects on Cables, Connectors, Splices, and Terminal Blocks

The aging effects discussed in this subsection are associated with cables, connectors, splices, and terminal blocks that are not managed by the applicant’s environmental qualification program. The applicant’s aging management of environmentally qualified cables, connectors, splices, and terminal blocks is considered a TLAA and is discussed in Section 4.4 of the LRA. The staff’s evaluation of this section can be found in Section 4.4 of this SER.

The materials associated with cables, connectors, splices, and terminal blocks consist of various polymers, tinned and bare copper, and galvanized and stainless steel. Insulated electrical cable at Plant Hatch is located in an external environment of “inside” and “outside.” Some cables could be exposed to submergence. Electrical splices, connectors, and terminal blocks are located in an external environment of “inside” and “outside,” and are installed throughout the plant, in the drywell, and in outdoor pits.

The effects of moisture on medium-voltage cables can result in water trees when the insulating materials are exposed to long-term, continuous-voltage stress and moisture, eventually resulting in breakdown of the dielectric and failure. The growth and propagation of water trees are somewhat unpredictable, and few occurrences have been discovered for cables operated below 15 kV. Water treeing has been documented for medium-voltage electrical cables with cross-linked-polyethylene (XLPE) or high-molecular-weight polyethylene (HMWPE) insulation. Recently, medium-voltage cables with ethylene propylene rubber insulation have failed after being exposed to long-term, continuous-voltage stress and significant moisture. Plant Hatch wetted cables activities provide for mitigating activities as well as condition monitoring activities for 4-kV power cables and transformer feeder cables that are within the scope of license renewal. Wetted cables activities are discussed in Section B.1.16 of the LRA. The staff’s review of wetted cables activities can be found in Section 3.1.16 of this SER.

Radiation-induced degradation in cable jacket and insulation materials produces changes in organic material properties, including reduced elongation, and changes in tensile strength. Visual indications of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. For cables, connectors, splices, and terminal blocks, the applicant has provided an "Insulated Cables and Connections Aging Management Program," by letter dated January 31, 2001.

Thermal-induced degradation in cable jacket and insulation materials can result in reduced elongation and changes in tensile strength. Visible indications of thermal aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. The Arrhenius methodology was used by the applicant for temperatures corresponding to a 60-year service life for cables, connectors, splices, and terminal blocks. These temperatures were compared to the maximum bounding temperatures of the various plant areas. For cables, connectors, splices, and terminal blocks, the applicant has provided an "Insulated Cables and Connections Aging Management Program," by letter dated January 31, 2001.

The staff agrees with the applicant's assessment regarding the wetted cables activities for moisture for the 4-kV power cables and transformer feeder cables and with the applicant's assessment associated with temperature and radiation for cables, connectors, splices, and terminal blocks.

3.7.2.2 Aging Management Programs

3.7.2.2.1 Aging Management Program for Wetted Cables

The wetted cables activities at Plant Hatch provide for mitigating activities as well as condition monitoring activities. Plant Hatch wetted cables activities include monitoring for and removing water, along with testing to detect changes in insulation resistance. Several 4-kV power cables and transformer feeder cables within the scope of license renewal are routed through the underground duct bank system consisting of outdoor pull boxes containing underground conduits routed between in-scope buildings. Change in insulation resistance is the aging effect that is mitigated and monitored by the wetted cables activities.

The water level is measured, recorded, and the pull boxes drained where these in-scope 4-kV power and transformer cables are routed. Megger and polarization index testing are periodically performed. When new terminations are made, the cables are hipot tested to provide additional assurance that the cable insulation integrity is sound. In addition, the pull boxes are drained quarterly and testing is performed on in-scope 4-kV motor windings and the associated feeder cables during regular motor and pump maintenance tasks.

The wetted cables activities meet the intent of IEEE 43-1974, "Recommended Practice for Testing Insulation Resistance of Rotating Machinery"; and IEEE 95-1977," Recommended Practice for Insulation Testing of Large AC Rotating Machinery with High Direct Voltage." Pull boxes found to contain water are drained to 1 inch of water or less. Cables and loads must successfully pass megger and polarization index testing. Corrective actions are taken if testing results are unacceptable. Plant specific operating experience did not identify any in-scope age-related cable failures due to moisture intrusion.

The staff finds that the Plant Hatch wetted cables activities manage the effects of cable aging due to moisture intrusion so that the intended functions will be maintained consistent with the CLB for the period of extended operation (see Section 3.1.16 of this SER).

3.7.2.2.2 Aging Management Program for Cable, Connectors, Splices, and Terminal Blocks

Sections 3.4, C.1.3, and C.2.5 of the LRA conclude that no aging effects associated with high temperature and radiation require aging management for cables, connectors, splices, and terminal blocks. On July 14, 2000, the staff issued RAI 2.5 requesting that the applicant provide a description of the following:

- an aging management program for accessible and inaccessible electrical cables and connections that may be exposed to an adverse localized environment caused by heat or radiation

- an aging management program for accessible and inaccessible electrical cables used in instrumentation circuits that are sensitive to a reduction in conductor insulation resistance exposed to an adverse localized environment caused by heat or radiation

By letter dated October 10, 2000, the applicant acknowledged that industry information exists regarding the effects of temperature and radiation on electrical cables and connections, including the information on cable aging in the staff's Generic Aging Lessons Learned (GALL) Report. By letter dated January 31, 2001, the applicant provided a description of an "Insulated Cables and Connections Aging Management Program." The insulated cables and connections AMP is a condition monitoring program designed to confirm that age-related degradation is not inhibiting component function of insulated cables and connections within the scope of license renewal during the period of extended operation. The staff evaluation of this AMP is found in Section 3.1.30 of this SER.

The staff finds that the Plant Hatch insulated cables and connections AMP manages the effects of aging due to radiation and temperature so that the intended functions will be maintained consistent with the CLB for the period of extended operation.

3.7.3 Conclusion

The staff has reviewed the information in Section 3.4, A.1.16, C.1.3, and C.2.5 of the LRA as well as the additional information provided by the applicant in RAI response dated October 10, 2000, and by letter dated January 31, 2001. On the basis of this review, the staff concludes that the applicant has adequately identified the aging affects associated with electrical components, and has demonstrated that the aging effects associated with electrical systems and components at Plant Hatch will be adequately managed so that there is reasonable assurance that these systems and components will perform their intended functions in accordance with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

4.1.1 Introduction

The applicant described its identification of time-limited aging analyses (TLAA) in Section 4.1.1, "Identification and Evaluation of Time-Limited Aging Analyses," of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has identified the TLAAs as required by 10 CFR 54.21(c).

4.1.2 Summary of Technical Information in the Application

The applicant evaluated calculations for Plant Hatch against the six criteria specified in 10 CFR 54.3 to identify the TLAAs. The applicant identified the following TLAAs:

- Piping stress analyses that consider thermal fatigue cycles defined by the life of the plant.
- Fatigue/stress analyses for the torus structure and nozzle connections.
- Piping wall thickness calculations that develop acceptable as-measured criteria for pipe walls based upon an anticipated corrosion rate that, in turn, is based upon the life of the plant.
- Calculation of the corrosion allowance assumed for the reactor vessel.
- Environmental equipment qualification calculations that qualify electrical components for 40 years.
- A containment penetration structural analysis that assumes a number of pressurization cycles over the 40-year life of the plant.
- Calculation of the reference temperature for nil-ductility for critical core region vessel materials accounting for radiation embrittlement (as required by 10 CFR Part 50, Appendix G).
- Calculation of the end-of-life equivalent Charpy Upper-Shelf Energy margin (as required by 10 CFR Part 50, Appendix G) due to the extended operating term.
- Analyses performed to demonstrate the acceptability of a technical alternative to the Code requirement for inspection of reactor pressure vessel circumferential welds.
- Change in the anticipated operating cycles of the main steam isolation valves (MSIVs) from the number of cycles assumed for 40 years in the Plant Hatch FSAR.

Pursuant to 10 CFR 50.21(c)(2), the applicant stated that no exemptions granted under 10 CFR 50.12 that were based on a TLAA were identified. The applicant did identify that a technical alternative (as defined in 10 CFR 50.55a(a)(3)(i)) to requirements to inspect circumferential welds on the reactor pressure vessel had been approved. This TLAA is discussed in Section 4.6 of this SER.

4.1.3 Staff Evaluation

As indicated by the applicant, TLAAs are defined in 10 CFR 54.3 as analyses that meet the following six criteria:

- involve systems, structures, and components within the scope of license renewal, as delineated in Section 54.4(a)
- consider the effects of aging
- involve time-limited assumptions defined by the current operating term, for example, 40 years
- were determined to be relevant by the applicant in making a safety determination
- involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in Section 54.4(b)
- are contained or incorporated by reference in the CLB

Table 4.1.1-1 of the LRA did not identify flaw growth analysis as a TLAA. Flaws in Class 1 components that exceed the size of allowable flaws defined in IWB-3500 of the ASME Code need not be repaired if they are analytically evaluated to the criteria in IWB-3600 of the ASME Code. The analytic evaluation requires the applicant to project the amount of flaw growth due to fatigue and stress corrosion cracking mechanisms, or both, where applicable, during a specified evaluation period. In RAI 4.1-1 the staff asked the applicant to identify all Class 1 components that have flaws exceeding the allowable flaw limits defined in IWB-3500 and that have been analytically evaluated to IWB-3600 of the ASME Code and to provide the results of the analyses that indicate whether the flaws will satisfy the criteria in IWB-3600 for the period of extended operation. In response, the applicant stated that the review of flaw growth analyses for Plant Hatch did not identify any that meet the definition of a TLAA per the criteria of 10 CFR 54.3. The applicant further indicated that most flaw evaluations were performed for a 40-month period and no flaw evaluations were performed for a 40-year period. The staff agrees that evaluations based on 40-month time periods do not constitute TLAAs per the definition in 10 CFR 54.3.

Table 4.1.1-1 of the LRA identifies piping stress analyses that consider thermal fatigue cycles as a TLAA. The table does not identify the fatigue analyses of other reactor coolant pressure boundary components or the reactor vessel internals as TLAAs. Section 4.2 of the LRA does address the reactor pressure vessel. In RAI 4.1-2 the staff asked the applicant to identify other components of the reactor coolant pressure boundary that have fatigue analyses. The staff also asked the applicant to describe the TLAAs performed to address fatigue for the reactor coolant pressure boundary components, except for the reactor vessel, that were not included in Table 4.1.1-1, and to describe the TLAA performed for the reactor vessel internals. The applicant was also asked to indicate how these TLAAs meet the requirements of 10 CFR 54.21(c). In response, the applicant stated that the criteria of BWRVIP-74 was used to determine which fatigue analyses were significant enough to be a TLAA. As indicated in the RAI, the applicant discussed the fatigue analysis of the reactor vessel internals in the FSAR. The staff requests that the applicant explain how the fatigue analysis of the vessel internals was found to be acceptable for the 60-year period. The staff also requests that the applicant identify any other

components of the reactor coolant pressure boundary that had fatigue analyses and explain how these analyses were found acceptable for the 60-year period. This is part of Open Item 4.1.3-1.

Section 4.2.2 of the LRA contains a discussion of the Plant Hatch licensing basis pipe break criteria. Part of the Plant Hatch pipe break criteria involves postulation of pipe breaks at locations where the calculated fatigue usage exceeds a specified value. Although the applicant identified the fatigue cumulative usage factor (CUF) calculation as a TLAA, the applicant concluded that the pipe break criteria was only a screening criteria and not a TLAA (the specific design criterion pertaining to the fatigue evaluation of RCS components involves calculating a quantity called the cumulative usage factor. 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). The usage factor calculation used to identify postulated pipe break locations meets the definition of a TLAA as specified in 10 CFR 54.3. In RAI 4.2-1 the staff asked the applicant to provide a description of a TLAA for the pipe break criteria at Plant Hatch and to describe how the TLAA meets the requirements of 10 CFR 54.21(c). In response, the applicant stated that it views the pipe break criteria to be a selection criteria that establishes a bounding set of locations for line break consideration. Although the staff agrees with the applicant's statement, the staff still considers pipe break postulations a TLAA because the fatigue calculation is a TLAA. Additionally, the NRC previously identified high-energy line break postulation based on fatigue cumulative usage factor as a TLAA in accordance with 10 CFR 54.3 (60 FR 22480, May 8, 1995). Therefore, the staff requests that the applicant include pipe break postulations based on fatigue usage factor as a TLAA. This is part of Open Item 4.1.3-1.

4.1.4 Conclusions

The staff has reviewed the information in Section 4.1.1, "Identification and Evaluation of Time-Limited Aging Analyses," of the LRA. On the basis of the review, and pending satisfactory resolution of Open Item 4.1.3-1, the staff concludes that the applicant has adequately identified the TLAAs as required by 10 CFR 54.21(c) and that no 10 CFR 50.12 exemptions have been granted on the basis of a TLAA, as defined in 10 CFR 54.3.

4.2 Pipe Stress

4.2.1 Introduction

The applicant described its evaluation of pipe stress time-limited aging analyses (TLAA) in Section 4.2, "Pipe Stress Time-Limited Aging Analyses" of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has adequately evaluated the TLAA as required by 10 CFR 54.21(c).

A metal component subjected to cyclic loads may fail at a load magnitude less than its ultimate load capacity due to metal fatigue, initiating and propagating 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. Fatigue was a design consideration for piping and components and, consequently, fatigue is part of the current licensing basis (CLB) for Plant Hatch. The applicant identified fatigue as TLAAs for piping stress analyses that consider thermal cycles defined by the life of the plant and fatigue/stress analyses for the torus structure and nozzle connections. The staff reviewed Section 4.2 of the LRA, which discusses thermal fatigue of piping and fatigue of the torus structure.

4.2.2 Summary of Technical Information in the Application

The applicant discusses the design criteria for thermal fatigue in Section 4.2.1 of the LRA. Class 1 piping was explicitly evaluated for thermal transients specified in the FSAR. As indicated in Table 4.2.2-1 of the LRA, the Class 1 (RCS) piping at Unit 1 was designed to the United States of America Standard (USAS) B31.7 Class 1 criteria and Unit 2 was designed to ASME Code Section III Subsection NB criteria. The criteria of both codes require that the calculated fatigue cumulative usage factor (CUF) resulting from the thermal transients not exceed the specified code limit of 1.0. As indicated in Table 4.2.3-1 of the LRA, Non-Class 1 piping was designed to either USAS B31.1, USAS B31.7 Class 2 and 3, or ASME Subsection NC and ND criteria. The criteria of these codes specify a stress reduction factor to be applied to the allowable thermal bending stress range if the number of cycles exceeds 7,000.

The applicant discusses the evaluation of Class 1 components in Section 4.2.2 of the LRA. The applicant indicated that Class 1 fatigue TLAAs would be addressed by an aging management program. The aging management program is described in Section A.1.12 of the LRA. The aging management program monitors the CUF of specific bounding locations at Plant Hatch. These locations include four components of the Reactor Pressure Vessel (RPV); closure studs, the shell, the recirculation inlet nozzles, and the feedwater nozzles. In addition, the following Class 1 piping locations are monitored:

- Unit 1 RPV equalizer piping;
- Unit 1 core spray piping (for replaced piping outside of the RPV);
- Unit 1 standby liquid control piping;
- Unit 1 feedwater, high pressure coolant injection (HPCI), reactor core isolation cooling (RCIC), reactor water cleanup (RWCU) system piping;
- Unit 1 main steam piping (loop B);
- Unit 2 main steam piping (loop D);
- Unit 2 residual heat removal (RHR) suction piping;
- Unit 2 feedwater piping; and
- Unit 2 steam condensate drainage piping.

The applicant monitors these locations using its Component Cyclic or Transient Limit Program (CCTLP) which is discussed in Section A.1.12 of the LRA. The staff evaluation of this program in contained in Section 3.1.12 of this SER.

The applicant also discusses the design criteria used for the postulation of pipe break and Generic Safety Issue (GSI)-190, “Fatigue Evaluation of Metal Components for 60-year Plant Life.” The applicant states that the pipe break criteria are not a TLAA. The applicant relies on generic industry studies to address the environmental fatigue concerns identified in GSI-190.

The applicant discusses the evaluation of Non-Class 1 piping in Section 4.2.3 of the LRA. For Non-Class 1 piping, a stress reduction factor would have been applied if the number of

equivalent full-temperature cycles exceeded 7,000. The applicant indicated that based on a review of the FSAR, operations manual, and operating history, the estimated number of full-temperature cycles that the Non-Class 1 piping would experience for 60 years is substantially less than the number assumed in the analyses.

The applicant discusses the evaluation of the torus structure in Section 4.2.4 of the LRA. The applicant indicated that several calculations related to the torus structure constituted fatigue TLAAs. The applicant indicated that a new analysis of the torus was performed to address fatigue for the period of extended operation.

4.2.3 Staff Evaluation

Components of the RCS were designed to codes that contained explicit criteria for the fatigue analysis. Consequently, the applicant identified fatigue analyses of some RCS components as TLAAs. In Section 4.1 of this SER, the staff questioned whether the applicant has identified all the TLAAs. The staff reviewed the applicant’s evaluation of the identified RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The applicant monitors limiting locations in the RPV and RCS piping for fatigue usage through the use of its CCTLP. The applicant indicated that actual operating history was used to project a 60-year CUF for each unit (the specific design criterion pertaining to the fatigue evaluation of RCS components involves calculating a quantity called the cumulative usage factor. 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). The applicant further indicated that all monitored locations are projected to have a CUF less than 1.0 after 60 years of operation. Even though the applicant projects that the CUF of the limiting locations will not exceed 1.0 during the period of extended operation, the applicant relies on the CCTLP to monitor the CUF and manage fatigue in accordance with the provisions of 10 CFR 54.21(c)(1)(iii). The staff evaluation of the CCTLP is contained in Section 3.1.12 of this SER.

The applicant's CCTLP tracks transients and cycles of RCS components that have explicit design basis transient cycles to ensure that these components stay within their design basis. Generic Safety Issue (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 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, "Completion of the Fatigue Action Plan."

The staff assessment for GSI-166 provides a basis for the current 40-year plant design life. However, the staff assessment took credit for the conservatism in the CLB 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 CCTLP tracks fatigue cycles of RCS components and compares the cycles to those used in the CLB evaluation. 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. The recommendation was 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 period of extended operation.

By letter dated February 9, 1998, the Electric Power Research Institute (EPRI) submitted two EPRI technical reports dealing with the fatigue issue. EPRI Reports TR-107515, "Evaluation of Thermal Fatigue Effects on Systems Requiring Aging Management Review for License Renewal for the Calvert Cliffs Nuclear Power Plant," and TR-105759, "An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations" were 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 reports. The staff technical concerns were transmitted to the Nuclear Energy Institute (NEI) by letter dated November 2, 1998. NEI responded to the staff concerns in a letter dated April 8, 1999. The staff submitted its assessment of the response in an August 6, 1999, letter to NEI. As indicated in the staff letter, the NEI response did not resolve all staff technical concerns regarding the EPRI reports.

The applicant indicates that EPRI license renewal fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects for Plant Hatch. As discussed above, the staff does not agree with the contention that the EPRI fatigue studies have demonstrated that sufficient conservatism exists in the design transient definitions to compensate for potential reactor water environmental effects.   Although the August 6, 1999, letter identified staff concerns regarding the EPRI procedure and its application to PWRs, the technical concerns regarding the application of the Argonne National Laboratory (ANL) statistical correlations and strain threshold values are also relevant to BWRs. In addition to the concerns referenced above, the staff has additional concerns regarding the applicability of the EPRI BWR studies to Plant Hatch. EPRI Report TR-107943, “Environmental Fatigue Evaluations of Representative BWR Components,” addressed a BWR-6 plant and EPRI Report TR-110356, “Evaluation of Environmental Thermal Fatigue Effects on Selected Components in a Boiling Water Reactor Plant,” used plant transient data from a newer vintage BWR-4 plant. In RAI 4.2-2, the staff requested that the applicant provide additional information regarding the use of the EPRI license renewal fatigue studies to resolve the environmental fatigue issue at Plant Hatch.

In response to the RAI, the applicant discussed its assessment of the impact the environmental correction factors for carbon and low-alloy steels contained in NUREG/CR-6583, “Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,” and those for austenitic stainless steels contained in NUREG/CR-5704, “Effects of LWR Coolant Environments on Fatigue Design of Austenitic Stainless Steels” on the results of the EPRI studies. As a result of its assessment, the applicant concluded that the correlations have been adequately accounted for via the conservatism of the design basis transients.

The applicant indicated that EPRI Report TR-110356 contained studies that are directly applicable to Plant Hatch because the study involved a BWR-4 that is identical to the Plant Hatch design. The only components evaluated in TR-110356 are the feedwater nozzle and the control rod drive penetration locations. However, the applicant indicated that both Plant Hatch units employ hydrogen water chemistry, whereas the plant in the EPRI study did not consider hydrogen water chemistry. Hydrogen water chemistry affects the level of dissolved oxygen in

the primary system. Dissolved oxygen is an important factor in the environmental fatigue effects. The applicant stated that this issue was adequately addressed by its evaluation of the feedwater nozzle contained in EPRI Report TR-105759. It is not clear to the staff how the issue of hydrogen water chemistry was addressed in EPRI Report TR-105759. The applicant's response has not resolved the staff concerns regarding the environmental fatigue issue at Plant Hatch.

The staff requested that the applicant provide an assessment of the six locations identified in NUREG/CR-6260, "Application of NUREG/CR-5999, 'Interim Fatigue Curves to Selected Nuclear Power Plant Components'," March 1995, for an older vintage BWR (BWR-4) considering the applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704 reports for Plant Hatch Units 1 and 2. The applicant indicated that these locations are monitored by the CCTLP and that the environmental factors have been adequately accounted for by the conservatism in the design basis transient definitions. On the basis of the discussion above, the staff does not agree with the applicant that environmental fatigue concerns regarding the six locations identified in NUREG/CR-6260 have been adequately addressed at Plant Hatch. The applicant is therefore requested to assess these six locations, considering applicable environmental fatigue correlations provided in NUREG/CR-6583 and NUREG/CR-5704, as applicable. This is Open Item 4.2.3-1.

The applicant discusses the TLAA for non-Class 1 piping in Section 4.2.3 of the LRA. The design code for non-Class 1 piping and tubing controls fatigue by limiting the allowable range of bending stresses resulting from the restraint of free-end expansion. The code provides for a reduction of the allowable stress range if the number of cycles exceeds 7000 full-range stress cycles. The applicant indicated that it estimated that the number of thermal cycles that non-Class 1 piping and tubing would encounter in 60 years of operation is substantially less than the number assumed in the original design. The applicant indicates that the current design basis for some piping and tubing is 14,000 cycles. In RAI 4.2-3 the staff requested that the applicant identify the piping and tubing that were designed for 14,000 cycles and provide the basis for this specified number of cycles. In response, the applicant indicated that 14,000 cycles was assumed in design guides for instrumentation tubing and supports based on a designer's rule-of-thumb approach. The applicant further indicated that the assumption is very conservative in that it implies a thermal cycle every 1.5 days over a 60-year operational life. The staff agrees with the applicant's assessment that the number of assumed cycles is conservative. The staff finds that the applicant's assessment satisfies the provisions of 10 CFR 54.21(c)(1)(i) by demonstrating that the analysis remains valid for the period of extended operation.

The applicant discusses its evaluation of the torus structure in Section 4.2.4 of the LRA. According to the applicant, several calculations that addressed fatigue of the torus structure met the criteria for a TLAA. The applicant indicated that a new analysis was necessary to address fatigue in the torus for the period of extended operation. The applicant indicated that the critical event leading to fatigue damage of the torus is the lifting of one or more main steam system safety relief valves (SRVs). The applicant proposes to manage fatigue of the torus by monitoring the number of SRV lifts in its CCTLP. The staff evaluation of the CCTLP is contained in Section 3.1.12 of the safety evaluation.

4.2.4 Conclusion

The staff has reviewed the information in Section 4.2, “Pipe Stress Time-Limited Aging Analyses” of the LRA. On the basis of the review, and pending satisfactory resolution of Open Item 4.2.3-1, the staff concludes that the applicant has adequately evaluated the pipe stress TLAA, as required by 10 CFR 54.21(c)(1).

4.3 Corrosion Allowance

4.3.1 Introduction

The applicant described its evaluation of the corrosion allowance TLAA in Section 4.3, “Corrosion Allowance,” of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has adequately evaluated the TLAA as required by 10 CFR 54.21(c).

An allowance for corrosion was made in determining the appropriate thickness for pressure retaining components in the design of Plant Hatch. Only those analyses containing an assumption of a corrosion allowance that also tied the allowance to a 40-year operating life meet 10 CFR 54.3 Criterion 3. In the review of the Plant Hatch analyses, two scopes of supply are important; the equipment designed and supplied by Bechtel and the equipment designed and supplied by General Electric (GE).

4.3.2 Summary of the Technical Information in the Application

Bechtel Power Corporation Scope of Supply

The assumption of a corrosion allowance appears in calculations that confirm the pressure rating of piping and components. The piping specifications for both units of Plant Hatch specify corrosion allowances for types of piping based upon material and environment. In most of the calculations reviewed, the corrosion allowance assumed was not tied to a 40-year life of the component. Additionally, corrosion rates were not identified (with specific exceptions discussed below). Many of the calculations used standard values from Table A104.2 of ASME B31.1. Once a required minimum wall thickness was calculated, the design often chose the next thicker component size (e.g., the next higher pipe schedule). For these reasons, calculations covering components in the Bechtel scope of supply generally do not meet the definition of a TLAA.

There is a subset of analyses that are the exception to the above paragraph. In the course of evaluating the residual heat removal service water system piping and the plant service water system piping in accordance with Nuclear Regulatory Commission (NRC) Generic Letters 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” and 90-05, “Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping,” Bechtel performed calculations to develop evaluation levels for measurements on the piping. These levels were in part based upon the expected thickness of a pipe and upon the predicted wear of that pipe for the remaining service life. In these analyses, the corrosion allowance from the pipe specification was assumed to be the maximum allowed for the 40-year service life of the piping. The corrosion rate thus defined is used in the calculations to predict the expected pipe thickness and to develop the minimum acceptable as-found thickness of the pipe.

These calculations were instrumental in developing the inspection program for the residual heat removal and primary service water piping, much of which is in-scope for license renewal. The formulae used in the calculations have been retained in the inspection program procedure used at Plant Hatch.

The plant service water and RHR service water piping inspection program establishes screening levels for the piping. Therefore, the calculations are conservative for the extended term and do not require revision. The plant service water and RHR service water inspection program will continue to manage the effects of aging (corrosion) for the extended license term, as required by 10 CFR 54.21(c)(1)(i) and (iii).

General Electric Scope of Supply

In reviewing the documents within the design records database, SNC found no GE calculation or analysis that explicitly defined the corrosion allowance as a function of 40 years. Therefore, the plant service water and RHR service water inspection program uses one of two corrosion rates to predict the minimum acceptable measured pipe wall thickness. The first rate is defined by dividing the specified corrosion allowance by 40 years. The second rate is an observed corrosion rate based upon several measurements of the pipe wall. The greater of the two corrosion rates is used to predict the acceptable minimum wall thickness. The action levels of the procedure are also based, in part, on the corrosion rate determined by the corrosion allowance.

The impact of an extended operating period on the inspection program is minimal. A change to the specification-based corrosion rate would not be conservative and is not necessary. Decreasing the corrosion rate (by dividing the current allowance by 60 rather than 40 years) is not appropriate, because a rate thus calculated would not be conservative. Therefore, SNC contracted GE to make a further determination within their scope of supply. The GE review developed the following conclusions about the stainless steel components, general piping, and reactor vessel. For austenitic stainless steel components in the Plant Hatch reactor system, the corrosion allowance was not explicitly calculated using a 40-year assumption. The corrosion rate for stainless steel under BWR conditions is very low, and the corrosion allowance will be adequate through the end of the renewal term. With respect to the reactor vessel, GE reviewed its internal communications, reports, and open literature to determine the method for calculating the Plant Hatch Units 1 and 2 corrosion allowance. The GE review determined that a time-dependent corrosion rate was used and that the corrosion allowance was based upon a 40-year assumption for the service life of the vessel. Since this corrosion allowance was determined to meet all six criteria, the corrosion allowance is a TLAA. GE has evaluated the corrosion allowance for the vessel and has determined that the allowance is adequate for operation through the end of the renewed license term, as required by 10 CFR 54.21(c)(1)(ii).

4.3.3 Staff Evaluation

Bechtel Power Corporation Scope of Supply

The staff has reviewed the discussion of the Bechtel Power Corporation scope of supply. Bechtel based the corrosion allowances on the type of piping and the environment, which the staff agrees is appropriate. The applicant reviewed the calculations and generally found that standard values from Table A104.2 of ASME B31.1 were used. After calculating a minimum wall

thickness, the next higher pipe schedule was selected. The staff agrees that this is standard practice. The applicant determined that the calculations in the Bechtel scope of supply generally do not meet the definition of a TLAA and the staff agrees.

For the plant service water piping and residual heat removal service water piping, the applicant conducted TLAAs on this piping based on a 40-year lifetime. The applicant divided the corrosion allowance by 40 years to develop a corrosion rate. This corrosion rate is used to determine the minimum pipe wall thickness at any time from the present to the end-of-life. Based on this calculation, the applicant developed an inspection plan for the residual heat removal and plant service water piping. Actual pipe wall thickness is measured and compared to the calculated wall thickness. The actual corrosion rate is calculated from the measured wall thickness and the time of service. The higher corrosion rate of the calculated value and the measured rate is used to predict the wall thickness at end-of-life. Since the corrosion allowance is somewhat arbitrary, the calculated corrosion rate is also arbitrary and is not a particularly accurate predictor of future wall thickness. However, supplementing the calculated rate with measured rates gives credibility to the program. Therefore, the staff finds that this program is acceptable.

General Electric Scope of Supply

For the GE scope of supply, the only TLAA was for the service life of the vessel. GE has determined that the corrosion allowance is adequate for the extended period of operation. Since this conclusion is consistent with industry operating experience, the staff finds that the TLAA for the vessel is acceptable.

4.3.4 Conclusion

The staff has reviewed the information in Section 4.3, “Corrosion Allowance” of the LRA. On the basis of the review, the staff concludes that the applicant has adequately evaluated the corrosion allowance TLAA as required by 10 CFR 54.21(c)(1).

4.4 Environmental Qualification of Electrical Equipment

The Plant Hatch 10 CFR 50.49 Environmental Qualification (EQ) Program has been identified as a TLAA for the purposes of license renewal. The TLAA aspect of EQ encompasses all long-lived equipment whether active or passive, and each equipment qualification file for a long-lived component documents a TLAA.

The applicant described its TLAA for Environmental Qualification of Electrical Equipment in Section 4.4, “Environmental Qualification of Electrical Equipment,” of the LRA. The staff reviewed this section of the LRA to determine whether the applicant provided adequate information to meet the requirements set forth in 10 CFR 54.21(c)(1) regarding an evaluation of EQ. The staff also reviewed Section 4.4.1 of the LRA to consider the applicant’s resolution of Generic Safety Issue (GSI) 168, “Environmental Qualification of Electrical Components.”

4.4.1 Summary of Technical Information in the Application

The Plant Hatch EQ TLAA evaluation implements 10 CFR 54.21 (c)(1) to demonstrate that (i) the analyses remain valid for the period of extended operation, (ii) the analyses have been projected to the end of the period of extended operation, or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. Following is a summary description of the EQ TLAA.

Scope of EQ Equipment

Based on a review of the Plant Hatch EQ documentation, the applicant identified electrical equipment important to safety that has a qualified life of at least 40 years, during which the electrical equipment can perform its intended functions during a loss-of-coolant accident (LOCA) or a high-energy line break (HELB) in the harsh environments of the containment and reactor building. The scope of equipment in the Plant Hatch EQ program is as follows:

- Safety-related (in accordance with the definition in 10 CFR 50.49(b), consistent with the Plant Hatch CLB) electrical equipment in a postulated harsh environment that is required to mitigate the consequences of the accident causing the harsh environment or whose subsequent failure can degrade safety systems or mislead the plant operator.

- Non-safety-related electrical equipment in a postulated harsh environment whose failure could impede a safety function or mislead the operator. The impact on emergency operation procedures should be considered in the failure analysis.

- Certain post-accident monitoring equipment located in a postulated harsh environment and designated as requiring qualification in the Regulatory Guide 1.97 section of Plant Hatch's response to Supplement 1 of NUREG-0737, "Clarification of TMI Action Plan Requirements."

EQ Process

The EQ process is controlled by the EQ Master List and the EQ procedures. The EQ Master List provides the following equipment information:

- plant tag number of the equipment
- the manufacturer and model or series number of the equipment
- the building, floor elevation, and specific location of the equipment
- the Qualification Data Package (QDP) which addresses qualification and maintenance of equipment

The EQ Installation/Maintenance Procedure Outline (I/MPO) specifically addresses the following:

- maintenance required to maintain equipment qualification

- qualified life of the equipment, any component part to be replaced, and the replacement interval (e.g., replace cover o-ring every 18 months)

- sealing of the equipment cable entrance to prevent moisture intrusion, as required

- installation and mounting configurations required to maintain qualification

- shelf life or storage requirements

- information on procuring and reordering equipment

Replacement Equipment

Prior to the expiration of the qualified life of a piece of EQ equipment, the Plant Hatch work management system generates a maintenance work order to alert plant personnel that the equipment is scheduled for replacement in the near future with the following available options:

- replace the existing component with an identical component

- replace the equipment with different equipment which is already evaluated under the EQ program

- replace the equipment with different equipment which is not currently evaluated under the EQ program (this option requires an equipment review, a function review, and an EQ review)

- reanalyze qualified life calculations to extend the qualified life if excess conservatism exists in the original qualified life calculation. Conservatism may exist in parameters such as the assumed ambient temperature of the equipment, an unrealistically low activation energy, or in the application of the equipment. The reanalysis is documented in the EQ central file. The guidelines in EPRI TR-104873, "Methodologies and Procedures to Optimize Environmental Qualification Replacement Intervals," are followed. Reanalysis is performed at Plant Hatch as follows:

    - Analytical Methods - The Arrhenius methodology is the thermal model used to reanalyze qualified life calculations. During normal operations, equipment is only subjected to ambient humidity levels (20-90%). Environmentally qualified equipment is typically sealed and cable insulation is protected from occasional inadvertent spray. Exposure to moisture from leaks is investigated on a case-by-case basis. The analytical method used for radiation reanalysis identified the 40-year radiation dose from the EQ criteria manual for the area where the equipment is installed, multiplied that value by the ratio of the evaluation period divided by 40 years (e.g., for license renewal 60 years/40 years, or 1.5), and added the applicable accident radiation dose to obtain the total integrated dose for the equipment. Plant Hatch has specifically assessed the impact of life extension from 40 to 60 years on the EQ radiation exposures for both units.

    - Data Collection and Reduction Methods - Reducing excess conservatism in the equipment service temperatures used in existing analyses is the chief purpose of reanalysis. Temperature data for a reanalysis is obtained from actual temperature measurements in the area around the equipment being reanalyzed. Temperature measurements can be obtained from monitors used for technical specification compliance, from other installed monitors, or from temperature sensors on specific components. The measurements can also be taken by plant operators during surveillance rounds. A representative number of temperature measurements is mathematically reduced to arrive at a temperature for the reanalysis. A reanalysis may use the actual calculated temperature, or may use the calculated temperature to show conservatism in the design temperature.

    - Underlying Assumptions - Conservatism in the EQ equipment qualification analyses has been maintained sufficiently to absorb environmental changes due to plant modifications and events. Major plant modifications or events of sufficient

duration (such as power uprates) to change temperature, pressure, and/or radiation values used in the underlying assumptions or in the EQ calculations are addressed in the design phase, prior to implementation of the plant modification, or operational change (the process by which changes to the underlying assumptions are made is discussed below under “Plant Environmental Changes.”)

- Acceptance Criteria and Corrective Actions - Adequate margin as described in IEEE Std. 323-1974 and the Division of Operating Reactor Guidelines, is maintained in all reanalyses, or adequate justification reducing margin is provided. If the reanalysis does not maintain adequate margin and less margin cannot be justified, the equipment qualification is not extended and the equipment is replaced as scheduled prior to the expiration of the existing qualification.

Refurbishment of Environmentally Qualified Electrical Equipment

Equipment in need of refurbishment is typically replaced with new equipment or previously refurbished equipment taken out of storage. The removed equipment is then discarded or refurbished and placed in storage. Qualified equipment is required to be refurbished before it can be put back in storage. Refurbishment is performed in a manner that preserves the equipment’s qualification. "Soft" items, such as gaskets, seals, and wires, which have a limited life, are typically replaced.

The manufacturer and model of replacement parts with an EQ-limited life are identified in the I/MPO, EQ maintenance procedures, and vendor manuals for environmentally qualified equipment. The documentation includes guidance on the shelf life of refurbished equipment.

Procurement of EQ Equipment

Procurement policies and criteria for environmentally qualified equipment are controlled by site procedures and the Nuclear Quality Assurance Program. Procurement of like-for-like replacement of environmentally qualified equipment is controlled so that the procured equipment is as good as, or better than, the original equipment. The procurement process also assures that applicable performance requirements and qualification criteria are met. The component's QDP contains procurement information such as the manufacturer or vendor, test reports to be referenced on the requisition, and equipment specifications.

Specifications for procurement are reviewed, and test plans are reviewed and approved prior to testing to assure compliance with the specifications. New test reports are evaluated and inserted into the QDP, and the EQ Master List is updated.

Plant Environmental Changes

Engineering Specification SS-2102-238, Revision 7, documents plant environmental conditions for both normal and accident conditions. The harsh environment areas of the plant for LOCAs, HELBs, and radiation are identified in accordance with the CLB. The Plant Hatch EQ central file contains temperature and pressure profiles for the various accident scenarios, including worst-case composite accident profiles for the harsh environments of the containment and reactor building. The central file also contains the supporting calculations for these accident profiles and total integrated radiation doses. All specifications, calculations, and other central file documents are controlled documents.

Measurements of critical parameters, such as containment temperatures for technical specifications, are taken on an ongoing basis. Changes in environmental parameters are reviewed when found or anticipated as a result of an impending design change. When a significant environmental change is identified, a review of the qualification of affected environmentally qualified equipment is performed and applicable changes are made to the equipment's qualified life and QDP documentation. The EQ calculations, specifications, and accident profiles are revised, as appropriate, to reflect the new operating conditions.

EQ Generic Safety Issue

GSI-168, "Environmental Qualification of Electrical Equipment," was developed to address environmental qualification of electrical equipment. The staff guidance to the industry (letter dated June 2, 1998 from NRC (Grimes) to NEI (Walters)) states:

- GSI-168 issues have not been identified to a point that a license renewal applicant can be reasonably expected to address these issues, specifically at this time; and

- An acceptable approach is to provide a technical rationale demonstrating that the CLB for EQ will be maintained in the period of extended operation.

For the purpose of license renewal, as discussed in the statement of considerations (SOC) (60 FR 22484, May 8, 1995), there are three options for addressing issues associated with a GSI:

- If the issue is resolved before the renewal application is submitted, the applicant can incorporate the resolution into the application.

- An applicant can submit a technical rationale that demonstrates that the CLB will be maintained through the period of extended operation until one or more reasonable options become available to adequately manage the effects of aging.

- An applicant can develop a plant-specific aging management program that incorporates a resolution to the aging issue.

To address issues associated with GSI-168, the applicant has chosen to pursue the second approach. The applicant will continue to manage the effects of aging in accordance with the CLB and considers the evaluation of the EQ TLAA in Section 4.4 of the LRA to be the technical rationale that demonstrates that the CLB will be maintained until some later point in the period of extended operation, when one or more reasonable options become available to adequately manage the effects of aging.

4.4.2 Staff Evaluation

In accordance with 10 CFR 54.21(c)(1), the staff reviewed Section 4.4 of the LRA to determine whether the applicant provided adequate information to meet the requirements that (i) the analyses remain valid for the period of extended operation; (ii) the analyses have been projected to the end of the period of extended operation; or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The staff also reviewed the treatment of GSI-168 in Section 4.4 of the LRA. After completing the initial review, the staff issued RAIs on July 28, 2000, and met with the applicant on August 23, 2000, to discuss RAIs 4.4-1 and 4.4-2 in the EQ TLAA area. The staff received the applicant's responses to the RAIs by letter dated October 10, 2000.

The applicant is using standard approved EQ methodologies and acceptance criteria, as defined by NRC Bulletin 79-10B, “Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors" (DOR Guidelines), including Supplements 1, 2, and 3; NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety-Related Electrical Equipment," Revision 1; 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants"; RG 1.89, " Environmental Qualification of Certain Electric Equipment Important to Safety for Nuclear Power Plants," Revision 1; various NRC generic letters and information notices; and NRC safety evaluation reports on EQ. The current actions for short-lived environmentally qualified equipment are also acceptable for long-lived EQ equipment. As discussed below, the staff concurs with the applicant’s EQ methodology.

The applicant is implementing 10 CFR 54.21(c)(1)(i), (ii), and (iii) for evaluating the EQ TLAA. The staff reviewed the following aspects of the applicant’s EQ TLAA methodology:

- Scope of EQ program
- EQ process
    - Original qualification basis
    - EQ master list
    - EQ maintenance
    - Replacement of equipment
    - Replace the existing equipment with identical equipment
    - Replace the equipment with different equipment currently evaluated under the EQ program
    - Replace the equipment with different equipment not currently evaluated under the EQ program
    - Reanalyze the qualified life calculation
    - Refurbishment of environmentally qualified equipment
    - Procurement of environmentally qualified equipment
    - Plant environmental changes

<u>TLAA Demonstration for Option 10 CFR 54.21(c)(1)(i)</u>

Section 4.4.5 of the LRA lists various commodity types based on Option (i) of 10 CFR 54.21(c)(1) whose analyses remain valid for the period of extended operation. In its response to RAI 4.4-1, the applicant provided thermal and radiation summaries for 38 commodity types that are based on Option (i). The staff reviewed the analyses and finds the demonstration of 10 CFR 54.21(c)(1)(i) for these commodity types to be acceptable for the period of extended operation.

<u>TLAA Demonstration for Option 10 CFR 54.21(c)(1)(ii)</u>

Section 4.4.5 of the LRA lists various commodity types based on Option (ii) of 10 CFR 54.21(c)(1) whose analyses have been projected to the end of the period of extended operation. During a meeting on August 23, 2000, the staff reviewed the EQ calculations for projecting the qualified lives of the following sample of commodity types to the end of the period of extended operation:

- Limitorque SB, SMB Actuators, AC Service

- General Electric F01 Electrical Penetration Assemblies

- Amphenol Type HN Plug Connectors
- States ZWM and NT Series Terminal Blocks
- Raychem Breakout/Scotchcast 9 Potting Compound
- AMP Special Ind. Insulated/Uninsulated Terminals and Splices
- Okonite Low/Medium Voltage Instrumentation, Control, and Power Cables
- Okonite T-95 Insulating and No. 35 Jacketing Tapes/Cement
- Anaconda Low Voltage Instrumentation, Control, and Power Cables
- GE RHR and Core Spray Pump Motors
- Brand-Rex Low Voltage Instrumentation, Control, and Power Cables and Internal Panel Wiring
- Conax Buffalo Electrical Penetration Assemblies
- Eaton (Samuel Moore) Instrumentation and Thermocouple Cables
- Reliance Motors FNA-6856 and 6857

Based on the staff's review of the applicant's thermal and radiation summaries and the EQ calculations that were reviewed during the August 23, 2000, meeting, the staff finds the demonstration of 10 CFR 54.21(c)(1)(ii) to be acceptable for the Option (ii) commodity types listed in Section 4.4.5 of the LRA.

TLAA Demonstration for the 10 CFR 54.21(c)(1)(iii) Option

Section 4.4.5 of the LRA lists various commodity types based on Option (iii) of 10 CFR 54.21(c)(1) on which the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. For Option (iii) commodity types whose qualified lives could not be extended significantly, the Plant Hatch EQ program and the associated site administrative controls have the necessary elements to ensure that the effects of aging on the intended function(s) of the qualified equipment will be adequately managed for the period of extended operation. For EQ components that cannot be qualified to the end of the period of extended operation, aging effects will continue to be managed in accordance with the current licensing basis, which requires that equipment be replaced or refurbished at the end of its qualified life unless ongoing qualification demonstrates that the item has additional life. The staff finds this approach to be an acceptable demonstration of 10 CFR 54.21(c)(1)(iii) for managing the effects of aging on environmentally qualified components for the period of extended operation.

GSI-168 Finding

The staff finds that the applicant's approach to resolving GSI-168 for license renewal (i.e., continuing to manage the effects of aging in accordance with the CLB until one or more reasonable options become available to adequately manage the effects of aging) is consistent with the June 2, 1998, staff guidance to industry.

4.4.3 Conclusion

The staff has reviewed the EQ TLAA information in Section 4.4 of the Plant Hatch LRA, the additional information provided in the August 23, 2000, meeting on EQ between the staff and the applicant, and the October 10, 2000, response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1), that, for TLAAs related to environmental qualification of electrical equipment, (i) the analyses remain valid for the period of extended operation, (ii) the analyses have been projected to the end of the period of extended operation, or (iii) the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. In addition, the staff finds the applicant's approach to resolving GSI-168 acceptable.

4.5 Containment Penetration Pressurization Cycles

In Section 4.5 of the LRA, the applicant described the time-limited effect of pressurization cycles on the design of containment penetrations. The staff reviewed this section of the LRA to determine whether the applicant has demonstrated that the effects of aging on the containment penetrations will be adequately managed during the period of extended operation, pursuant to10 CFR 54.21(c)(1).

4.5.1 Summary of Technical Information in the Application

The applicant identified one containment penetration structural analysis for Plant Hatch that assumed a number of pressurization cycles over a 40-year period. This calculation was determined to meet the definition of a TLAA, as stated in 10 CFR 54.3 and Section 4.1 of this SER. The applicant also stated that the architect-engineer performed a structural analysis to determine the acceptability of certain types of pipe-to-penetration welds using backing rings. The effects of the pressurization cycles on these calculations were stated as being minimal. The applicant also stated that the calculation had been extended to 60 years of operation without a change to plant equipment, based on Criterion (ii) of 10 CFR 54.21(c)(1).

4.5.2 Staff Evaluation

The staff reviewed the information provided in Section 4.5 of the LRA regarding fatigue analyses of containment penetrations, and concluded that additional information was needed to complete the staff review. The staff issued RAIs by letter dated July 28, 2000. By letter dated October 10, 2000, the applicant provided responses to the RAIs. The staff has evaluated the applicant's responses, as follows.

In RAI 4.5-1, the staff requested that the applicant identify the containment penetration whose structural analysis assumed a number of pressurization cycles for 40 years. The RAI requested the applicant to provide the penetration's location, the number of pressurization cycles it was assumed to undergo during the current licensing term, the actual cycles that have been experienced, and the number of cycles expected until the end of the extended period of

operation. Since containment penetrations also experience thermal cycling as a result of plant operation, the applicant was also requested to provide the number of thermal cycles for which this penetration had been evaluated. In addition, the applicant was also requested to provide a summary of the structural analysis which was performed to demonstrate the acceptability of the pipe-to-penetration welds using backing rings.

In its response, the applicant stated that the calculation applies to the Class B weld of the main steam penetration assembly to the containment, and justifies the use of a backing ring for that type and location of weld. Forty pressurization cycles to full design pressure were assumed in the calculation, which was revised to consider sixty pressurization cycles to full design pressure. The applicant stated that this assumption is conservative, and that the applicant had therefore demonstrated the acceptability of the analysis in accordance with 10 CFR 54.21(c)(1)(ii). In addition, the response indicated that the calculation applies to a Class B weld that is referenced in ASME Section III, N-415.1, 1968 Edition, “Vessels not Requiring Analysis for Cyclic Operation.” Reference to N-415.1 indicates that the stresses due to the pressurization cycles were found to meet the limiting stress criterion which does not require a fatigue analysis under the provisions of this section. By letter dated January 24, 2001, the applicant submitted additional (proprietary) information, which provided justification for concluding that thermal cycling of the penetration assembly does not represent a significant loading condition requiring fatigue analysis under the provisions of ASME Section III, N-415.1. The staff has reviewed this information and concludes that the applicant has demonstrated that this TLAA for the containment penetrations will remain valid for the period of extended operation. The staff therefore finds the response to RAI 4.5-1 acceptable and considers this concern resolved.

In RAI 4.5-2, the applicant was requested to provide information regarding the effect of thermal cycling on the drywell and torus vent line penetrations and penetration bellows (including vent line bellows), and dissimilar metal welds resulting from reactor mode changes and other transients, pressurization pulses during safety relief valve (SRV) discharges, and pressure cycles during leak testing. In its response, the applicant stated that the information requested in this RAI pertaining to containment torus penetrations is summarized in the design analysis addressing fatigue in the torus for the license renewal period (”Hatch Units 1 and 2 Torus Fatigue Analysis Report, REA HT-98674 Response”, Revision 0, Southern Company Services, Inc., Nuclear Engineering and Regulatory Support, April 1999). In Section 4.2.4 of the LRA, the applicant stated that the CLB fatigue calculations for the torus structure were reviewed, and on this basis determined that a new analysis was necessary to address fatigue in the torus for the extended license term. The analysis required an extensive and detailed review of pressure and thermal transients for the torus. By letter dated January 24, 2001, the applicant provided a (proprietary) summary of this analysis. The staff has reviewed this information and concludes that the applicant has demonstrated satisfactorily that the fatigue adequacy of the Unit 1 and Unit 2 torus penetrations under the CLB transient operating conditions will be maintained during the period of extended operation. The applicant also addressed the fatigue adequacy of the drywell penetrations by referencing EPRI report TR-103840 “BWR Containments License Renewal Industry Report; Revision 1” July 1994, which indicates that fatigue of these penetrations subject to the CLB transient operating conditions will be minimal for the period of extended operation. The staff finds the response to RAI 4.5-2 acceptable, and considers this concern resolved.

In RAI 4.5-3 the applicant was requested to provide a list of the containment penetrations with pipe-to-penetration welds. In RAI 4.5-4, the applicant was requested to provide justification for not performing fatigue TLAAs on containment penetrations with pipe-to-penetration welds susceptible to combined pressurization cycles and plant operational thermal expansion cycles.

The applicant stated in its response that the Unit 1 and Unit 2 current licensing bases were reviewed, and that no specific analyses on this subject were found that met the criteria of 10 CFR 54.3 for a fatigue TLAA. However, the applicant indicated that fatigue of these welds was addressed under the overall response to RAI 4.5-2. The staff concurs with the applicant's response, and considers the concerns stated in RAIs 4.5-3 and 4.5-4 resolved.

4.5.3 Conclusion

The staff has reviewed the information in Section 4.5 "Containment Penetration Pressurization Cycles" of the LRA, the applicant's responses to the staff's RAIs, and the information provided to the staff by letter dated January 24, 2001. On the basis of this review, and pursuant to 10 CFR 54.21(c)(1), the staff concludes that the applicant has adequately evaluated the containment penetration pressurization cycles TLAA.

4.6 Time Limited Aging Analyses for the Reactor Vessel

4.6.1 Summary of Technical Information in the Application

Neutron Irradiation Embrittlement

Neutron irradiation causes a decrease in the Charpy upper-shelf energy (USE) and an increase in the adjusted reference temperature (ART) of the reactor pressure vessel (RPV) beltline materials. The ART impacts the plant's pressure-temperature (P-T) limits and RPV integrity evaluations. BWRVIP-74 has performed integrity evaluations of BWR RPV circumferentially oriented welds and BWR RPV axially oriented welds. Therefore, in order for BWRs to demonstrate that neutron embrittlement does not significantly impact RPV integrity during the license renewal term, BWRs must evaluate the impact of neutron irradiation on the Charpy USE, P-T limits, RPV circumferential welds, and RPV axial welds.

Charpy (USE)

By letter dated April 30, 1993, the Boiling Water Reactor Owner's Group (BWROG) submitted a topical report entitled "10 CFR 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to document that BWR RPVs could meet the margins of safety against fracture equivalent to those required by Appendix G of the ASME Code for Charpy USE values less than 50 ft-lb. General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999. This updated analysis incorporates the effects of irradiation for 54 effective full-power years (EFPY), which corresponds to 60 years of operation at 90 percent power. The updated analysis determined that the generic materials considered will maintain the margins for USE required by 10 CFR Part 50 Appendix G. GE reviewed the updated generic analyses with respect to applicability for the Plant Hatch license renewal term. This review is documented in an evaluation performed by GE in GENE B11-00827-00-01, "Plant Hatch Units 1 and 2 Reactor Pressure Vessel Pressure/Temperature Limits License Renewal Evaluation," General Electric Company, March 1999. GE determined that the generic analyses are applicable and that, for 54 EFPY, the critical materials would retain sufficient USE to satisfy 10 CFR 50 Appendix G requirements.

P-T Limits

GE performed a plant-specific analysis of the ART for Plant Hatch in GENE B11-00833-00-01, "Plant Hatch Reactor Pressure Vessel Aging Management Report," General Electric Company, November 1999, using the criteria defined in EPRI TR-113596. The GE analysis for Plant Hatch considers the effect of neutron embrittlement for 54 EFPY. The analysis includes new sets of reactor operating pressure and temperature curves. The results of the analysis indicate that for both units, the ART will be less than 200 °F.

Circumferential RPV Weld Inspection Relief

The BWRVIP provided the technical bases supporting the elimination of RPV circumferential welds from the inservice inspection programs for BWRs in EPRI TR-113596. These technical bases are approved for the current license term and are applicable to Plant Hatch.

Appendix E of the NRC's Safety Evaluation Report (SER), "Final Safety Evaluation of the BWR Vessel and Internals Project BWRVIP-05 Report (TAC No. M93925)," USNRC, July 28, 1998, documents an evaluation of the impact of license renewal from 32 EFPY to 64 EFPY on the conditional probability of vessel failure. The SER reports that the frequency of cold over pressurization events results in a total vessel failure probability of approximately 5×10^{-7}. The SER conservatively evaluates an operating period of 10 EFPY greater than what is realistically expected for a 20-year license renewal term, i.e., 48 to 54 EFPY. Therefore, this analysis provides a basis for BWRVIP-05 to be approved as a technical alternative from the current inservice inspection requirements of ASME Section XI for volumetric examination of the circumferential welds as they may apply in the license renewal period.

Axially Oriented RPV Welds

The staff's SER, contained in a letter dated March 7, 2000, to Carl Terry, BWRVIP Chairman, discusses the staff's concern related to RPV failure frequency for axial welds and the BWRVIP's analysis of the RPV failure frequency of axial welds. The SER indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution and location described in the SER. Since the BWRVIP analysis was generic, the applicant provided plant-specific information in response to RAI 4.6-2 to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report.

4.6.2 Staff Evaluation

Neutron Irradiation Embrittlement

Appendix G to 10 CFR Part 50 specifies fracture toughness requirements for ferritic materials of the pressure-retaining components of the reactor coolant pressure boundary of light water nuclear power reactors and provides adequate margins of safety during any condition of normal operation, including anticipated operational occurrences and system hydrostatic tests, to which the pressure boundary may be subjected over its service lifetime. For the RPV, this appendix requires an evaluation of the Charpy USE and an evaluation of the ART to determine pressure-temperature limits for the RPV. Neutron irradiation causes a decrease in the Charpy USE and an increase in the adjusted reference temperature of the RPV beltline materials. The staff's evaluation of the impact of irradiation on the Charpy USE, pressure-temperature limits, RPV

circumferential weld, and RPV axial weld integrity analysis is discussed in this section. Since each of these evaluations are dependent upon the neutron fluence received by the RPV, neutron fluence will also be discussed in this section.

Charpy (USE)

Section IV.A.1a. of Appendix G to 10 CFR Part 50 requires, in part, that RPV beltline materials must have Charpy USE in the transverse direction for base metal and along the weld for weld material of no less than 50 ft-lb (68J), unless it is demonstrated in a manner approved by the Director, Office of Nuclear Reactor Regulation, that lower values of Charpy USE will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

By letter dated April 30, 1993, the Boiling Water Reactor Owner's Group (BWROG) submitted a topical report entitled "10 CFR 50 Appendix G Equivalent Margins Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels," to document that BWR RPVs could meet the margins of safety against fracture equivalent to those required by Appendix G of the ASME Code for Charpy USE values less than 50 ft-lb. In a letter dated December 8, 1993, the staff concluded that the topical report demonstrates that the evaluated materials have the margins of safety against fracture equivalent to Appendix G of the ASME Code, in accordance with Appendix G of 10 CFR Part 50. In this report, the BWROG derived through statistical analysis the initial USE values for materials that originally did not have documented Charpy USE values. Using these statistically derived Charpy USE values, the BWROG predicted the end-of life (40 years of operation) USE values in accordance with Regulatory Guide 1.99, Revision 2 (RG 1.99, Rev. 2). According to this RG, the decrease in USE is dependent upon the amount of copper in the material and the neutron fluence predicted for the material. The BWROG analysis determined that the minimum allowable Charpy USE in the transverse direction for base metal and along the weld for weld metal was 35 ft-lb.

General Electric (GE) performed an update to the USE equivalent margins analysis, which is documented in EPRI TR-113596, "BWR Vessel and Internals Project BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," BWRVIP-74, September 1999. EPRI TR-113596 provides a bounding Charpy USE for BWR plants for 54 effective full-power years (EFPY), the bounding analysis for Plant Hatch-type plants (BWR/4) indicates that at 54 EFPY the Charpy USE in the transverse direction for plates would be at least 45 ft-lb and the Charpy USE for the non-Linde 80 submerged arc welds (SAWs) would be at least 43 ft-lb. Since these values are greater than the minimum allowable Charpy USE of 35 ft-lb, these materials would have margins of safety against fracture equivalent to Appendix G of the ASME Code. Since this was a generic analysis, the applicants should provide plant-specific information to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report.

The analysis in EPRI TR-113596 utilized an unirradiated Charpy USE in the longitudinal direction of 91 ft-lb for BWR/3-6 plates and 70.5 ft-lb for non-Linde 80 submerged arc welds. The value for the plates is the lowest value from the database and is less than the lower 95/95 confidence value. The value for the non-Linde 80 submerged arc welds is the value corresponding to the lower 95/95 confidence value. Since these values are statistically determined with at least 95/95 confidence, the values may be used in the evaluation of Charpy USE.

The analysis in EPRI TR-113596 determined the reduction in the unirradiated Charpy USE resulting from neutron radiation using the methodology in RG 1.99, Revision 2. Using this methodology and using a correction factor of 65% for conversion of the longitudinal properties to

transverse properties, the lowest irradiated Charpy USE at 54 EFPY for all BWR/3-6 plates is projected to be 45 ft-lb. The correction factor for specimen orientation in plates is based on NRC Branch Technical position MTEB 5-2. Using the RG methodology, the lowest irradiated Charpy USE at 54 EFPY for BWR non-Linde 80 submerged arc welds is projected to be 43 ft-lb. EPRI TR-113596 indicates that the percent reduction in Charpy USE for the limiting BWR/3-6 plates and BWR non-Linde 80 submerged arc welds are 23.5 percent and 39 percent, respectively. To demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report, the applicant should demonstrate that the percent reduction in Charpy USE for its beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for its surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.

In response to RAI 4.6-3 and in Section E of the LRA, the applicant provided plant-specific information necessary to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report. The applicant indicates that predicted reduction in Charpy USE at 54 EFPY for the limiting plates in Units 1 and 2 are 19 percent and 15 percent, respectively. The predicted reduction in Charpy USE at 54 EFPY for the limiting welds in Units 1 and 2 are 33 percent and 24 percent, respectively. The applicant indicates that the percent reduction in Charpy USE for its surveillance weld and plate are less than the values projected using the methodology in RG 1.99, Revision 2. The staff has reviewed the information provided by the applicant and has determined that the percent reduction in Charpy USE for the beltline materials and the surveillance materials meet the criteria specified in EPRI TR-113596. In addition, the staff has also determined that the materials and surveillance data reported by the applicant is consistent with data contained in the Reactor Vessel Integrity Data Base (RVID). The RVID is a data base maintained by the staff, which contains a summary of all the relevant materials data submitted by all applicant's in their evaluations of reactor vessel integrity. Since the Plant Hatch beltline material and surveillance weld and plate meet the specified criteria, the Plant Hatch beltline materials will meet the margins of safety against fracture equivalent to those required by Appendix G of the ASME Code and therefore, meet the Charpy USE requirements of Appendix G, 10 CFR Part 50 at 54 EFPY.

P-T Limits

The staff evaluated the P-T limit curves based on the following NRC regulations and guidance: 10 CFR 50, Appendix G; Generic Letter (GL) 88-11, "NRC Position on Radiation Embrittlement of Reactor Vessel Materials and It's Impact on Plant Operations"; GL 92-01, "Reactor Vessel Structural Integrity, " Revision 1; GL 92-01, Revision 1, Supplement 1; Regulatory Guide (RG) 1.99, Rev. 2; and Standard Review Plan (SRP) Section 5.3.2. GL 88-11 advised applicants that the staff would use RG 1.99, Rev. 2, to review P-T limit curves. RG 1.99, Rev. 2, contains methodologies for determining the increase in transition temperature and the decrease in upper-shelf energy resulting from neutron radiation. GL 92-01, Rev. 1, requested that applicants submit their RPV data for their plants to the staff for review. GL 92-01, Rev. 1, Supplement 1, requested that applicants provide and assess data from other applicants that could affect their RPV integrity evaluations. These data are used by the staff as the basis for the staff's review of P-T limit curves. Appendix G to 10 CFR Part 50 requires that P-T limit curves for the RPV be at least as conservative as those obtained by applying the methodology of Appendix G to Section XI of the ASME Code.

SRP Section 5.3.2 provides an acceptable method of determining the P-T limit curves for ferritic materials in the beltline of the RPV based on the linear elastic fracture mechanics (LEFM)

methodology of Appendix G to Section XI of the ASME Code. The basic parameter of this methodology is the stress intensity factor K_I, which is a function of the stress state and flaw configuration. Appendix G requires a safety factor of 2.0 on stress intensities resulting from reactor pressure during normal and transient operating conditions, and a safety factor of 1.5 for hydrostatic testing curves. The methods of Appendix G postulate the existence of a sharp surface flaw in the RPV that is normal to the direction of the maximum stress. This flaw is postulated to have a depth that is equal to 1/4 thickness (1/4T) of the RPV beltline thickness and a length equal to 1.5 times the RPV beltline thickness. The critical locations in the RPV beltline region for calculating heatup and cooldown P-T curves are the 1/4T and 3/4 thickness (3/4T) locations, which correspond to the maximum depth of the postulated inside surface and outside surface defects, respectively.

The Appendix G to the ASME Code methodology requires that applicants determine the adjusted reference temperature (ART or adjusted RT_{NDT}). The ART is defined as the sum of the initial (unirradiated) reference temperature (initial RT_{NDT}), the mean value of the adjustment in reference temperature caused by irradiation (ΔRT_{NDT}), and a margin (M) term.

The ΔRT_{NDT} is a product of a chemistry factor and a fluence factor. The chemistry factor is dependent upon the amount of copper and nickel in the material and may be determined from tables in RG 1.99, Rev. 2, or from surveillance data. The fluence factor is dependent upon the neutron fluence at the maximum postulated flaw depth. The margin term is dependent upon whether the initial RT_{NDT} is a plant-specific or a generic value and whether the chemistry factor (CF) was determined using the tables in RG 1.99, Rev. 2, or surveillance data. The margin term is used to account for uncertainties in the values of the initial RT_{NDT}, the copper and nickel contents, the fluence and the calculational procedures. RG 1.99, Rev. 2, describes the methodology to be used in calculating the margin term.

Section E of the LRA contains P-T limit curves for 54 EFPY. In addition, intermediate curves for 36, 40, 44, and 48 EFPY for Unit 1 have been provided, due to the expected irradiation shift for the Unit 1 vessel. The applicant proposes to include these P-T limits in the Plant Hatch Technical Specifications. Tables 3-1 and 3-2 in Enclosure 3 to Section E contains the applicant's evaluation of the ART for all RPV beltline materials in Plant Hatch Units 1 and 2 at 54 EFPY. Tables containing ART for all RPV beltline materials in Unit 1 at 36, 40, 44, and 48 EFPY were not provided. Hence, the curves for 36, 40, 44, and 48 EFPY for Unit 1 could not be evaluated. Therefore, at this time, the staff can only evaluate the curves applicable for 54 EFPY.

The material with the highest ART at 54 EFPY in the RPV beltlines of Unit 1 is plate G-4804-2. This plate contains 0.13 percent copper and 0.70 percent nickel which, according to RG 1.99, Revision 2 corresponds to a chemistry factor of 93.5. This chemistry factor was increased by a factor of 2.62 based on the test results from the reactor vessel materials surveillance program. This results in a chemistry factor for this plate of 245 (93.5 x 2.62). The neutron fluence at the 1/4T location for this plate at 54 EFPY is 2.51E18 n/cm^2, which corresponds to a fluence factor of 0.625. The product of this fluence factor and a chemistry factor of 245 results in a ΔRT_{NDT} at 54 EFPY of 153.2^o F. Since the initial RT_{NDT} for this plate is -20^o F and the margin term is 34^o F, the ART for this plate at 54 EFPY is 167.2^o F.

The material with the highest ART at 54 EFPY in the RPV beltlines of Plant Hatch Units 1 and 2 is plate G-6603-2 in Unit 1. This plate contains 0.083 percent copper and 0.58 percent nickel, which according to RG 1.99, Revision 2, corresponds to a chemistry factor of 51. This chemistry factor was determined using Table 2 of RG 1.99, Revision 2, since no surveillance data exists

for this material. The neutron fluence at the 1/4T location for this plate at 54 EFPY is 1.67E18 n/cm^2 , which corresponds to a fluence factor of 0.527. The product of this fluence factor and a chemistry factor of 51 results in a ΔRT_{NDT} at 54 EFPY of 26.9^o F. Since the initial RT_{NDT} for this plate is 24^o F and the margin term is 26.9^o F, the ART for this plate at 54 EFPY is 77.8^o F.

The staff confirmed that the P-T limit curves for Plant Hatch Unit 1 and Unit 2 at 54 EFPY meet the requirements of Appendix G , 10 CFR Part 50, when the ART is 167.2^o F and 77.8^o F, respectively. Since the P-T limit curves at 54 EFPY meet the requirements of Appendix G, 10 CFR Part 50, the applicant has demonstrated that the Plant Hatch RPV can operate during the license renewal period and satisfy the requirements of Appendix G, 10 CFR Part 50. In the LRA, the applicant provided Section E which proposed a change to the Unit 1 and Unit 2 technical specifications in support of extended plant operation. Pressure-temperature operating limits based on the effects of irradiation on the core beltline up to 32 EFPY were incorporated at the time of submittal of the LRA. Subsequently, the applicant submitted its annual update to the LRA, dated December 15, 2000. In the update, the applicant removed the proposed change to the technical specifications because SNC has separately requested and received amendments to the technical specifications that incorporate changes to the pressure-temperature operating limits. However, Enclosure 3 to LRA Section E is retained since it supports certain reactor vessel TLAA issues. Those portions of Enclosure 3 specifically addressing the pressure-temperature limits are superseded by the separate licensing action taken by NRC in issuing Amendments 222 and 163 to the Unit 1 and Unit 2 operating licenses, respectively.

Circumferential RPV Weld Inspection

Sections 4.6.3 and A.1.17.1 of the LRA discuss ultrasonic inspection of the Plant Hatch RPV circumferential welds. Section A.1.17.1 of the LRA indicates that Plant Hatch will use an approved technical alternative in lieu of ultrasonic testing of RPV circumferential shell welds. The technical alternative is discussed in the staff’s final SER of the BWR Vessel and Internals Project BWRVIP-05 Report, which is contained in a July 28, 1998 letter to Carl Terry, BWRVIP Chairman. In its July 28 letter, the staff concludes that since the failure frequency for circumferential welds in BWR plants are significantly below the criteria specified in RG 1.154, “Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors,” and the core damage frequency (CDF) of any BWR plant, and that continued inspection would result in a negligible decrease in an already acceptably low value, elimination of the ISI for RPV circumferential welds is justified. The Staff’s letter indicates BWR applicants may request relief from inservice inspection requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds by demonstrating: (1) at the expiration of the license, the circumferential welds satisfy the limiting conditional failure probability for circumferential welds in the evaluation, and (2) they have implemented operator training and established procedures that limit the frequency of cold over-pressure events to the amount specified in the report. The letter indicated that the requirements for inspection of circumferential RPV welds during an additional 20 year license renewal period will be reassessed, on a plant specific basis, as part of any BWR license renewal application.

Section A.4.5 of Report BWRVIP - 74 indicates that the staff’s SER conservatively evaluated BWR RPV’s to 64 effective full power years (EFPY), which is 10 EFPY greater than what is realistically expected for the end of the license renewal period. Since this was a generic analysis, the applicant must provide plant-specific information to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the report.

In response to RAI 4.6-1, the applicant indicates that procedures and training used to limit cold over-pressure events during the license renewal period will be the same as those approved by the NRC when Plant Hatch requested the BWRVIP-05 technical alternative be used for the current term. In addition, the applicant compared the mean RT_{NDT} for Combustion Engineering fabricated welds from the staff's July 28, 1998 SER to the mean RT_{NDT} of the circumferential welds in Plant Hatch Units 1 and 2 at 54 EFPY. The mean RT_{NDT} values in the staff SER were values determined for the limiting BWR RPVs fabricated by Combustion Engineering, Babcock and Wilcox, and Chicago Bridge and Iron. Since the Plant Hatch RPVs were fabricated by Combustion Engineering, the results from the staff SER are applicable to Plant Hatch. However, the mean RT_{NDT} values projected for the circumferential welds at Plant Hatch were calculated using the neutron fluence at the 1/4T location and included a margin term. The mean RT_{NDT} in the staff SER was determined using the neutron fluence at the clad/weld metal interface and did not include a margin term. In a letter dated January 31, 2001, the applicant revised its analysis based on the projected neutron fluence at the clad/weld interface and did not include a margin term when calculating the mean RT_{NDT}. The mean RT_{NDT} of the circumferential welds in Hatch at 54 EFPY are less than the value for Combustion Engineering vessel (using Combustion Engineering Owners Group chemistries) at 32 EFPY and 64 EFPY, which indicates the Plant Hatch circumferential welds will be less embrittled than the Combustion Engineering vessel in the NRC staff analysis at 32 EFPY and 64 EFPY. The staff SER indicates that the conditional failure probabilities for Combustion Engineering vessel at 32 EFPY and 64 EFPY were 6.34E-5 and 4.38.34E-4, respectively. Since the Hatch circumferential welds will be less embrittled than the Combustion Engineering vessel analyzed in the staff's SER, the conditional failure probability for Hatch RPVs will be less than the values specified in the staff's SER for circumferential welds. Therefore, the applicant has demonstrated compliance with the criteria in the July 28, 1998 letter to Carl Terry and has justified relief from the inservice inspection requirements of 10 CFR 50.55a(g) for volumetric examination of circumferential RPV welds during the license renewal period.

<u>Axially Oriented RPV Welds</u>

In its July 28, 1998 letter to Carl Terry, BWRVIP Chairman, the staff also identified a concern about the failure frequency of axially oriented welds in BWR RPVs. In a response to this concern, the BWRVIP provided evaluations of axial weld failure frequency in letters dated December 15, 1998 and November 12, 1999. The staff's evaluation of these analyses is contained in a March 7, 2000 letter to Carl Terry. The SER that is enclosed in the March 7, 2000 letter indicates that the RPV failure frequency due to failure of the limiting axial welds in the BWR fleet at the end of 40 years of operation is below 5×10^{-6} per reactor year, given the assumptions on flaw density, distribution and location described in the SER. Since the results apply only for the initial 40-year license period of BWR plants, applicants for license renewal must provide plant-specific information applicable to 60 years of operation.

The BWRVIP identified Clinton and Pilgrim as the reactor vessels with the highest mean RT_{NDT} in the BWR fleet. The staff confirmed this conclusion in its SER by comparing the information contained in the BWRVIP analysis and the information contained the RVID for all BWR RPV axial welds. The staff performed analyses of the Clinton and Pilgrim plants. The results from the staff calculations are provided in Table 1. The staff calculations used the basic input information for Pilgrim, with three different assumptions for the initial RT_{NDT}. The calculations of the actual Pilgrim condition used the docketed initial RT_{NDT} of -48°F and a mean RT_{NDT} of 68°F. A second calculation, listed as "Mod 1" in Table 1, is consistent with the BWRVIP calculations, with an

initial RT_{NDT} of 0°F and a mean RT_{NDT} of 116°F. A third calculation, with an initial RT_{NDT} of -2°F and a mean RT_{NDT} of 114°F, was chosen to identify the mean value of RT_{NDT} required to provide a result which closely matches the RPV failure frequency of 5 x 10^{-6} per reactor-year.

Table 1: Comparison of Results from Staff and BWRVIP

Plant	Initial RT_{NDT} (°F)	Mean RT_{NDT} (°F)	Vessel Failure Freq.	
			Staff	BWRVIP
Clinton	-30	91	2.73E-6	1.52E-6
Pilgrim	-48	68	2.24E-7	-------
Mod 1 *	0	116	5.51E-6	1.55E-6
Mod 2 **	-2	114	5.02E-6	-------

* A variant of Pilgrim input data, with initial RT_{NDT} = 0°F.
** A variant of Pilgrim input data, with initial RT_{NDT} = -2°F.

The applicant provided plant-specific information in response to RAI 4.6-2 to demonstrate that the Plant Hatch beltline materials meet the criteria specified in the SER. The mean RT_{NDT} for the Plant Hatch axial welds were not compared to the mean RT_{NDT} in Table 1. The mean RT_{NDT} was compared to the mean RT_{NDT} for axial welds in the staff's July 28, 1998 SER. The SER in the March 7, 2000 letter supercedes the analysis in the July 28, 1998 letter. In a letter dated January 31, 2001, the applicant revised its analysis to compare the mean RT_{NDT} for the Plant Hatch axial welds to the mean RT_{NDT} for Pilgrim Mod 2 in Table 1, above. The mean RT_{NDT} of the axial welds in Hatch at 54 EFPY was 114°F. This value is less than the value for Pilgrim Mod 2 in Table 1, which indicates the Hatch axial welds at 54 EFPY will be less embrittled than the axial welds for the Pilgrim Mod 2 analysis performed by the staff in its March 7, 2000 letter. Since the Plant Hatch axial welds will be less embrittled than the axial welds for the Pilgrim Mod 2 analysis performed by the staff in its March 7, 2000 letter, the conditional failure probability for Hatch RPVs will be less than 5 x 10^{-6} per reactor-year a 54 EFPY. Therefore, the applicant has demonstrated compliance with the criteria in the staff's March 7, 2000 letter.

Neutron Fluence of the RPV

The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The neutron fluences for the Plant Hatch units were calculated using General Electric methodology documented in surveillance capsule reports GE-NE-B1100691-01R1 (March 1997) and SASR 90-104 (May1991). These neutron fluences were determined by taking the fluence at 32 EFPY associated with the approved extended power uprate and adding to it the fluence that would accumulate during an additional 22 EFPY of operation at the flux associated with the extended power uprate conditions. The extended power uprate was approved in a letter to H. L. Sumner, Jr. dated October 22, 1998; therefore, the neutron fluences documented in the LRA are acceptable at this time.

4.6.3 Conclusions

The staff has reviewed the information in Section 4.6, “Reactor Vessel TLAAs” of the LRA and the applicant’s responses to the staff’s RAIs. On the basis of this review, the staff concludes that the applicant has adequately evaluated the reactor vessel TLAA as required by 10 CFR 54.21(c)(1).

4.7 Main Steam Isolation Valves Operating Cycles

4.7.1 Introduction

The applicant described its evaluation related to main steam isolation valve operating cycles in Section 4.7, “Main Steam Isolation Valves Operating Cycles,” of the LRA. The staff reviewed this section of the LRA to determine whether the applicant has adequately evaluated the TLAA as required by 10 CFR 54.21(c).

4.7.2 Summary of Technical Information in Application

The Plant Hatch FSARs contain statements with regard to the design of the MSIVs for the current license term. The Unit 2 FSAR, Section 5.5.5.1, states the following (with a similar reference in the Unit 1 FSAR, Section 4.6.3):

> “The design objective for the valve is a minimum 40-year service at the specified operating conditions. Operating cycles are estimated to be 100 cycles per year during the first year and 50 cycles per year thereafter.”

The applicant further stated that the FSAR statement refers to mechanical cycles of the valve. Cycling of the valve will lead to wear of the valve disc and valve seat. The wear will accumulate over time (2050 cycles are assumed in the FSAR statement for 40 years). The statement therefore meets the criteria of a TLAA. However, this type of wear due to operation of the valve will lead to performance degradation, that can be discovered through normal leakage monitoring testing. Excessive leakage would lead to refurbishment or repair of the valve set and disc, as necessary. Once the maintenance is performed, the service life of the valve is restored. Since the aging effects can be readily discovered through normal Technical Specification surveillance testing and repairable maintenance, the TLAA is demonstrated through Criterion (iii) of 10 CFR 54.21(c)(1).

4.7.3 Staff Evaluation

As described above, the applicant dispositioned this TLAA through Criterion (iii) of 10 CFR 54.21(c)(1). Under this disposition option, the applicant should demonstrate that the effects of aging on the components’ intended functions will be adequately managed consistent with the CLB for the period of extended operation. In addition, the FSAR supplement for the facility should contain a summary description of the programs and activities for managing the effects of aging and the evaluation of the TLAA for the period of extended operation.

In RAI 4.7-1, dated July 28, 2000, the staff requested the applicant to provide information as described in 10 CFR 54.21(c)(1)(iii). The applicant responded to this RAI in its letters dated October 10, 2000 and January 31, 2001. The applicant stated that at the time of the LRA submittal, GE had been unable to fully determine the basis for the MSIV cycles in the FSAR. Therefore, as a conservative measure, the applicant identified the MSIV cycles in the FSAR as a

TLAA. Since that time, GE has determined that the number is derived from a specification, not from a calculation or analysis, as discussed in the Rule. On the basis of this confirmation from GE, the applicant has now determined that the MSIV cycles do not constitute a TLAA. The applicant also noted that, outside the scope of license renewal, the MSIVs are tested extensively as part of existing technical specification requirements because the valves are within the purview of the maintenance rule, and are being maintained consistent with the requirements of the maintenance rule. The applicant noted that the MSIVs have extensive testing programs that implement containment isolation testing and valve stroking requirements contained in Technical Specification 3.6.1.3. There are also inspection procedures to address the wear of the stellite faces. The MSIVs are periodically disassembled and refurbished. The solenoid valves and limit switches on the valves are also routinely replaced or completely refurbished to address environmental qualification requirements. In addition, there are other repetitive tasks, such as replacing the actuator hydraulic fluid every 54 months and inspecting the wiring every 36 months. In addition, the applicant stated that because these valves are periodically tested and refurbished, as necessary, GE has indicated that it is appropriate to restore the valve service life when valve internals are refurbished. Based on this supporting information, even if the assumption were made that the FSAR text constituted a *de facto* TLAA not directly supported by a calculation or analysis, the periodic restoration of the valve service life results in the supposed TLAA failing the criterion that the calculation or analysis be relevant to making a safety-related determination. The applicant further noted that although the MSIV cycles do not constitute a TLAA as presented in the LRA, the MSIV valve bodies are in scope for license renewal and are subject to an AMR.

4.7.4 Conclusion

The staff has reviewed the information in Section 4.7, “Main Steam Isolation Valves Operating Cycles” of the LRA and the applicant’s responses to the staff’s RAI. On the basis of this review, the staff concludes that the applicant’s responses are reasonable and sufficient for concluding that MSIVs operating cycles do not constitute a TLAA and are, therefore, acceptable.

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The Advisory Committee on Reactor Safeguards (ACRS) will review the 10 CFR Part 54 portion of the Edwin I. Hatch Nuclear Plant license renewal application. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this report is issued. Southern Nuclear Operating Company, Inc., and the staff will meet with the subcommittee and the full committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the Plant Hatch, LRA and SER, the full committee will issue a report discussing the results of its review. This report will be included in an update to this SER. The staff will address any issues and concerns identified in that report.

6 CONCLUSIONS

The staff reviewed the Edwin I. Hatch Nuclear Plant, Units 1 and 2, license renewal application in accordance with Commission regulations and the NRC draft “Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,” dated September 1997. In 10 CFR 54.29, the staff identifies the standards for issuance of a renewed license.

On the basis of its evaluation of the application as discussed above, the staff has determined that, on favorable resolution of the open items identified in Section 1.4 of this safety evaluation report, it will be able to conclude that the requirements of 10 CFR 54.29(a) have been met.

The staff notes that any requirements of subpart A of 10 CFR Part 51 will be documented in the final plant-specific supplement to the Generic Environmental Impact Statement. Should the resolution of subpart A of 10 CFR Part 51 be favorable, the staff will be able to conclude that the requirements of 10 CFR 54.29(b) have been met.