Template OCIO-032

NUREG-1723

Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3

Docket Nos. 50-269, 50-270 and 50-287

U.S. Nuclear Regulatory Commission
Office of Nuclear Reactor Regulation
Washington, DC 20555-0001

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Manuscript Completed: March 2000
Date Published: March 2000

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Oconee Nuclear Station (ONS), Unit Nos. 1, 2, and 3 license renewal application (LRA) by the U.S. Nuclear Regulatory Commission (NRC) staff. By letter dated July 6, 1998, Duke Energy Corporation (Duke) submitted the license renewal application for the ONS in accordance with Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54). Duke is requesting renewal of the operating licenses issued under Section 104 of the Atomic Energy Act of 1954, as amended, for the ONS, Unit Nos. 1, 2, and 3 (license numbers DPR-38, DPR-47, and DPR-55, respectively) for a period of 20 years beyond the current expiration dates: midnight, February 6, 2013, for Unit 1; midnight, October 6, 2013, for Unit 2; and midnight, July 19, 2014, for Unit 3.

The ONS is located in Oconee County in northwestern South Carolina on the shores of Lake Keowee. The three-unit nuclear station was constructed during the period from 1967 to 1974. Each unit consists of a Babcock and Wilcox (B&W) pressurized-water reactor nuclear steam supply system designed to generate 2568 MW thermal, or approximately 860 MW electric.

On the basis of its evaluation of the LRA, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis for the ONS, Unit Nos. 1, 2, and 3 during the period of extended operation.

CONTENTS

SUMMARY

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

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

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

The NRC also established requirements for a license renewal environmental report in 10 CFR Part 51. Those requirements establish the scope of a review of environmental impacts, which is one part of the NRC's responsibilities under the National Environmental Policy Act (NEPA). The results of that review are described in Supplement 2 of NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Oconee Nuclear Station."

In a letter dated July 6, 1998, Duke Energy Corporation (Duke) filed an application to renew the licenses for its three-unit Oconee Nuclear Station. Duke requested a 20-year extension in the license term for the three units. The existing licenses expire on midnight, February 6, 2013 (for Unit 1), midnight, October 6, 2013 for (Unit 2), and midnight, July 19, 2014, for (Unit 3). If granted, the renewed licenses would extend to February 6, 2033; October 6, 2033; and July 19, 2034, respectively.

The ONS is located in Oconee County in northwestern South Carolina on the shores of Lake Keowee. The three-unit nuclear station was constructed during the period from 1967 to 1974. Each unit consists of a Babcock and Wilcox (B&W) pressurized-water reactor nuclear steam supply system designed to generate 2568 MW thermal, or approximately 860 MW electric.

In accordance with 10 CFR Part 54, Duke submitted information in its renewal application that identifies all plant systems, structures, and components (SSCs): (1) that are safety-related, (2) whose failure could affect safety-related functions, and (3) that are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification, pressurized thermal shock, anticipated transients without scram, and station blackout. Duke's application also describes how the effects of aging will be managed in such a way that the intended functions of those structures and components will be maintained for the 20-year period of extended operation. These structures and components include, but are not limited to, the

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

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

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

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

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

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

The bases for the conclusions in this report are also reviewed by the NRC's Advisory Committee on Reactor Safeguards (ACRS). ACRS independently reviews the application and submits its recommendation directly to the Commission; that recommendation is included in the published version of this report (Chapter 5).

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

1 INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the application for license renewal for the Oconee Nuclear Station (ONS), Unit Nos. 1, 2, and 3, as filed by the applicant, Duke Energy Corporation (Duke or applicant). By a letter dated July 6, 1998, Duke submitted its application to the United States Nuclear Regulatory Commission (NRC) for renewal of the ONS operating licenses for an additional 20 years. The NRC staff prepared this report and reviewed 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 ONS is Joseph M. Sebrosky. Mr. Sebrosky may be contacted by calling him at 301-415-1132, or by writing to him at the License Renewal and Standardization Branch, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001.

In its July 6, 1998, submittal, Duke requested renewal of the operating licenses issued under Section 104 of the Atomic Energy Act of 1954, as amended, for ONS, Unit Nos. 1, 2, and 3 (license numbers DPR-38, DPR-47, and DPR-55, respectively) for a period of 20 years beyond the current license expirations of February 6, 2013; October 6, 2013; and July 19, 2014, respectively. The ONS is located in Oconee County in northwestern South Carolina on the shores of Lake Keowee. Each unit consists of a Babcock and Wilcox (B&W) pressurized-water reactor nuclear steam supply system designed to generate 2568 MW thermal, or approximately 860 MW electric. Details concerning the plant and the site are found in the updated Final Safety Analysis Report (UFSAR) for ONS, Unit Nos. 1, 2, and 3.

The license renewal process proceeds along two tracks: a technical review of safety issues and an environmental review. The requirements for these two reviews are stated in NRC regulations 10 CFR Parts 54 and 51, respectively. The safety review for the ONS license renewal is based on Duke's application for license renewal and on the applicant's answers to requests for additional information (RAIs) from the NRC staff. In meetings and docketed correspondence, Duke has also supplemented its answers to the RAIs and submitted answers to the open items identified in the June 16, 1999, version of this SER. The public can review the license renewal application (LRA) and all pertinent information and materials, including the UFSAR mentioned above, at the NRC Public Document Room, 2120 L Street, NW., Washington, D.C. In addition, the application and significant information and material related to the renewal review are available on the NRC Web page at www.nrc.gov.

This SER summarizes the findings of the staff's safety review of the ONS 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 staff reviewed the LRA in accordance with the NRC regulations and the guidance presented in the

NRC draft "Standard Review Plan (SRP) for the Review of License Renewal Applications for Nuclear Power Plants," dated September 1997.

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

Appendix A is a chronology of NRC's and Duke's principal correspondence related to the review of the application. Appendix B is a bibliography of the documents used during the course of the review. Appendix C 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. Appendix E presents an index of the staff's RAIs and Duke's responses.

In accordance with 10 CFR Part 51, the staff prepared draft and final plant-specific supplements to the generic environmental impact statement (GEIS) that discuss the environmental considerations related to renewing the license for the ONS, Unit Nos. 1, 2, and 3. The draft and final plant-specific supplements to the GEIS were issued separately from this report. Specifically, NUREG-1437 Supplement 2, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants Regarding the Oconee Nuclear Station" dated December 1999, is the final environmental report for ONS.

1.2 License Renewal Background

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

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

In 1986, the NRC published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to life extension for nuclear power plants.

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

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 on two key principles:

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

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

In implementing these two principles, the rule in 10 CFR 54.4, defines the scope of license renewal as those plant 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 structures and components subject to an aging management review (AMR). Structures and components subject to an AMR are those that perform an intended function without a change in configuration or properties and 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 structures and components 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. 10 CFR 54.21(d) requires that a supplement to the FSAR contain a summary description of the programs and activities for managing the effects of aging.

Another requirement for license renewal is the identification and updating of time-limited aging analyses. During the design phase for a plant, certain assumptions are made about the length of time the plant will be operated and these assumptions are incorporated into design calculations for several of the plant's SSCs. In accordance with 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 Licenses." This guide proposes to endorse an implementation guideline prepared by the Nuclear Energy Institute (NEI) as an acceptable method of implementing the license renewal rule. The NEI guideline is NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule," which was issued in March 1996. The NRC prepared a draft standard review plan (SRP) for the safety review, which was placed in the Public Document Room in September 1997. The draft regulatory guide will be used, along with the draft SRP, 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 SRP and clarify regulatory guidance.

1.2.2 Environmental Reviews

The staff revised the environmental protection regulations in 10 CFR Part 51 in December 1996 to facilitate the environmental review for license renewal. The staff prepared a "Generic Environmental Impact Statement (GEIS) for License Renewal of Nuclear Plants," NUREG-1437[1], in which it 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).

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[1] The GEIS was originally issued in 1996. Addendum 1 to the GEIS was issued in 1999. Hereinafter, all references to the "GEIS" include the GEIS and its Addendum 1.

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 October 19, 1998, near the ONS as part of the NRC's 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 were documented in NRC's draft plant-specific Supplement 2 to the GEIS, which NRC issued on May 20, 1999. During the 75-day comment period that followed, another public meeting was held near the site on July 8, 1999, at which the staff described the results of the NRC environmental review and answered questions related to it in order to provide members of the public with information to assist them in formulating any comments they might have regarding the review. On December 9, 1999, the staff issued the final version of Supplement 2 to the GEIS on the ONS, in which it presented its final environmental analysis that considers and weighs the environmental effects of the license renewal, and alternatives available for avoiding adverse environmental effects. The staff considered and addressed the comments that were received during the comment period.

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

1.3 Summary of Principal Review Matters

The requirements for renewing operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff performed its technical review of the ONS application for license renewal 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 technical review.

In 10 CFR 54.19(a), the Commission requires a license renewal applicant to submit general information. Duke submitted this general information in Enclosure 1 to its July 6, 1998, submittal letter regarding the application for renewed operating licenses for the ONS, Unit Nos. 1, 2, and 3. In that enclosure the staff finds that Duke submitted the information required by 10 CFR 54.19(a).

In 10 CFR 54.19(b), the Commission requires that LRAs 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." Duke stated the following in its renewal application regarding this issue:

> The current indemnity agreement for Oconee states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement. Item 3 of the Attachment to the

> indemnity agreement, as revised by Amendment No. 9, lists six license numbers. Duke requested that conforming changes be made to Article VII of the indemnity agreement, and/or Item 3 of the Attachment to that agreement, specifying the extension of agreement until the expiration dates of the renewed Oconee operating licenses as set forth in this Application. Thus, license number DPR-38 would be extended to expire at midnight, February 6, 2033; DPR-47 would be extended to expire at midnight, October 6, 2033; and DPR-55 would be extended to expire at midnight, July 19, 2034. In addition, should the license numbers be changed upon issuance of the renewed licenses, Duke requests that conforming changes be made to Item 3 of the Attachment, and any other section of the indemnity agreement as appropriate.

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 integrated plant assessment (IPA), (b) current licensing basis (CLB) changes during NRC review of the application, (c) an evaluation of time-limited aging analyses (TLAAs), and (d) a final safety analysis report (FSAR) supplement. Duke submitted the information to address the license renewal requirements of 10 CFR 54.21(a) and (c) in Exhibit A to the LRA of July 6, 1998. Exhibit A is titled "Oconee Nuclear Station, License Renewal—Technical Information, OLRP-1001." Duke submitted the information to address the license renewal requirements of 10 CFR 54.21(b) in a letter dated September 30, 1999. Duke submitted the information to address the license renewal requirements of 10 CFR 54.21(d) in Exhibit B of its LRA.

In 10 CFR 54.22, the Commission states requirements regarding technical specifications. Duke addressed the requirements of 10 CFR 54.22 in Exhibit C of its 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 presented the draft SRP titled "Review of License Renewal Applications for Nuclear Power Plants," which was published in September 1997. The staff's evaluation of the LRA in accordance with 10 CFR 54.21 and 54.22 appears in Chapters 2, 3, and 4 of this SER.

The staff's evaluation of the environmental information required by 10 CFR 54.23 can be found in the draft and final plant-specific supplements to the GEIS (NUREG-1437, Supplement 2), that state the considerations related to renewing the license for ONS, Unit Nos. 1, 2, and 3.

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

1.3.1 Babcock and Wilcox Topical Reports

In accordance with 10 CFR 54.17(e), Duke also incorporated by reference several Babcock and Wilcox Owners Group topical reports into the ONS LRA. The topical reports demonstrate generically that the aging effects for reactor coolant system components are adequately managed for the period of extended operation under a renewed license. Specifically, Duke incorporated the following topical reports into its application:

- BAW-2241P, "Fluence and Uncertainty Methodologies," May 1997
- BAW-2243A, "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," March 1996
- BAW-2244A, "Demonstration of the Management of Aging Effects for the Pressurizer," August 1997
- BAW-2248, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," July 1997
- BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," June 1996

The staff has issued separate safety evaluations for these topical reports. Specifically, the staff issued the final safety evaluations for the following topical reports: BAW-2243 on March 21, 1996; BAW-2244 on August 18, 1997; BAW-2241P on February 18, 1999; BAW-2251 on April 26, 1999; and BAW-2248 on December 9, 1999. In accordance with procedures established in NUREG-0390, "Topical Report Review Status," the staff requested that the Babcock and Wilcox Owners Group publish accepted versions of the reports. The accepted version incorporates the transmittal letter and the staff's safety evaluation between the title page and the abstract. The accepted versions includes an -A (designating accepted) following the report identification symbol.

Each safety evaluation for the topical reports is intended to be a standalone document. An applicant incorporating the topical reports by reference into its LRA must ensure that the conditions of approval contained in the safety evaluations are met. The staff's evaluation of how the topical reports were incorporated into the application is found in Section 3.4 of this SER.

1.4 Summary of Open Items and Confirmatory Items

As a result of its initial review of the LRA for the ONS, including the additional information submitted to the NRC, the staff identified a number of open issues and confirmatory items when this report was issued in June 1999. That report was revised to describe in each applicable section the manner by which those matters have been resolved.

2 STRUCTURES AND COMPONENTS SUBJECT TO AN AGING MANAGEMENT REVIEW

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

2.1.1 Introduction

10 CFR 54.21, "Contents of application — technical information," requires, in part, that each application for license renewal contains an integrated plant assessment (IPA) that identifies and lists those systems, structures, and components (SSCs) satisfying the criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) that are subject to an aging management review (AMR). 10 CFR 54.4, "Scope," defines the criteria for inclusion of SSCs within the scope of 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

The Oconee Nuclear Station (ONS) IPA was developed along traditional engineering disciplines, that is, mechanical, civil/structural, and electrical. The methodology used by the applicant to identify structures and mechanical systems at the ONS subject to an AMR is generally consistent with the industry guidance in an Nuclear Energy Institute (NEI) document NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 — The License Renewal Rule." However, the applicant developed a process specific to the ONS for identifying electrical components.

2.1.2 Summary of Technical Information in the Application

Exhibit A, "License Renewal — Technical Information (OLRP-1001)," to the ONS license renewal application (LRA) contains the technical information required by 10 CFR 54.21(a) and (c), including the methodology used to identify the SSCs at the ONS that are within the scope of license renewal. Exhibit A, Section 2.2, "Identification of Systems, Structures, and Components Within the Scope of License Renewal," describes the process used by the applicant to satisfy the criteria contained in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) for structures and mechanical systems at the ONS. The methodology used to identify electrical components within the scope of license renewal is described in Section 2.6, "Electrical Components," of Exhibit A.

Additionally, Section 2.3.1, "Description of the Process to Identify Reactor Building (Containment) Structural Components"; Section 2.4.1, "Description of the Process to Identify Reactor Coolant System Components and Class 1 Component Supports Subject to Aging Management Review"; Section 2.5.1, "Process Used to Identify Mechanical Components Subject to Aging Management Review"; Section 2.5.2, "Detailed Process Descriptions"; Section 2.6.1, "Description of the Process to Identify Electrical Components Subject to Aging Management Review"; and Section 2.7.1, "Description of the Process to Identify Structural

Components Subject to Aging Management Review," contain amplifying information on the process used by the applicant to satisfy the requirements of 10 CFR 54.21(a)(1) and (a)(2) for the ONS structural, mechanical, and electrical components that are subject to an AMR for license renewal.

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

In OLRP-1001, Subsection 2.2, "Identification of Systems, Structures, and Components Within the Scope of License Renewal" of Exhibit A of the LRA the applicant states the following:

> Because the ONS was licensed before terms such as 'safety-related' were more precisely defined by the NRC, a list of the ONS safety-related SSCs, in and of itself, will not meet the intent of 10 CFR 54.4(a)(1). Because the criteria in 10 CFR 54.4(a)(1) are the scoping criteria of many modern-day, regulatory-required programs, ONS conducted a design study that validated all functions required for the successful mitigation of ONS design-basis events and identified the systems and components relied upon to complete those functions. The individual design-basis event mitigation calculations produced as a result of the study contain a list of the system functions required to successfully mitigate each event. The applicant determined that the systems that perform these functions are within the scope of license renewal.

During an audit of the ONS license renewal scoping and screening process conducted by the NRC staff on October 27 through 30, 1998, at Duke Energy Corporation's offices in Charlotte, N.C., the audit team learned that the "design study" identified in Subsection 2.2.1.1 and the Oconee Safety-Related Designation Clarification (OSRDC) project developed in response to GL 83-28, "Required Actions Based on Generic Implications of Salem ATWS Events" (July 1983) was one and the same. Specifically, in its November 4, 1983, response to GL 83-28, as supplemented by letters dated January 17, 1984, and June 9, 1987, the applicant described the scope of the ONS operational QA program for safety-related equipment classification. The NRC staff approved the scope of the ONS operational QA program in a safety evaluation dated November 4, 1987.

In a supplemental response to GL 83-28, dated April 12, 1995, the applicant submitted amplifying information on the ONS QA-1 licensing basis, and on information given to the NRC Region II staff during a February 6, 1995, meeting. The QA-1 designation originally applied to ONS SSCs that were relied upon to mitigate a large-break loss-of-coolant accident (LBLOCA) coincident with a loss of offsite power (LOOP) event; the QA-1 designation did not encompass all SSCs which are relied upon to remain functional during and following design-basis events (DBEs) as defined under 10 CFR 54.4(a)(1).

In Attachment 3 to the April 12, 1995, letter, "Supplemental Response to Subpart 1 of Section 2.2.1 of GL 83-28 General Criteria for Classifying QA-1 SSCs," the applicant stated that the list of additional QA-1 SSCs would be developed through the OSRDC project by July 10, 1995. Also, in Attachment 4, "Oconee Licensing Position on Non QA-1 SSCs Which Are Used to Mitigate Accidents," the applicant committed to developing a new QA classification (QA-5) so that these SSCs can be identified for testing and maintenance under selected Appendix B [to 10 CFR Part 50] criteria without procuring the SSCs per Appendix B.

On this basis, and by letter dated December 1, 1998, the staff requested that the applicant do the following:

- Clarify the extent to which the ONS license renewal process described in Exhibit A of the LRA relied upon the OSRDC results.
- Describe the specific process (and its current status) used by the applicant to confirm that the OSRDC project has identified all ONS SSCs (including electrical) that perform the functions identified in 10 CFR 54.4(a).
- Identify and describe the administrative controls (and associated commitments) currently in place at ONS to ensure that QA-5 SSCs (identified through the OSRDC project), and subject to an AMR, will be adequately managed during the period of extended operation.

In its February 17, 1999, response to the staff's request for additional information (RAI 2.2-6), the applicant clarified the role of the OSRDC project in the ONS license renewal process. Subsequent to the applicant's response to the staff's RAI, the staff met with the applicant on March 11, 1999, to obtain clarification and additional insights into the methodology used by the applicant to meet the requirements of 10 CFR 54.4 for identifying the SSCs within the scope of the rule. As a result of the meeting on March 11, 1999, the applicant submitted additional information and clarifications in a letter dated March 18, 1999. In a May 11, 1999, meeting, which is documented in a meeting summary dated May 19, 1999, Duke met with the staff to further discuss the DBEs used by the applicant to determine the safety-related SSCs required by the scoping criteria under 10 CFR 54.4(a)(1). During this meeting Duke agreed to supplement its response to the staff's RAI 2.2-6, to include a description of the process used to identify events for Oconee license renewal scoping consistent with the presentation that was given to the staff.

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

During the audit of October 27 through 30, 1998, members of the NRC staff visited the Duke Energy Corporate Office in Charlotte, NC, to review the license renewal scoping and screening methodology and justification for the ONS LRA. The audit team reviewed the site-specific specifications used to identify the structures and components (SCs) subject to an AMR from those identified as being within the scope of the rule. The staff also reviewed other supporting documentation and interviewed applicant staff members as part of its evaluation of the applicant's process for identifying those SCs subject to an AMR. The staff also performed an inspection of the applicant's scoping process from April 26, 1999, to April 30, 1999, and performed another audit of the applicant's scoping methodology during the week of August 16, 1999. In addition, there were numerous public meetings, telecommunications, and docketed correspondence, including RAIs and RAI responses between the staff and the applicant to address specific scoping concerns as discussed below.

Mechanical Components Review

During the week of October 27, 1998, the site-visit team reviewed the methodology used by the applicant to identify and list the mechanical components subject to an AMR, as well as the applicant's technical justification for this methodology. The team also examined the applicant's results from the implementation of this methodology by reviewing an overview of the mechanical systems identified as being within the scope of license renewal, a sample of evaluation boundaries drawn within those systems, the resulting components determined to be within the scope of the rule, the corresponding component-level intended functions, and the resulting list of mechanical components subject to an AMR.

The site-visit team reviewed the methodology described in the LRA, Subsection 2.4 and 2.5, entitled "Reactor Coolant System Mechanical Components and Class 1 Component Supports," and "Mechanical System Components." The site-visit team also reviewed a number of on-site engineering documents not docketed, including Oconee site specification OSS-0274.00-00-0001, "Oconee Mechanical System Scoping for License Renewal"; OSS-274.00-00-0002, "Oconee Mechanical Component Screening for License Renewal"; appropriate portions of the ONS updated final safety analysis report (UFSAR); the ONS flow diagrams that contain the color-coded evaluation boundaries for the systems identified as being within the scope of license renewal; and the mechanical component commodity-type menus developed by the applicant to identify the SCs that are required to be subject to an AMR under 10 CFR 54.21(a)(1)(i) and (a)(1)(ii). The site-visit team found the applicant's process consistent with the scoping process described in the "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule" (NEI 95-10, Revision 0), and adequate for the purpose of determining the mechanical components requiring an AMR. However, the staff needed to better understand the OSRDC process, which was used to determine the applicable design-basis events defined in the applicant's current licensing basis (CLB), to ensure that all the mechanical systems, as required by 10 CFR 54.4(a)(1) and (a)(2), were identified as being within the scope of license renewal.

As a result of the information reviewed, the staff issued RAI 2.2-6 relating to the design-basis events used to determine the mechanical systems within the scope of the rule and the resulting components requiring an AMR. Duke provided an initial response to the staff's request for additional information in a letter dated February 17, 1999. The RAI response was followed by a technical meeting on March 11, 1999, and a supplemental response from Duke dated March 18, 1999.

During the week of April 26, 1999, the staff performed an inspection of the results of the applicant's scoping activities including the scoping of mechanical SSCs. The results of this inspection were documented in NRC inspection report number IR99-011. On May 11, 1999, the applicant met with NRC staff to further discuss concerns with its list of design-basis events that were used to scope mechanical SSCs for the purpose of license renewal. That meeting led to additional information provided by the applicant in a letter dated June 22, 1999. The staff performed a third site visit during the week of August 16, 1999, to audit additional design documentation relative to the scoping methodology and the design-basis events used in the applicant's scoping process. As a result of a number of additional meetings and docketed correspondence between the staff and the applicant, Duke submitted its final response on November 30, 1999. The response discussed specific events and their inclusion as scoping events for the purpose of license renewal.

Structures and Structural Component Review

The site-visit team reviewed the methodology used by Duke to identify and list the structural components subject to an AMR, as well as the applicant's technical justification for this methodology. The team also examined the applicant's results from the implementation of this methodology by reviewing the structural components identified as being within the scope of license renewal, the corresponding structural-level intended functions, and the resulting list of structural components subject to an AMR.

The site-visit team reviewed the methodology described in the LRA, Subsection 2.3 and 2.7, entitled "Reactor Building Structural (Containment) Components," and "Structures and Structural Components." The site-visit team also reviewed a number of on-site engineering documents including Oconee site specification OSS-0274.00-00-0007, "Oconee Structures and Structural Component Aging Management Review," a number of other ONS specifications relating to structural classifications, appropriate portions of the ONS UFSAR, ONS General Arrangement Drawings, ONS Commodities and Facilities Drawings, and Quality Standards Manual NSD 307. As a result of the information reviewed, the staff issued RAI 2.6.7-1 requesting additional information relating to the validations of the structures determined not to be within the scope of license renewal. Duke provided a response to the staff's request for additional information in a letter dated February 17, 1999. The RAI response was followed by a technical meeting on March 11, 1999. During the week of April 26, 1999, the staff also performed an inspection of the results of the applicant's overall scoping activities including the scoping of structural SSCs.

Electrical Components Review

The site-visit team reviewed the methodology used by Duke to identify and list the electrical components subject to an AMR, as well as the applicant's technical justification for the identification process. The team examined the applicant's results from the implementation of this methodology by reviewing the list of electrical components subject to an AMR.

The site-visit team reviewed the methodology described in the LRA, Subsection 2.6, entitled "Electrical Components." The site-visit team also reviewed a number of on-site engineering documents including Oconee site specification OSS-0274.00-00-0006, "Oconee Electrical Component Aging Management Review for License Renewal," appropriate portions of the ONS UFSAR, ONS Electrical Drawings, and NEI 95-10, Revision 0. The site-visit team found the applicant's process to be significantly different from the scoping process described in the industry guideline, NEI 95-10, and determined that additional information was needed for the staff to adequately assess the applicant's process for scoping electrical SSCs.

As a result of the information reviewed, the staff issued RAI 2.6-1 requesting additional clarification of the applicant's scoping process. Duke provided an initial response to the staff's request for additional information in a letter dated February 17, 1999. The RAI response was followed by a technical meeting on March 11, 1999, and a supplemental response from Duke dated March 18, 1999. As previously noted, during the week of April 26, 1999, the staff also performed an inspection of the results of the applicant's overall scoping activities including the scoping of electrical SSCs.

2.1.3 Staff Evaluation

In Section 2.2, "Identification of Systems, Structures, and Components Within the Scope of License Renewal," of Exhibit A of the LRA, the applicant described the methodology used to identify the mechanical components that are within the scope of license renewal and subject to an AMR. The mechanical components included within the scope of license renewal and subject to an aging management review are described in Section 2.4, "Reactor Coolant System Mechanical Components and Class 1 Component Supports," and Section 2.5, "Mechanical System Components" of Exhibit A of the LRA. The structures included within the scope of license renewal and subject to an aging management review are described in Section 2.3, "Reactor Building (Containment) Structural Components," and Section 2.7, "Structures and Structural Components," of Exhibit A of the LRA. The electrical components included within the scope of license renewal and subject to an aging management review are described in Section 2.6, "Electrical Components," of Exhibit A of the LRA.

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

As indicated above, the applicant stated in its LRA that ONS conducted a design study that was used to validate all the functions required for the successful mitigation of ONS design-basis events and identified the SCs relied upon to complete those functions. On October 27 through 30, 1998, members of the NRC staff visited the Duke Energy Corporate Office in Charlotte, NC, to review the license renewal scoping and screening methodology and justification presented in the ONS LRA. As a result of that review, the staff confirmed that the applicant relied on a design study to identify the SSCs that are needed to satisfy the requirements of 10 CFR 54.4(a).

The site-visit team discussed this design study and the process used to identify the SSCs within the scope of the rule. The basic process, as described by the applicant, involved identifying all the SSCs that met the "safety-related criteria" under 10 CFR 54.4(a)(1). Evaluation boundaries were established for the portions of those systems and structures required to perform the system functions that satisfied the specified criteria. In addition, the applicant stated that it had reviewed the non safety-related SSCs whose failure could prevent the successful completion of the safety functions identified from the review of the safety-related criteria under 10 CFR 54.4(a)(2). Again, evaluation boundaries were established for the portions of those non safety-related systems and structures. The components within those evaluation boundaries that were not already identified were added to the scope of license renewal.

The team found the results of the applicant's design study and subsequent scoping activities to be a reasonable approach for identifying a supplemental list of SSCs to complement the applicant's list of QA-1 SSCs required by the scoping criteria under 10 CFR 54.4 (a)(1) and (a)(2). However, the team concluded that the design study used by the applicant to meet the scoping requirements for license renewal was not fully described in the LRA. Therefore, the staff submitted a request for additional information to obtain the necessary information.

In its February 17, 1999, response to the staff's request for additional information (RAI 2.2-6), the applicant clarified the role of the OSRDC study in the Oconee license renewal scoping process. Specifically, the applicant stated that the "design study" in Exhibit A of the LRA refers only to the second initiative of the OSRDC project. The purpose of the first initiative of the project, identified as a commitment associated with the applicant's response to GL 83-28, was to clarify the ONS QA-1 licensing basis by developing a list of all QA-1 SSCs at ONS.

The purpose of the second initiative of the OSRDC study was to clarify ONS's licensing basis with respect to design-basis-event mitigation requirements, that is, to identify non-QA-1 SSCs credited with accident mitigation functions at ONS and those SSCs whose failure could prevent satisfactory accomplishment of any of the applicable accident mitigation functions. The third and fourth initiatives of the OSRDC project involved identifying and implementing an "augmented" QA (QA-5) program for those SSCs identified as a result of the second initiative and were not relevant to the license renewal scoping process.

Subsequent to the applicant's response to the staff's RAI, the staff met with the applicant on March 11, 1999, to obtain clarification and additional insights into the methodology used by the applicant to justify the scoping results. Specifically, the staff requested that the applicant describe its methodology for identifying the SSCs within the scope of 10 CFR 54.4(a)(1) and (a)(2) as it applies to design-basis events defined under 10 CFR 50.49(b)(1).

During the March 11, 1999, meeting, the discussion focused on which ONS design-basis events (DBEs) were considered in the ONS license renewal scoping process. Specifically, the staff was interested in how the applicant complied with the requirements of 10 CFR 54.4(a)(1) and with the definition of DBEs in 50.49(b)(1). The applicant stated its position that the set of DBEs contained in Chapter 15 of the ONS Updated Final Safety Analysis Report (UFSAR) complies with the requirements of 10 CFR 54.4(a)(1) and meets the definition in 10 CFR 50.49(b)(1). The applicant also stated that in order to be conservative, it considered an additional set of events based on plant-specific insights.

In a letter dated March 18, 1999, the applicant submitted additional information and clarifications as a result of the meeting on March 11, 1999. Specifically, the applicant: (1) amended its original response to RAI 2.2-6 to provide additional clarification in accordance with discussions held during the meeting, (2) amended its response to RAI 2.6-1 to clarify the electrical scoping description and to indicate how the results were validated, and (3) amended its response to RAI 2.6.7-1 to indicate how the validation of structural results was performed.

In a May 11, 1999, meeting, which is documented in a summary dated May 19, 1999, Duke stated that the license renewal "scoping events" included UFSAR Chapter 15 events, natural phenomena criteria, post-Three Mile Island emergency feedwater design basis scenarios, and turbine building floods mitigated by the standby shutdown facility. Duke considered a total of 26 events when initially scoping to comply with 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(2). Duke also stated that it reviewed an additional 32 events for possible inclusion into the set of scoping events. Duke determined that none of the additional 32 events needed to be considered for purposes of scoping in accordance with 10 CFR 54.4 (a)(1) and 10 CFR 54.4(a)(2). Because of the narrow definition of DBEs used by the applicant, the staff was concerned that the applicant may have overlooked some SCs needed to prevent or mitigate any of the additional 32 events that might have been identified if the applicant used the broader 10 CFR 50.49(b)(1) view of a DBE. Therefore, the applicant was then asked to take the following actions:

- Supplement its response to the staff's request for additional information (RAI 2.2-6) to include a description of the process used to identify events for ONS license renewal scoping consistent with the presentation that was given to the staff on May 11, 1999. The applicant also agreed to provide an explanation as to how the 26 events identified during the May 11, 1999 meeting were sufficient to satisfy 10 CFR 54.4(a)(1) and (a)(2). This was Open Item 2.1.3.1-1.

- Once the information identified above was provided, the staff determined that additional inspection activities were needed. This was also part of Open Item 2.1.3.1-1.

The staff reviewed the applicant's response to Open Item 2.1.3.1-1 provided in a letter dated June 22, 1999, and performed an audit of on-site information during August 16-18, 1999. The staff then performed a review of the 32 events, that were originally considered by the applicant but determined not to be DBEs, against the applicant's UFSAR, license conditions, the applicable regulations, Commission orders, and exemptions that are in effect and that define the applicant's design requirements. As a results of these activities, the staff identified 10 events that the staff believed needed additional consideration under the license renewal scoping criteria, 10 CFR 54.4(a) of the rule. The applicant was asked to reevaluate these 10 events for potential SCs that needed to be included within the scope of license renewal. In response to this request the applicant identified seven additional events that needed to be considered for scoping under 10 CFR 54.4(a)(1) and (a)(2). The results of the applicant's review were as follows:

- Five events (high energy line break, loss of control room, steam generator overfill, steam generator dryout, and loss of instrument air) had components that met the scoping criteria. However, the components from these five events, that met the scoping criteria under 10 CFR 54.4(a), were already included in the scope of license renewal for other applications with similar intended functions.

- One event (loss of spent fuel pool cooling) credited "operator actions and mentioned non-specific plant capability." This event met the definition for a DBE, but did not require adding any additional systems and components to the current scope of mechanical systems and components.

- One event (loss of decay heat removal) credited the non safety-related reactor coolant bleed transfer pumps and connecting piping in addition to two other safety-related systems and components. The applicant included the two safety-related systems and components for other applications. However, because redundant means of adding inventory to the reactor coolant system in case of such an event were available, the non safety-related mechanical systems and components were not added to the scope of license renewal.

- Three events (control of heavy loads, loss of condensate, and internal flooding of Auxiliary Building) were not identified in any of the five document types that define the applicant's design requirements, and thus, were not included as scoping events.

As a result of this review, the applicant did not identify any additional SSCs associated with these ten events, that needed to be added to the scope of license renewal, and therefore, did not add any addition SCs to the list of SCs subject to an AMR.

On the basis of the staff's reviews and the applicant's actions described above, the staff found that there is reasonable assurance that the applicant has considered the necessary DBEs in the implementation of its scoping methodology used to identify the SSCs required by the scoping criteria under 10 CFR 54.4(a)(1) and (a)(2). Open Item 2.1.3.1-1 is closed.

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

Mechanical Components

The methodology used by the applicant for identifying mechanical component within the scope of the rule included the following steps: identifying all systems and their intended functions that are relied upon to remain functional during and following the design-basis events for which the plant must be designed; identifying all the systems and intended functions whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(1); identifying all those systems and intended functions necessary to demonstrate compliance with the regulated events identified under 10 CFR 54.4(a)(3); and identifying all other mechanical systems or portions of systems that contain safety-related and seismically designed components.

The process used by the applicant to identify the mechanical components requiring an AMR included a set of highlighted ONS flow diagrams that were used to define the evaluation boundaries of the license renewal-related equipment. These highlighted drawings identified the flow paths required to be functional during and following design-basis events, and the components necessary for each system to accomplish its intended function(s). Interfacing flow paths, which share a common pressure boundary with the principal path, or non safety-related flow paths whose failure could prevent satisfactory accomplishment of any of the safety-related functions under 10 CFR 54.4(a) were included. The highlighted flow diagrams were color-coded to distinguish between Class 1 and non-Class 1 seismic piping.

In Exhibit A, Section 2.5.2, “Detailed Process Description,” the applicant described the process to scope and screen mechanical components within the scope of the rule and subject to an AMR. However, details regarding this methodology that would give the staff an understanding about how the requirements of 10 CFR 54.21 are being met were not provided. In RAI 2.5.2-1, the staff asked the applicant to provide a brief narrative that explained how the screening of mechanical components within the scope of license renewal was performed. In its response to this RAI, Duke stated the following:

> The mechanical component screening is consistent with the guidance provided in NEI 95-10, Rev. 0. Components subject to an AMR are those that are “passive” and “long-lived.” A menu of every mechanical component type installed at ONS was developed, going beyond the list of components in NEI 95-10. Using the “passive” and “long-lived” guidance, a determination was made for each of those mechanical component types. The components within the evaluation boundaries shown on the license renewal flow diagrams were “driven” through the menu to determine if they were subject to an AMR. From this exercise, a list of components subject to an AMR was developed.

The staff notes that the mechanical components subject to an AMR resulting from the applicant's process described in Section 2.5.2 of the LRA, and the mechanical screening process discussed in the response to RAI 2.5.2-1, are provided in Sections 2.5.3 through 2.5.14 of the LRA.

After the evaluation boundaries were established, the process is designed to identify those components within the evaluation boundaries that require an AMR primarily by eliminating those components excluded under 10 CFR 54.21(a)(1)(i). The applicant also identified the component-level intended functions that are required to fulfill the system-level intended functions during the scoping process. The resulting list of components, and groups of component types subject to an AMR was presented in the LRA, Subsections 2.5.3 through 2.5.14 and associated tables. These tables also contained the intended functions and the materials of construction for each of the mechanical components.

On the basis of the above review, the staff finds that the methodology used by the applicant to identify mechanical components that require an AMR is consistent with the requirements of the rule. The evaluation for the specific implementation of this methodology for ONS mechanical components can be found in Section 2.2 of this safety evaluation.

Structures

The screening process for structures began with the development of a list of structural component types from the structures determined to be within the scope of the rule using the requirements of 10 CFR 54.21, and the guidance contained in NEI 95-10, and the "NUMARC Containment and Class I Structures Industry Report." Other structural components were added from the review of the commitments made by the applicant with respect to the "regulated events" identified under 10 CFR 54.4(a)(3). The applicant also reviewed design basis specifications and structural drawings to complete its list of structural components within the scope of the rule. To verify that the list was complete, an independent review was performed by ONS structural experts.

The applicant then identified structural component-level intended functions from information in the UFSAR, ONS site specifications, commitments associated with design-basis events, regulated events, or input from Duke structural experts. This resulted in a list of component-level functions that supported the structural-level intended function plus some additional intended functions unique to individual components. For example, the spent fuel storage racks have a component specific intended function to provide separation to prevent criticality which does not match the Auxiliary building intended functions. The applicant then removed those structural components identified as performing their intended function with moving parts or a change in configuration or properties in the rule and in NEI 95-10, Appendix B. The applicant also removed all structural components that are replaced based on qualified life or specified time period. The remaining components were listed as structural components requiring an AMR.

On the basis of the above review, the staff finds that the methodology used by the applicant to identify the structures and structural components that require an AMR is consistent with the requirements of the rule. The implementation of this methodology and the listing of the structures and structural components for Reactor Building and other structures is evaluated in Section 2.2 of this safety evaluation.

Electrical Component

The methodology used to identify the electrical component requiring an AMR was different from the methodology used for mechanical and structural components. The applicant opted to develop a different process from the industry guidance. During the staff initial review, and the October 27 through 30, 1998 site-visit, the staff found the applicant's methodology unclear. The staff expressed its concern and documented its need for additional information in a letter dated December 1, 1998. In its February 17, 1999, response to the staff's request for additional information (RAI 2.2-6), the applicant provided a written description of its methodology.

The process for determining the electrical components subject to an AMR began with a complete list of all electrical component-types used at ONS. For this list of component types, the applicant identified the intended function(s) and eliminated those component types that required moving parts, or a change in configuration or properties to perform its intended function(s) as allowed by 10 CFR 54.21(a)(1)(i) and staff agreed-upon guidance in NEI 95-10. For those components remaining, the applicant eliminated a selected group of component types that did not meet the scoping criteria under 10 CFR 54.4(a). Finally, the applicant eliminated those components that are replaced based on a qualified life or specified time period. All remaining components are subject to an AMR. The above process describes the basic steps used in the identification of electrical components. Although this process is not consistent with the industry guidance provided in NEI 95-10, it is permitted by the rule and the staff finds it acceptable.

On the basis of the above review, the staff finds that the methodology used by the applicant to identify electrical components that require an AMR is consistent with the requirements of the rule. The evaluation for the specific implementation of this methodology for ONS electrical components can be found in Section 2.2.3.7 of this safety evaluation.

2.1.4 Conclusions

On the basis of the above review, the staff finds that there is reasonable assurance that the applicant's methodology for identifying the SSCs within the scope of license renewal and requiring an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

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

2.2.1 Introduction

In Sections 2.3 through 2.7 of Exhibit A, "License Renewal —Technical Information," of the LRA, the applicant described the SCs that are subject to an AMR for license renewal. The staff reviewed these sections of the LRA to determine if there is reasonable assurance that the applicant has listed those SCs subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

2.2.2 Staff Evaluation Approach

The staff reviewed Sections 2.3 through 2.7 of Exhibit A to the LRA to determine if there is reasonable assurance that the applicant has appropriately identified and listed those SCs subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1). The statement of considerations (SOC) for the license renewal rule (60 FR 22478) indicates that an applicant has the flexibility to determine the set of SCs for which an AMR is performed, provided that this set encompasses the SCs for which the Commission has determined an AMR is required. Accordingly, the staff focused its review on verifying that the implementation of the applicant's methodology discussed in Section 2.1 of this safety evaluation report (SER) did not result in the omission of SCs subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff performed the following two-step evaluation:

- The first step was to determine whether the applicant has properly identified the SSCs within the scope of license renewal, pursuant to 10 CFR 54.4. As described in detail below, the staff reviewed selected SCs that the applicant did not identify as within the scope of license renewal to verify that they do not meet the criteria in 10 CFR 54.4.

- The second step was to determine whether the applicant had properly identified the SCs subject to an AMR from among those identified in the first step. As described in detail below, the staff reviewed selected SCs that the applicant had identified as within the scope of license renewal but not subject to an AMR to verify that the applicant has identified the appropriate SCs subject to an AMR. The SCs are 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 did not review SCs that the applicant had already identified as subject to an AMR because it is an applicant's option to include more SCs than those required by 10 CFR 54.21(a)(1).

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

2.2.3 Systems, Structures, and Components

The applicant presented its methodology (i.e., the integrated plant assessment (IPA)) to identify the SSCs within the scope of license renewal in Sections 2.1 and 2.2 of Exhibit A of the LRA. This IPA methodology consists of a review of all plant systems and structures to determine those that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4. The staff reviewed the IPA methodology and presented its evaluation in Section 2.1 of this SER. The applicant documented the implementation of that methodology in Sections 2.3 through 2.7 of Exhibit A of the LRA.

To ensure that the IPA methodology described in Sections 2.1 and 2.2 of Exhibit A of the LRA was implemented properly and identified the systems and structures within the scope of license renewal, the staff performed the following additional review: the staff sampled the contents of the UFSAR to identify systems or structures that may have intended functions meeting the scoping requirements of 10 CFR 54.4 that the applicant did not include within the scope of license renewal; the staff selected several systems, such as the radiation monitors and spent fuel building ventilation; and in a letter to the applicant dated December 2, 1998, the staff requested additional information about these systems.

In their January 25, 1999, response to NRC RAI 2.2-7 on whether radiation monitors were within the scope of license renewal, the applicant stated that the radiation monitors do not support any system intended functions as defined in 10 CFR 54.4(a). The staff agrees that while some radiation monitors do not support system intended functions. However, the staff believed that radiation monitors that detect activity in the control room air supply are credited for initiating certain operator actions. This continuous radiation monitoring was thought to be a safety-related function that cautions the control room operators to manually activate the filtration train of the control room pressurization and filtration system for Units 1, 2, and 3 control rooms under given accident conditions to meet TMI Action Plan Item III.D.3.4, for control room habitability.

The continuous radiation monitoring is described in ONS UFSAR Section 9.4.1.3, which states that "[r]eturn air from the control room is continuously monitored by a radiation monitor before recirculating back to the control room. A high radiation level will alert the operators to energize the outside air filter trains." On April 8, 1999, the staff requested that the applicant clarify its justification for excluding the radiation monitors from within the scope of license renewal. On May 10, 1999, the applicant responded to the staff's April 8, 1999, request for clarification of RAI 2.2-7. In its response, the applicant stated that although radiation monitors RIA-39 for Units 1, 2, and 3 will prompt operators to energize outside filter trains, operation of the monitors is not relied upon for the successful mitigation of any design-basis event and failure of the monitors will not prevent the successful mitigation of any design-basis event. In addition, the applicant stated that the radiation monitors are not relied upon to meet the requirements of any of the regulated events identified in 10 CFR 54.4(a)(3). The staff also requested that the applicant review the functions of the radiation monitors on OLRP-1002 drawings OLRFD-116C-1.1, 124B-1.5, and 133A-1.5 to ensure that these monitors did not have any intended functions that would require the monitors be included within the scope of license renewal. In its May 10, 1999, response, the applicant stated that the radiation monitors identified on the referenced drawing are all non-safety-related and not relied upon for the successful mitigation of a design-basis event. The staff has reviewed the applicant's responses and agrees that the radiation monitors are not within the scope of license renewal.

In NRC RAI 2.2-8, the staff asked the applicant to justify the omission of the spent fuel pool (SFP) ventilation system from within the scope of license renewal. SFP area ventilation is often credited in mitigating fuel handling accidents as well as performing other safety functions. The applicant responded in a letter dated February 17, 1999, that its analyses show that the system is not required to remain functional during or following any design-basis event to ensure any of the functions required by 10 CFR 54.4(a)(1) and does not meet the criteria of 10 CFR 54.4(a)(2) or (3) and is, therefore, not within the scope of license renewal. The staff reviewed the applicant's response and Chapter 15 of the UFSAR, and agreed with the applicant's decision to not include the system in the scope of license renewal.

In a letter to the applicant dated April 16, 1999, the staff requested additional information (RAI 2.5-1) concerning the identification and listing of components associated with instrumentation lines within the scope of license renewal. Rules for highlighting the OLRFD drawings in the front of each OLRP-1002 volume of flow diagrams contain the statement, "[a]ll instrumentation lines normally open to the process flow through, but not including the instrument, are included in license renewal. These lines are not highlighted except for containment penetrations." Section 2.5 of Exhibit A of the LRA lists the mechanical systems within the scope of license renewal and presents a table for each system at the end of the section identifying the components that are subject to an AMR. The staff review of these tables generally found the component "tubing" on the table of components subject to an AMR. However, several systems did not list tubing as a component, even though some instrument lines originated from points of the system that were within the scope of license renewal. In the letter dated April 16, 1999, the staff requested that the applicant clarify the status of the instrumentation lines for the following systems:

- reactor building cooling
- reactor building spray
- component cooling
- condenser circulating water
- auxiliary building HVAC
- feedwater
- standby shutdown facility HVAC

On May 10, 1999, the applicant responded to the staff's RAI. The applicant stated that for three systems, reactor building spray, component cooling, and feedwater, stainless steel tubing is included within the scope of license renewal and was inadvertently omitted from Tables 2.5-2 and 3.5-2 of the LRA. For three systems, reactor building cooling system, auxiliary building ventilation system, and the SSF HVAC System, no tubing exists within the license renewal boundaries of the systems. For the Condenser Circulating Water (CCW) System, the applicant stated that this system does have instrumentation lines within the license renewal boundaries, but they do not perform any intended function and are, therefore, not subject to an AMR. Therefore, this tubing was not included on Table 2.5-9 for the CCW System. The staff reviewed the applicant's response and found it acceptable.

In Section 9.2.2.2.4 of the ONS UFSAR, the applicant described the design and operation of the Recirculation Cooling Water (RCW) System. One function of the RCW System is to remove decay heat from the stored fuel in the spent fuel pool by transferring the heat from the spent fuel pool coolers to the CCW System. In the UFSAR, the applicant also stated that the SFP Cooling System is designed to keep the pool bulk temperature below 150°F under a variety of postulated normal and upset conditions, and under 205°F when considering abnormally high heat loads and certain equipment failure. The UFSAR further stated that 205°F represents the actual operating limit, because calculations show that the seismic and structural integrity of the pool is not compromised below this temperature. In addition, Chapter 15 Section 11.2.1 of the UFSAR stated the assumptions for a fuel handling accident in the SFP, which include a fuel assembly gap pressure based on a bulk SFP coolant temperature of 150°F.

Since the RCW System is relied upon to supply cooling water to the SFP Cooling System coolers to maintain the bulk SFP coolant temperature below the SFP design limits and below assumptions for the fuel handling accident analysis described in Section 15.11.2.1 of the UFSAR, the staff requested that the applicant clarify the basis for excluding the RCW System from the scope of license renewal. This issue was identified as Open Item 2.2.3-1.

In letters dated October 15, and November 30, 1999, the applicant responded to Open Item 2.2.3-1. The applicant clarified the basis of the SFP Cooling System design and the reason for omitting the RCW System from the scope of license renewal. In its response, the applicant stated that the fuel handling accident analysis for ONS assumes that spent fuel pool cooling, and thus the RCW System, is not functional during or following such an event. The applicant stated that the results of the safety analysis for the fuel handling accident demonstrates that the consequences of such an accident are within the 10 CFR Part 100 guidelines. The normal operating temperature for the spent fuel storage pool established by the ONS operating procedures ensure that the results of a fuel handling accident analysis remain valid even if all forced cooling to the spent fuel pool is lost at the commencement of the accident. 10 CFR 54.4(a)(1) states that safety-related SSCs, which are those relied upon to remain functional during and following design-basis events to ensure the capability to mitigate or prevent the consequences of an event (such as a fuel handling accident), that could result in potential offsite exposure comparable to 10 CFR Part 100 guidelines shall be included within the scope. Since the applicant's analysis demonstrated that spent fuel pool cooling is not required to remain functional during or following a fuel handling accident or to prevent or mitigate the consequences that could result in potential offsite exposure comparable to 10 CFR Part 100 guidelines, the SSCs required to fulfill the function of decay heat removal from the spent fuel pool, including the RCW System, are not within the scope of license renewal. The staff reviewed the reasons for excluding the RCW System from the scope of license renewal and found the applicants justification acceptable. On the basis of this review and the staff's findings, Open Item 2.2.3-1 is closed.

The staff reviewed the information submitted by the applicant in the LRA, information in the ONS UFSAR, and additional information in the applicant's January 25, February 17, and May 10, 1999, responses to the NRC's December 2, 1998, and April 16, and October 15, 1999, letter, and did not identify any systems or structures with intended functions that were not already evaluated in the LRA. Therefore, the staff has reasonable assurance that the applicant has appropriately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.2.3.1 Containment Structures

2.2.3.1.1 Concrete Components, Steel Components, and Post-Tensioning System

In Section 2.3, "Reactor Building (Containment) Structural Components," of Exhibit A of the LRA, the applicant identified the SCs that are within the scope of license renewal and which of those within-scope SCs are subject to an AMR.

Component (equipment and piping) supports for the SCs described below are covered separately in Section 2.7 of Exhibit A of the ONS LRA. Electrical components that support the operation of the systems are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant included instrument line components with the system to which they are attached.

2.2.3.1.1.1 Summary of Technical Information in the Application

The reactor buildings are Class 1 structures which prevent uncontrolled release of radioactivity. The applicant has determined that Class 1 structures meet the intent of 10 CFR 54.4(a)(1) and are within the scope of license renewal. A part of the reactor building, the containment, includes the concrete containment structure, liner, and all penetrations. The containment has been divided into three groups according to material of construction and component-level function.

These component groups are described in Section 2.3.2, "Concrete Components"; Section 2.3.3, "Steel Components"; and Section 2.3.4, "Post-Tensioning System." The three containment component groups within the scope of 10 CFR Part 54 and their intended functions are given in Table 2.3-2 of Exhibit A of the LRA.

The concrete component group consists of the cylinder wall, dome, floor, and foundation slab. The applicant identified the following intended functions for the concrete component group:

- Provide structural and/or functional support to safety-related SSCs
- Provide shelter and protection for safety-related SSCs (including radiation protection)
- Serve as an external missile barrier
- Provide structural and/or functional support to non-safety-related SSCs where failure of this structural component could directly prevent satisfactory accomplishment of any of the required safety-related functions
- Provide a heat sink during design-basis accidents or station blackout

One additional intended function identified for the cylinder wall, was the need for the wall to provide a rated fire barrier to confine or retard a fire from spreading to or from adjacent areas of the plant.

The steel component group includes anchorages, embedments, attachments, electrical penetrations, emergency personnel hatch, equipment hatch, fuel transfer tubes, liner plate, mechanical penetrations, and personnel hatch. All the components of the steel component group have the intended function of providing an essentially leak-tight barrier to prevent uncontrolled release of radioactivity. For anchorages, embedments, and attachments, the applicant also identified the intended function of providing a structural and/or functional support to safety-related SSCs and non-safety-related SSCs where failure of the structural component could directly prevent satisfactory accomplishment of any of the required safety-related functions. Mechanical penetrations also provide structural and/or functional support to safety-related SSCs and this was identified as an intended function. Finally, the ability of the liner plate to provide a heat sink during design-basis accidents or station blackout was identified as an intended function.

The post-tensioning group comprises two component types, tendon anchorage and tendon wires. Providing structural and/or functional support to safety-related SSCs was identified as the intended function for the post-tensioning group. More specifically, this function involves imposing compressive forces on the concrete containment structure to resist the internal pressure resulting from a design-basis accident with no loss of structural integrity.

2.2.3.1.1.2 Staff Evaluation

The staff reviewed Section 2.3 of Exhibit A of the LRA to determine whether there is reasonable assurance that the applicant has identified the containment SCs subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.1.1.2.1 Containment Structures, Systems, and Components Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed Section 6.2.1, "Containment Functional Design," of the UFSAR and compared the description of the structures, systems, and other components in the UFSAR to the description in the application to determine if there were any additional portions of the system that the applicant should have identified as within the scope of license renewal. As described in Sections 2.3 and 2.7 of Exhibit A of the LRA, essentially all portions of the containment were determined to be within the scope of license renewal and subject to an AMR. The staff reviewed the few remaining components of the containment to verify that they do not perform any intended functions. The staff also reviewed Section 6.2.1 of the UFSAR to determine if there were any additional functions that were not identified as intended functions in the LRA. The staff found no omissions. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the containment structures which fall within the scope of license renewal and are subject to an AMR in accordance with 10 CFR Part 54.

In RAI 2.3-8, the staff asked the applicant why the tendon gallery, which provides access to the bottom anchorages of the vertical tendons as part of the post-tensioning system, had not been included within the scope of license renewal under 10 CFR 54.4(a)(2). In response to the RAI the applicant stated that the function of the tendon access gallery is to provide access to the bottom of the vertical tendons so that they can be tested and that its failure would not prevent satisfactory accomplishment of any of the functions identified by 10 CFR 54.4(a)(1)(i), (ii) or (iii). The staff agrees that the tendon gallery itself is not within the scope of license renewal. However, operational experience, as documented in NUREG-1522, has shown that water infiltration and high humidity in the tendon gallery can be a significant aging effect on the vertical tendons that could potentially result in loss of the ability of the post-tensioning system to perform its intended function. This is reflected in Open Item 3.3.3.1-1.

In RAI 2.3-11, the staff asked the applicant why the function(s) of the containment sump was not identified as an intended function(s) of the containment. The applicant responded to the RAI by stating that the sumps were not included in Section 2.3 of Exhibit A of the LRA because they do not perform the function of providing an essentially leak-tight barrier to prevent uncontrolled release of radioactivity, which is the function of the containment building. However, the emergency and normal sumps are included in Section 2.7 with reactor building internal structures as components requiring an AMR.

2.2.3.1.1.3 Review Findings for Concrete Components, Steel Components, and Post-Tensioning System

As described above, the staff has reviewed the information provided in Section 2.3 of Exhibit A of the LRA and the additional information provided by the applicant in response to the staff's RAIs. The staff has reasonable assurance that the applicant has appropriately identified those portions of the containment, and the associated SCs thereof, that are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4.

2.2.3.2 Reactor Coolant System

2.2.3.2.1 Reactor Coolant System

In Section 2.4, "Reactor Coolant System Mechanical Components and Class 1 Component Supports," of the LRA, the applicant described the SCs of the Reactor Coolant System (RCS) that are subject to an AMR for license renewal.

2.2.3.2.1.1 Summary of Technical Information in the Application

As described in the application, the following SCs of the RCS are within the scope of license renewal and are subject to an AMR: RCS piping (Class 1; non-Class 1 portions are addressed in Section 2.5 of the application), pressurizer, reactor vessel, reactor vessel internals, once-through steam generator, reactor coolant pumps, control rod drive motor tube housings, letdown coolers, Class 1 component supports, reactor coolant piping supports, pressurizer supports, reactor vessel support skirt, control rod drive service structure, once-through steam generator supports, and reactor coolant pump supports. The rest of this section lists the intended functions of these SCs according to 10 CFR 54.4(a) and briefly describes these SCs.

<u>Reactor Coolant System Piping (Class 1)</u>

Intended Function:

- Maintain primary pressure boundary so the RCS can perform its system functions.

For the ONS, the following components are within the reactor coolant pressure boundary: reactor vessel, once-through steam generators (primary side), pressurizer, reactor coolant pump, main coolant piping and portions of systems attached to these components. The attached systems that contain Class 1 components include the Core Flood System, High-Pressure Injection System, Low-Pressure Injection System, and Chemical Addition System. In addition, vents, drains, and instrumentation lines contain Class 1 components. RCS piping includes piping (including fittings, branch connections, safe ends, and thermal sleeves), valve bodies (pressure retaining parts of RCS isolation/boundary valves), and bolted closures and connections.

Pressurizer

Intended Functions:

- Maintain primary pressure boundary so the RCS can perform its system functions.
- Provide RCS pressure control.

The pressurizer is a vertical cylindrical vessel with a bottom surge line penetration connected to the hot leg piping by the surge line piping. The pressurizer contains electric heaters in its lower section and a water spray nozzle in its upper section. Since all sources of heat in the RCS are interconnected by piping with no intervening isolation valves, relief protection is provided on the pressurizer. Overpressure protection consists of two code safety valves and one power-operated relief valve. Piping attached to the pressurizer is Class 1 up to and including the first isolation valve.

Reactor Vessel

Intended Functions:

- Maintain the reactor vessel pressure boundary.
- Provide structural support for the reactor vessel internals and the reactor core.

The reactor vessel consists of the cylindrical vessel shell, lower vessel head, closure head, nozzles, interior attachments and all associated pressure-retaining bolting. Coolant enters the reactor through the inlet nozzles, passes down through the annulus between the thermal shield and vessel inside wall, reverses at the lower head, passes up through the core, turns around through the plenum assembly, and leaves the reactor vessel through the outlet nozzles.

The reactor vessel has two outlet nozzles, through which the coolant is transported to the steam generators, and four inlet nozzles, through which coolant enters the reactor vessel from the discharge of the reactor coolant pumps. Two smaller nozzles between the inlet nozzles serve as inlets for decay heat removal and emergency core cooling water injection. The reactor vessel is vented through the control rod drives. Instrumentation nozzles penetrate the lower vessel head.

Control rod drive mechanisms are attached to flanged nozzles, which penetrate the closure head, and are not within the scope of license renewal. However, the control rod drive motor tube housings are within the scope of license renewal and subject to an AMR.

Reactor Vessel Internals (RVI)

Intended functions:

- Support and orient the reactor core.
- Support, orient, guide, and protect the control rod assemblies.
- Provide a passageway to distribute the reactor coolant flow to the reactor core.
- Provide a passageway to support, guide, and protect incore instrumentation.
- Provide a secondary core support to limit downward displacement of core support structure.
- Provide gamma and neutron shielding.

The RVI consist of two structural subassemblies that are normally located within the reactor vessel. The RVI can be removed during refueling outages when necessary. The two subassemblies of the internals are the plenum assembly and the core support assembly. The RVI for the ONS are described in the B&WOG topical report, BAW-2248. The applicant states that it has reviewed the current design and operation of the ONS RVI, and has determined that they are bounded by the description in BAW-2248, with the exception of thermal shield and thermal shield upper restraint. The thermal shield and thermal shield upper restraint were omitted from the generic report; however, these items support an ONS RVI intended function and are subject to an AMR. The thermal shield surrounds the core barrel and is constructed of austenitic stainless steel. The thermal shield upper restraint is also constructed of austenitic stainless steel.

Once-Through Steam Generator (OTSG)

Intended Functions:

- Maintain primary pressure boundary so the RCS can perform its system functions.
- Provide decay heat removal under design basis conditions.

Each ONS unit has two OTSGs. Each is a vertical, straight-tube, once-through, counterflow, shell-and-tube heat exchanger with shell-side boiling. The steam generator consists of upper and lower hemispherical heads welded to tubesheets that are separated by a seven-course shell assembly. Over 15,000 straight Alloy 600 tubes are held in alignment by 15 tube support plates. Primary coolant from the reactor enters the steam generator through a single inlet nozzle in the top of the upper head. Coolant flows downward through the straight parallel tubes, is cooled by the secondary coolant on the shell side, and then exits through two outlet nozzles in the lower head. Secondary coolant enters through a ring of ports that penetrate the shell approximately midway up the shell assembly. The feedwater travels downward through an annulus between the lower baffle and the shell. Near the lower tubesheet the feedwater turns inward, and then flows upward around the tubes and through the tube support plates. As the feedwater absorbs heat from the primary coolant, it boils and then becomes superheated. The dry steam exits the steam generator through two steam outlet nozzles just above the feedwater inlet ports. The OTSG items that are subject to an AMR are the hemispherical heads, secondary shell, tubes, plugs, mechanical sleeves, tubesheets, primary nozzles, main and auxiliary feedwater nozzles, steam outlet nozzles, instrumentation nozzles, drain nozzles, all associated pressure retaining bolting, and integral attachments inspected in accordance with ASME Section XI, Subsections IWB and IWC.

Reactor Coolant Pumps (RCPs)

Intended Function:

- Maintain primary pressure boundary so the RCS can perform its system functions.

The reactor coolant pumps provide the head required to transport the reactor coolant through the reactor core, piping, and steam generators. All four reactor coolant pumps of each ONS unit are required during normal operation. The four reactor coolant pumps installed on ONS Unit 1 are Westinghouse Model 93A, while those installed on ONS Units 2 and 3 are Sultzer-Bingham.

The reactor coolant pump items that are subject to an AMR are the casing, cover, and associated pressure-retaining bolting. The portion of the reactor coolant pump rotating element above the pump coupling, the electric motor, and the flywheel are not subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The pump cover is a generic term used to describe the pressure-retaining closure of the pump casing. The cast austenitic stainless steel cover (stuffing box for Sultzer-Bingham pumps) serves as a housing for the mechanical seals, radial bearing, thermal barrier, and recirculating impeller for the Sulzer-Bingham pumps. The cover is clamped between the carbon steel driver mount (motor stand for Sulzer-Bingham pumps) and the stainless steel pump casing. The main flange serves as the cover for the Westinghouse design. The Westinghouse cover closure consists of the main flange, thermal barrier, and pump casing.

Each reactor coolant pump is supported by the cold leg piping during all modes of operation; the weight of each reactor coolant pump motor is supported by two vertical constant load supports.

Control Rod Drive Motor Tube Housing

Intended Function:

- Maintain primary pressure boundary so the RCS can perform its system functions.

Control rod drive mechanism motor tube housings provide the reactor coolant pressure boundary around the control rod drive mechanisms. During normal operation, the control rod drive mechanism motor tube housings are filled with borated reactor coolant at the system operating pressure. Thermal barriers in the lower-motor tube mechanism, the control rod drive mechanism cooling system, and vessel head cooling fans maintain the temperature in the housings below RCS temperature.

Two different designs of control rod drive mechanisms are currently in use at ONS: Type A at ONS Units 1 and 2, and Type C at ONS Unit 3. The control rod drive mechanisms themselves are active and not considered to be subject to an AMR for license renewal.

<u>Letdown Coolers</u>

Intended Function:

- Maintain primary pressure boundary so the RCS can perform its system functions.

The letdown coolers are used during normal operation to cool the letdown flow from the RCS to prevent damage to the purification system ion exchange resins. The coolers are of the shell and spiral tube design. Borated water from the RCS is on the tube side and treated water from the Component Cooling System is on the shell side. The tubes, tubesheets, and channel heads in the coolers are stainless steel and are within the scope of license renewal for the RCS. The cooler shell is carbon steel and is considered part of the Component Cooling System. Each unit has two letdown coolers.

<u>Class 1 Component Supports</u>

The following component supports are within the RCS evaluation boundary:

- RCS class1 piping supports
- Pressurizer supports
- Reactor vessel support skirt
- Control rod drive service structure
- OTSG supports
- RCP supports

<u>RCS Class 1 Piping Supports</u>

Intended Function:

- Provide support to the Class 1 components during design-basis events.

Supports associated with the RCS piping include standard unit pipe supports, LOCA restraints, and snubbers. Snubbers are active and are not subject to an AMR in accordance with 10 CFR 54.21(a)(1).

RCS piping supports provide structural and functional support of the Class 1 piping during seismic events in accordance with design basis loads. LOCA restraints provide structural support during seismic events and prevent pipe whip in the event of a postulated rupture of a pipe.

Class1 piping greater than 14-inch nominal pipe size (NPS) includes the 36-inch and 28-inch hot and cold leg piping. The hot and cold leg piping is supported by the once-through steam generator and the reactor vessel. Two LOCA restraints surround each hot leg: one at the 90-degree elbow that directs coolant flow to the vertical riser section, and the second that envelops the vertical riser. Each cold leg contains a LOCA restraint at the reactor coolant pump inlet. All LOCA restraints are shimmed so that a gap exists between the restraint and the piping during all modes of operation.

Class 1 piping less than or equal to 14-inch NPS includes the decay heat drop line, core flood/decay heat injection lines, pressurizer surge line, pressurizer spray and auxiliary spray lines, high-pressure injection/makeup lines, letdown lines, vent and drain lines, instrumentation lines, and In-core Monitoring System piping. Piping supports associated with these lines (with the exception of the pressurizer surge line, which is supported by the hot leg and the pressurizer) include the following standard support units: variable spring hangers, constant load supports, threaded rods with fasteners, pipe clamps, U-bolts, and swing sway braces. Items that support the intended function include the standard support units and the exposed portion of the connection to the building structure.

Pressurizer Supports

Intended Function:

- Provide support to the Class 1 components during design-basis events.

The pressurizer supports consist of the support plate assemblies, support frame assembly, and a LOCA restraint. The pressurizer support plate assemblies and the support frame assembly provide structural support for the pressurizer. The LOCA restraint minimizes the movement of the pressurizer following a postulated break of the surge line.

Eight support plate assemblies are welded to the exterior shell of the pressurizer and each support plate assembly is bolted to the support frame assembly. The support frame assembly is attached to and supported by the secondary shield wall. In addition, a LOCA restraint surrounds the pressurizer surge nozzle to limit motion of the vessel following a postulated rupture of the pressurizer surge line. The LOCA restraint is hung from the support frame assembly. One end of the LOCA restraint is clamped around the pressurizer surge nozzle and the other end is suspended with its end very close to the secondary shield wall.

The support plate assemblies are fabricated from carbon steel. Structural members that support the intended functions of the support frame assembly and LOCA restraint include beams, bracket, stiffeners, plates, hanger rods, and structural bolting. Support frame and LOCA restraint structural members are fabricated from carbon steel and alloy steel. In addition, the exposed portion of the connection to the building structure is within the scope and subject to an AMR.

Reactor Vessel Support Skirt

Intended Function:

- Provide support to the Class1 components during design-basis events.

The reactor vessel supports consists of a support skirt and support flange. The reactor vessel support skirt is a cylindrical structure that supports each reactor vessel. The support skirt rests on a sole plate, which is supported by a reinforced concrete pedestal and is fixed to the pedestal by a steel flange that is bolted to the pedestal by prestressed bolts. The evaluation boundary of the reactor vessel support skirt begins at the weld of the skirt to the reactor vessel transition forging and terminates at the bottom of the skirt flange. The evaluation boundary also includes the exposed surface of the anchor bolts and shear pins. The support skirt consists of two carbon steel semicircular rings welded together longitudinally to form a cylinder. This cylinder is welded to the bottom of the reactor vessel transition forging. The cylinder has holes for ventilation of the reactor vessel cavity. The anchor bolts are prestressed to accommodate the loads of a design basis seismic event.

Control Rod Drive Service Structure

Intended Function:

- Provide lateral support for the top of the control rod drive mechanisms so that proper alignment is maintained and the control rod insertion into the core will be achieved.

The control rod drive service structure is located on top of the reactor vessel and prevents excessive lateral motion of the control rod drive mechanisms to ensure that the control rods can drop into the core under design-basis loading conditions. The control rod drive service structure consists of five major assemblies:

- Lower Control Rod Drive Service Structure Skirt — A slotted carbon steel cylinder that is welded to the upper surface of the reactor vessel closure head. A mating flange is welded to the skirt and provides a seating surface to which the upper control rod drive service structure is bolted.

- Upper Control Rod Drive Service Structure Skirt — A carbon steel cylindrical shell with a lower flange that connects to the lower control rod drive service structure skirt and an upper flange that connects to the closure head service structure shell flange.

- Closure Head Service Structure Shell — A carbon steel cylinder that is attached to the upper control rod drive service structure skirt and supports the control rod drive service structure platform assembly.

- Control Rod Drive Service Structure Strut Support Assembly — Horizontal carbon steel beams oriented in a radial direction and welded to the closure head service structure shell on one end and supported on the other by angled beams.

- Control Rod Drive Service Structure Platform Assembly — A horizontal platform made of carbon steel beams that is attached to the top of the closure head service structure shell and the control rod drive service structure strut support assembly. The control rod drive service structure platform assembly restrains the top ends of the control rod drive mechanisms from lateral movement during design-basis loadings.

<u>OTSG Supports</u>

Intended Function:

- Provide support to the Class 1 components during design-basis events.

OTSG supports that are subject to an AMR include the support skirt and upper lateral support structure. The intended function of the steam generator support skirt is to transfer lateral and vertical loads from the OTSG to the reinforced steam generator foundation. The intended function of the upper lateral support structure is to provide support during seismic events (i.e, to transmit pipe rupture forces and dynamic forces to the secondary concrete shield wall).

The OTSG support skirt consists of a perforated alloy steel cylinder that is welded to a carbon steel support plate. Reinforcement of the joint that connects the cylinder to the support plate is provided through equally spaced carbon steel gusset plates that are welded to the inside of the cylinder and the support plate. The support plate has holes equally spaced around it. These holes match up with the anchor bolts embedded in the steam generator foundation which supplies the vertical support of the steam generator.

The steam generator support skirt is attached to the lower steam generator head by a rolled low-alloy steel plate transition ring, which is welded to the exterior of the lower head. For ONS Units 1 and 2, the support skirt is welded to the transition forging with full penetration welds. The transition ring at ONS Unit 3 is a low-alloy steel ring forging that is part of the lower head pressure boundary assembly and has a shaped transition that projects out to accept the support skirt attachment weld.

The upper lateral support structure surrounds each steam generator at the elevation of the upper tube sheet. The structure consists of five lateral support subassemblies that are attached to the secondary shield wall at five azimuthal locations surrounding the steam generator. Each subassembly extends from the secondary shield wall to the steam generator, and each subassembly is connected to an adjacent subassembly with tie plates. Attached to the end of each subassembly is a spring head that consists of a carbon steel backing plate, carbon steel shims, and a machined lubrite pad fabricated from bridge bearing bronze. The external face of each lubrite pad is concave and faces a convex carbon steel bearing plate that is bolted to the exterior shell of the steam generator. The bearing plates are machined to dimensions for the cold position and the lubrite pads are machined to dimensions for the hot position. The lubrite pads are shimmed in the field to ensure proper fit-up with the bearing plates during cold and hot conditions. The lateral support subassemblies and tie plates are fabricated from carbon steel and alloy steel fasteners.

All structural members used to construct the upper lateral support structure, including the exposed portion of the anchor bolts and nuts that connect the upper lateral support subassemblies to the secondary shield wall, are subject to an AMR.

<u>Reactor Coolant Pump Supports</u>

Intended Function:

- Provide structural and/or functional support to non-safety-related equipment where failure of this structural component could directly prevent satisfactory accomplishment of any safety-related function.

Reactor coolant pump supports consist of vertical support assemblies and lateral support assemblies. Two vertical support assemblies are provided for each reactor coolant pump motor. Each vertical assembly consists of: two coated constant load supports, two galvanized rods manufactured from alloy steel, and galvanized washers and nuts that connect the rods to the motor and the constant load support to the rods. The constant load supports are designed to accept the weight of the reactor coolant pump motor at normal operating temperature.

The reactor coolant pump lateral support assemblies include snubbers and turnbuckles. Snubbers are not subject to an AMR in accordance with 10 CFR 54.21(a)(1). However, the pins that connect the snubbers to the pumps and the secondary shield wall are within the scope and subject to an AMR. Turnbuckles (two per pump) limit lateral displacement of the pump and motor following a postulated LOCA. The RCP lateral support assemblies are subject to an AMR as shown in Table 3.4-1 of Exhibit A of the LRA.

2.2.3.2.1.2 Staff Evaluation

The NRC staff reviewed this section of the application to determine whether there is reasonable assurance that the RCS components and supporting structures subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). The staff's review is discussed below.

2.2.3.2.1.2.1 RCS Within the scope of License Renewal and Subject to an AMR

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs 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 UFSAR for the RCS, and compared the information in the UFSAR with the information in the application to identify portions that the applicant did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed SCs that the applicant did not identify, and as described below, requested the applicant provide additional information and/or clarifications for certain SSCs to verify that (1) they do not have any intended functions as delineated in 10 CFR 54.4(a), and if they do, that (2) they are either active components or are subject to replacement either at the end of qualified life or at specified intervals, as described in 10 CFR 54.21(a)(1). The staff also reviewed the UFSAR for any safety-related system functions that were not identified as intended functions in the application, to verify that no SCs having intended functions were omitted from consideration as being within the scope of the rule.

After completing the initial review, by letter dated November 30, 1998, the staff issued requests for additional information (RAIs) regarding the RCS, and by letters dated January 25, February 8, and February 17, 1999 the applicant provided responses to those RAIs. In RAI 2.4-1, the staff stated that drawings nos. OLRFD-107A-1.1, 2.1 and 3.1 of the LRA show the pressurizer quench tank with the sparger; but it was not clear from the drawings if the sparger nozzles are within the scope of license renewal. Therefore, the staff requested the applicant provide clarification. In response, the applicant clarified that sparger nozzles within the Coolant Storage System are within the scope of license renewal and subject to an AMR.

In RAI 2.4-2, the staff referenced page 4-51, Section 4.5.1.3.1, of the ONS UFSAR, which states that lifting lugs are provided for remote handling of the plenum assembly (reactor vessel internals), and that these lugs are welded to the cover grid. However, it was not clear from the LRA (Fig. 2.4-5) if these lifting lugs and attachment welds are within the scope of license renewal. The RAI requested the applicant discuss whether these items are within the scope or provide a basis for their exclusion. The applicant responded by stating that these lifting lugs are within the scope of license renewal and subject to an AMR.

In RAI 2.4-3, the staff referred to page 5-44, Section 5.3.1 of the UFSAR, which states that guide lugs are welded inside the reactor vessel lower head to limit a vertical drop of the reactor internals and core to ½-inch or less and prevent rotation about the vertical axis in the unlikely event of a major internals component failure. It was not clear from the LRA (Figs. 2.4-2, 3 and 4) if these lugs and attachment welds are within the scope of license renewal; therefore, the RAI sought clarification as to whether these items are within the scope of license renewal. The applicant stated in its response that the core guide lugs and their attachment welds are within the scope of license renewal and subject to an AMR.

In RAI 2.4-4, the staff referred to page 4-10, Section 4.2.2.1.5 of the UFSAR, which states that attached to the upper end fitting (reactor vessel internals) is a holddown spring, which provides a positive holddown margin to oppose hydraulic forces resulting from the flow of the primary coolant. It was not clear from the LRA (Fig. 2.4-5) if this spring is within the scope of license renewal; therefore, the RAI requested the applicant discuss whether this item is within the scope of license renewal or provide a basis for its exclusion. The applicant's response explained that the holddown spring is attached to the upper end fitting of the fuel assembly and is not attached to the reactor vessel internals, and that the end fittings are retired from service when the fuel assembly is replaced for refueling. The fuel assemblies and associated upper end fittings, including the holddown springs, are periodically replaced during refueling outages and are not subject to an AMR in accordance with 54.21(a)(1)(ii).

In RAI 2.4-5, the staff referred to page 5-43, Section 5.3.1, of the UFSAR, where it is stated that test taps are provided in the annulus between the two O-rings to afford a means to leak test the reactor vessel closure seal. It was not clear from the LRA (Figs. 2.4-2, 3, and 4) if these test taps are within the scope of license renewal. Therefore, the RAI requested the applicant discuss whether these test taps are within the scope of license renewal or provide a basis for their exclusion. The applicant responded that the test taps (also referred to as monitoring pipes) do not support a reactor vessel intended function and are not subject to an AMR.

In RAI 2.4-6, the staff pointed out that Figs. 2.4-2, 3, and 4 of the LRA show the reactor vessel; however, these figures do not show the closure head of the vessel. As a result, the RAI requested the applicant discuss if the following two device types are subject to an AMR: (1) lifting lugs and (2) vents that were added to the reactor vessel and to the pressurizer head in response to NUREG-0737, Item II.B.I. In response, the applicant stated that the reactor vessel lifting lugs do not support a reactor vessel intended function, and are not subject to an AMR; however, the reactor vessel head and the pressurizer vent lines are within the scope of license renewal and subject to an AMR.

Finally, in RAI 2.4-7, the staff requested the applicant explain Table 2.4-4 of the LRA, which lists RCS components and their intended functions. The staff asked the applicant to discuss why the following intended functions, for the specified components, were not considered as intended functions to be maintained for license renewal, and to provide bases. The components and their intended functions are given below:

Component	Intended Function(s)
Reactor Vessel Internals	Capability to shutdown the reactor and maintain it in a safe-shutdown condition.
OTSG	Provide heat removal under abnormal operating conditions.

In addition, the staff requested that the applicant verify that reactor coolant pumps do not have any intended functions, credited for design-basis events, that meet the requirements of 10 CFR 54.4, other than the intended function cited for license renewal, i.e., pressure boundary function of the pump casing and flow-related coastdown function associated with the RCP flywheel, and are therefore not considered within the scope. The applicant's response to the RAI was as follows:

Reactor Vessel Internals Intended Function — capability to shut down the reactor. The subject intended function has been defined by the applicant as a system level scoping function, and is not a component intended function, and therefore, not included as an intended function for the RVI. Furthermore, the addition of this function as an intended function would not subject any additional RVI items to an AMR.

OTSG Intended Function — provide heat removal under abnormal operating conditions. The OTSG intended functions as listed in the application are (1) maintaining the primary pressure boundary so the RCS can perform its system function, and (2) providing decay heat removal under design basis conditions. The second ONS OTSG intended function encompasses the NRC-specified function to provide heat removal under abnormal operating conditions. Design-basis calculations cover all modes of operation: i.e., normal, upset, emergency, and faulted.

Reactor Coolant Pump Intended Function. The applicant reviewed the ONS UFSAR and the RCS design-basis document and concluded that the only intended function of the RCP is the pressure boundary function as listed in the application, and that no additional intended functions were identified for the RCPs. The coastdown function of the RCP is required to mitigate selected design-basis events (e.g., loss-of-coolant flow accident in Chapter 15 of the UFSAR); however, the applicant determined that flow coastdown, which is a function of system resistance and flywheel inertia, is a system level function and not a component function. The time-limited aging analysis of the RCP flywheel is addressed in Section 5.4.4 of the application.

GSI-23 Reactor Coolant Pump Seal Failures

In Section 1.5.2 of Exhibit A of the LRA, Duke discusses GSI-23. GSI-23 deals with the high rate of reactor coolant pump seal failures that challenge the makeup capacity of the Emergency Core Cooling Systems in pressurized water reactors. The license renewal rule states that the application must identify and list those SCs subject to an AMR. The rule goes on to state that SCs subject to an AMR shall encompass those SCs that, among other things, are "not subject to replacement based on a qualified life or specified time period." The applicant stated, in Section 1.5.2 of Exhibit A of the LRA, that a license renewal AMR is not required for the RCP seals because they are routinely replaced. In subsequent documentation, dated February 17, 1999, the applicant stated that the RCPs are replaced in accordance with the "Engineering Support Program." Additionally, the seals "are replaced on an interval not to exceed every four operating cycles," for Units 2 and 3, which use Bingham manufactured RCPs, and for the first (of three) stage of the Unit 1 seals, which uses Westinghouse manufactured RCPs. The applicant went on to state that the second and third stages for the Unit 1 seals "are replaced on an interval not to exceed every two operating cycles." As a result, in accordance with 10 CFR 54.21(a)(1(ii) because the RCP seals are subject to replacement based on a qualified life or specified time period, the staff agrees that these seals are not subject to an AMR.

2.2.3.2.1.3 Review Findings for RCS

On the basis of the staff's review of the information provided in Sections 2.4.3 through 2.4.3.11 of the application, the supporting information in the ONS UFSAR, and the applicant's response to the staff's RAIs as discussed in the preceding section, 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 RCS and its supporting SCs that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.2.3.3 Engineered Safety Features Systems

2.2.3.3.1 Containment Heat Removal Systems

In Section 2.5.3, "Containment Heat Removal Systems," of Exhibit A of the LRA, the applicant identified the systems and components that are within the scope of license renewal and that are subject to an AMR. The Containment Heat Removal Systems include the Reactor Building Cooling System and the Reactor Building Spray System.

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.3.1.1 Summary of Technical Information in the Application

Reactor Building Cooling System (RBCS)

The RBCS is designed to provide cooling to the reactor building following a loss-of-coolant accident. The steam-air mixture within the reactor building passes over the cooling coils in one of three reactor building cooling units to transfer heat from the containment atmosphere to the Low-Pressure Service Water System.

The applicant described their process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. The applicant identified the portions of the RBCS that are within the scope of license renewal on flow diagrams listed on Table 2.5-2 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list in Table 2.5-3 of Exhibit A of the LRA. Four component types were identified as subject to an AMR, including three types of ductwork (aluminum, stainless steel, and galvanized steel) and reactor building cooling units. For these component types, maintaining the pressure boundary was identified as an intended function. Heat transfer was identified as an additional intended function for the reactor building cooling units.

Reactor Building Spray System (RBSS)

The RBSS is designed to remove heat from the containment atmosphere after a design-basis accident. The system also removes fission product iodine from the post-accident containment atmosphere. The RBSS consists of two redundant trains capable of taking suction from the header in the Low-Pressure Injection System and delivering borated water through the spray nozzles to the containment atmosphere during an accident. The borated water sprayed through the spray nozzles is collected in the reactor building sump and is recirculated for long-term cooling of the containment atmosphere.

The applicant described their process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. The applicant identified the portions of the RBSS that are within the scope of license renewal on flow diagrams listed in Table 2.5-2 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list on Table 2.5-3 of Exhibit A of the LRA. Six component types were identified as subject to an AMR: mechanical expansion joint, orifice, pipe, pump casing, spray nozzle, and valve bodies. For these component types, maintaining the pressure boundary was identified as an intended function. Two other intended functions, throttling and spraying, were identified for the orifice and spray nozzle.

2.2.3.3.1.2 Staff Evaluation

The staff reviewed Section 2.5.3, "Containment Heat Removal Systems," of Exhibit A of the LRA to determine whether there is reasonable assurance that the applicant has identified the Containment Heat Removal System components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.3.1.2.1 Containment Heat Removal Systems Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed Section 6.2.2, "Containment Heat Removal Systems," of the UFSAR and compared the description of the systems and other components in the UFSAR to the description in the application to determine if the applicant should have identified any additional portions of the system as within the scope of license renewal. As described in Sections 2.5.3 of Exhibit A of the LRA, essentially all portions of the Containment Heat Removal Systems were determined to be within the scope of license renewal and subject to an AMR. Two exceptions, as addressed below, are RBCS ductwork downstream of the dropout plates and the RBCS piping that directs condensate to the reactor building sump. The staff reviewed the remaining components of the containment heat removal systems to verify that they do not perform any intended functions. The staff also reviewed Section 6.2.2 of the UFSAR to determine whether the applicant failed to identify any additional functions as intended functions in the LRA. The staff found no omissions. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the Containment Heat Removal System that fall within the scope of license renewal and are subject to an AMR in accordance with 10 CFR Part 54.

In RAI 2.5.3-1, the staff questioned why the RBCS piping and ductwork that supply cooling air to the steam generator cavity and reactor vessel annulus and direct condensate to the reactor building sump were not included within the scope of license renewal. The piping and ductwork in question are shown on Flow Diagrams OLRFD-116E-1.1, 2.1, and 3.1. The staff requested the applicant verify that the above functions were not credited in any safety analyses. Specifically, the applicant was asked to discuss its assumptions as to (1) initial or normal operating temperature assumed in the steam generator cavity and reactor vessel annulus for the purpose of equipment qualification, (2) normal operating temperature assumed to support the integrated exposure before a 10% reduction in sensitivity for the out-of-core neutron detectors, and (3) reactor building sump inventory.

In response to RAI 2.5.3-1, the applicant reaffirmed that the RBCS piping and ductwork that supply air to the steam generator cavity and reactor vessel annulus and direct condensate to the reactor building sump are not credited with supporting any system function as defined in 10 CFR 54.4(a). The applicant then addressed the three assumptions the staff requested information about. Temperature measurements in the steam generator and reactor vessel cavities are recorded and trended on an ongoing basis. If temperatures rise substantially above normal operating ranges for a period of time, that period of time at high temperatures is evaluated for impact on the established average ambient temperatures used in the qualified life calculations. The 10% reduction in sensitivity for the out-of-core neutron detectors is primarily a function of neutron flux intensity and not temperature. Calibration of the nuclear instrumentation system would detect any change in sensitivity and/or inability to meet performance requirements and the detector would be replaced per established procedures. Finally, reactor building sump inventory analyses do not rely on the water supplied by the RBCS condensate drain to the reactor building normal sump. Because the RBCS ductwork and piping are not credited with supporting a function defined in 10 CFR 54.4 (a) or (b), the applicant has justified not including this ductwork and piping within the scope of license renewal.

Section 9.4.6.2 of the ONS UFSAR states that in the event of a LOCA the RBCS fusible links melt, which assures a positive path for recirculation of the reactor building atmosphere. In RAI 2.5.3-2, the staff questioned why the fusible links were not included as one of the RBCS components subject to an AMR in Table 2.5-3 of Exhibit A of the LRA. In response to RAI 2.5.3-2, the applicant stated that the fusible links are considered within the scope of license renewal but are not subject to an AMR, in accordance with 10 CFR 54.21, because they change state (melt) to perform their intended function. The staff reviewed the information provided by the applicant and found it acceptable.

Section 15.15.1 of the ONS UFSAR states that the RBSS is credited with removal of a portion of the remaining iodine from the building atmosphere. In RAI 2.5.3-6, the staff questioned whether this intended function had been addressed by Exhibit A of the LRA. In response to RAI 2.5.3-6, the applicant stated that sodium hydroxide is credited with the removal of iodine following a postulated design-basis event. A portion of the chemical addition system is used to inject the sodium hydroxide and is within the scope of license renewal and subject to an AMR. The portion of the chemical addition system responsible is found on flow diagrams OLRFD-110A-1.8, 2.8, and 3.8. The applicant further stated that these flow diagrams were inadvertently omitted from Table 2.5-10 of Exhibit A of the LRA. The AMR for these components is found in Section 3.5.7.1of Exhibit A of the LRA. Based on the applicant's response to RAI 2.5.3-6, the staff finds the above intended function of the RBSS adequately addressed by Exhibit A of the LRA.

2.2.3.3.1.3 Review Findings for Containment Heat Removal Systems

As described above, the staff has reviewed the information provided in Section 2.5.3 of Exhibit A of the LRA and the additional information provided by the applicant in response to the staff's

RAIs. Based on this review, the staff has reasonable assurance that the applicant has appropriately identified those portions of the Containment Heat Removal Systems, and components thereof, that are 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.

2.2.3.3.2 Containment Isolation System

In Section 2.5.4, "Containment Isolation System," of Exhibit A of the LRA, the applicant identified portions of the system and the components therein that are within the scope of license renewal, and identified which of those within-scope components are subject to an AMR.

Component (equipment and piping)supports for the system are presented separately in Section 2.6 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.7 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant included instrument line components with the system to which they are attached.

2.2.3.3.2.1 Summary of Technical Information in the Application

The Containment Isolation System is an engineered safety feature that provides for the closure of all fluid penetrations not required for operation of the engineered safeguards system to prevent the leakage of uncontrolled or unmonitored radioactive materials to the environment.

The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the Containment Isolation System that are within the scope of license renewal on flow diagrams listed on Table 2.5-4 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list in Table 2.5-5 of Exhibit A of the LRA. Ten component types were identified as subject to an AMR: pipe, valve bodies, orifice, hose connection, tubing, air flow monitor, annubar, ductwork, filter, and grill. For these component types, maintaining the pressure boundary was identified as the intended function. Two other intended functions, throttling and filtration, were identified for the orifice and filter.

2.2.3.3.2.2 Staff Evaluation

The staff reviewed Section 2.5.4 of Exhibit A of the LRA to determine whether there is reasonable assurance that the applicant has identified the Containment Isolation System components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.3.2.2.1 Containment Isolation System Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed Section 6.2.3, "Containment Isolation System," of the UFSAR and compared the description of the system and components in the UFSAR to the description in the application to determine if the applicant should have identified any additional portions of the system as within the scope of license renewal and subject to an AMR. The plant's containment isolation valves are listed in Figure 6-9 of the UFSAR. In RAI 2.5.4-1, forwarded by a letter dated December 1, 1998, the staff asked the applicant to clarify whether all the containment isolation valves listed in Figure 6-9 of the UFSAR are subject to an AMR. In a letter dated February 8, 1999, the applicant responded to the RAI and stated that all the containment isolation valves listed in Figure 6-9 are within the scope of license renewal and subject to an AMR.

The staff also reviewed Section 6.2.3 of the UFSAR for any safety-related functions that may not have been identified as an intended function by the applicant in Exhibit A of the LRA. The staff performed this review to identify any structure or component having a safety related function (that is performed without moving parts, or without a change in configuration or propertied, and that is not subject to replacement) that may not have been correctly determined to be subject to an AMR. The staff found no omissions in the SCs selected by the applicant as requiring an AMR.

2.2.3.3.2.3 Review Findings for Containment Isolation System

As described above, the staff has reviewed the information provided in Section 2.5.4 of Exhibit A of the LRA and the additional information provided by the applicant in response to the staff's RAI. Based on this review, the staff has reasonable assurance that the applicant has appropriately identified those portions of the Containment Isolation System, and the associated components thereof, that are 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(a)(1).

2.2.3.3.3 Emergency Core Cooling Systems

In Section 2.5.5, "Emergency Core Cooling Systems," of Exhibit A of the LRA, the applicant identified the SCs of the Emergency Core Cooling Systems (ECCSs) that are within the scope and subject to an AMR for license renewal.

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.3.3.1 Summary of Technical Information in the Application

As described in the LRA, ECCSs are designed to cool the reactor core and provide shutdown capability following design-basis accidents. The following systems of the ECCS are included by the applicant as within the evaluation boundary for license renewal:

- Core Flood System
- High-Pressure Injection System
- Low-Pressure Injection System

<u>Core Flood (CF) System</u>

The following components of the CF System are within the scope of license renewal, and are subject to an AMR: tank, pipe, tank nozzle, tubing, and valve bodies. The intended function for these components, based on the requirements of 10 CFR 54.4(a) is listed as pressure boundary.

The CF System is designed to inject water directly into the reactor vessel when the RCS pressure drops below a certain level following an accident. The CF System is self-contained, self-actuating, and passive in nature. During power operation, when the RCS pressure is higher than the CF System pressure, check valves (bodies only) located between the reactor vessel CF nozzles and the CF tanks prevent high-pressure reactor coolant from entering the CF tanks. The driving force to inject the stored borated water into the reactor vessel is supplied by a pressurized nitrogen cover in the CF tanks. After an accident, when the RCS pressure decreases below the nitrogen cover pressure, the contents of the CF tanks will be injected directly into the reactor vessel.

<u>High-pressure Injection (HPI) System</u>

The following components of the HPI System are within the scope of license renewal, and are subject to an AMR: demineralizer, filter, flexible hose, flow meter, flow nozzle, mechanical expansion joint, orifice, pipe, pump casing, tank, tubing, valve bodies, reactor coolant pump (RCP) coolers (Units 2 and 3), and RCP seal return coolers.

The intended functions for these components based on the requirements of 10 CFR 54.4(a) are listed as pressure boundary and throttle.

The HPI System operates during normal reactor operation to recirculate reactor coolant for purification and to supply seal water to the RCPs (casings). Letdown flow is directed to the letdown storage tank, which provides suction flow to the operating HPI pump. The letdown storage tank is normally supplied with a hydrogen overpressure. The HPI pump supplies water directly to the RCS by way of the normal charging header and also supplies seal injection water to the RCPs (casings).

During emergency operation, the HPI System automatically supplies borated water directly to the reactor vessel injection nozzles on low RCS pressure or high reactor building pressure. The HPI System also supplies borated water to the RCP seals. The water added directly to the system makes up for water lost from a primary-side leak or from a "shrink" in reactor coolant volume due to cooling caused by a secondary-side break.

Low-Pressure Injection (LPI) System

The following components of the LPI System are within the scope of license renewal, and are subject to an AMR: annubar, decay heat removal coolers, orifice, pipe, pump casing, tank (borated water storage), tubing, and valve bodies. The intended functions for these components, based on the requirements of 10 CFR 54.4(a), are listed as pressure boundary, throttle, and heat transfer.

The LPI System is used during cold shutdown and refueling operations to remove decay heat. During power operation, the system is idle. This system is also part of the ECCS and supplies cooling water to the reactor after intermediate and large loss-of-coolant accidents.

During unit cooldown, the reactor coolant temperature and pressure are reduced by way of the steam generators. At approximately 250 °F and 300 psig, the LPI System is placed in service. Reactor coolant is drawn from the RCS through the decay heat drop line and is cooled by the decay heat removal coolers and returned to the RCS. The decay heat removal coolers have pressure boundary and heat transfer functions.

Upon initiation of an accident, the LPI System takes suction from the borated water storage tank and injects the tank contents into the reactor vessel. When the borated water storage tank level becomes low, system suction is manually transferred to the reactor building emergency sump.

Water from the sump is cooled by the decay heat removal coolers and reinjected into the reactor vessel.

2.2.3.3.3.2 Staff Evaluation

The staff reviewed Section 2.5.5 of the application to determine whether there is reasonable assurance that the ECCS components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished as discussed below.

2.2.3.3.3.2.1 ECCS Within the Scope of License Renewal and Subject to an AMR

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs 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 UFSAR for the ECCS, and compared the information in the UFSAR with the information in the application to identify portions that the applicant did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed SCs outside the applicant-identified portion, and as described below, requested that the applicant submit additional information or clarifications or both for a selected number of SCs to verify that (1) they do not have any intended functions as delineated in 10 CFR 54.4(a) and, if they did, to verify that (2) they are either active components or 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 UFSAR for any safety-related system functions that were not identified as intended functions in the application to verify that all SCs having intended functions were not omitted from consideration within the scope of the rule.

After completing the initial review, by letter dated November 30, 1998, the staff issued requests for additional information (RAIs) regarding the ECCS, and by letters dated January 25, February 8, and February 17, 1999, the applicant provided responses to those RAIs. In RAI 2.5.5-1, the staff made reference to page 6-38, Section 6.3.2.5 of the UFSAR, where it is indicated that all components with surfaces in contact with water containing boric acid are protected from corrosion and deterioration. With the exception of the borated water storage tank (BWST), the major components in the LPI System are constructed of stainless steel. The BWST is made of carbon steel with an interior phenolic coating to protect it from corrosion and deterioration. In the RAI, the staff requested that the applicant clarify whether the coating is relied upon to ensure the intended function of the BWST for the period of extended operation. If it is, then the applicant was asked to describe the program to maintain the coating; and if not, then to present the basis for its exclusion. The applicant responded that the internal coating of the BWST is a physical design feature of the tank. Loss of material from the carbon steel shell was determined to be an applicable aging effect for the tank given a carbon steel and borated water material/environment combination. The aging effect is managed by inspecting the BWST internal coatings during preventive maintenance activities. This inspection will manage the effect of loss of material from the tank by monitoring the condition of the inside of the tank, including the coating. The staff's review of the applicant's program is discussed in Section 3.2.10 of this SER.

In RAI 2.7-5, the staff indicated that during the ONS license renewal scoping and screening process overview meeting held on October 1, 1998, the staff was informed that tanks (including the vertical tanks erected in the field) are considered to be mechanical components. However, the tank foundation and anchorage systems are considered structural components. With regard to the scoping process for the vertical tanks, the staff requested that the applicant address the following concerns:

a. a basis for not including tank supports in the discussion of Section 2.7.2, "Structural Components," in the application

b. the definition of the boundary (or interface) between tanks (mechanical components) and tank supports (structural components), which are usually welded to the tanks

In a response to RAI 2.7-5, the applicant stated the following:

a. Tank supports are not uniquely identified as components but are included in the category of equipment component supports listed in Section 2.7.2 of the application.

b. The boundary (or interface) between the tanks and the tank supports is at the weld of the support to the tank. The weld is included with the tank in the AMR.

Regarding Duke's February 8, 1999, response to RAI 2.7-5(a), the staff agreed with the applicant's categorization of the anchorage systems of the field-erected vertical tanks as steel equipment component supports (as stated on page 2.7-5 of the application). However, vertical tanks can have tank foundations that are made of concrete rather than steel (e.g., BWST). The staff questioned if these tank foundations were considered to be within the scope of license renewal.

As documented in a June 2, 1999, phone call summary Duke responded that vertical tanks such as the BWST are included in mechanical scope. The tanks' foundations or pads are included in Oconee license renewal scope in Section 2.7.2.1. The BWST foundation is located in the Yard and included within the category of equipment pads in Table 2.7-8. The staff also notes that the BWST foundation was identified in the license renewal basis document (OSS-0274.00-00-0007), which was reviewed on-site by the NRC during the scoping and screening inspection that occurred from April 26 through April 30, 1999.

In RAI 2.5.5-2, the staff indicated that boric acid solution is stored in heated and insulated tanks and is piped in heat-traced and insulated lines to preclude precipitation of the boric acid. In the RAI, the staff requested that the applicant clarify whether the insulation material is within the scope of license renewal, and if it is not, to identify the basis for its exclusion. The applicant responded that the tanks within the scope of license renewal in the ECCS are the letdown storage tank (LST), the core flood tank (CFT), and the BWST. The LST stores RCS letdown and provides suction to the HPI System, which is normally in service. Thus, temperatures are high enough that it is not necessary to heat and insulate the tank to prevent boron precipitation. The CFTs store borated water for use during an accident. These tanks are located in the reactor building so that temperatures are high enough that it is not necessary to heat and insulate the tank to prevent boron precipitation. The BWST stores borated water for emergency systems for accident conditions. These tanks are located in the yard and are heated and insulated in order to preclude boron precipitation. Additionally, the associated piping that is located in the yard is heat traced and insulated for the same purpose. The heaters, heat tracing, and insulation are designed to maintain the BWST inventory above the minimum technical specification (TS) temperature during normal operation. As a result of monitoring and maintaining the TS temperature limits, any heater failure or excessive heat loss from these tanks and pipes can be detected in time, and corrective actions can be taken to maintain the required boron concentration. The insulation, therefore, need not be within the scope of license renewal, and is not subject to an AMR.

As a follow up question, the staff requested the applicant, by letter dated December 14, 1999, to clarify why insulation need not be within the scope of license renewal; particularly, to clarify the basis on which the applicant concluded that the insulation is not relied on to ensure that the emergency systems will maintain a safe-shutdown condition or mitigate the consequences of design-basis events. In response, the applicant provided the following technical justifications:

a) Failure of the insulation during and following a design-basis event would not prevent the ECCS suction piping from performing its function during and following a design-basis event. Although, no quantitative calculation exists to support this statement, a review of boron solubility curves from Chemistry procedures (the Chemistry procedures are associated with Duke's Chemistry Control Program which is discussed in Section 4.6 of Exhibit A of the LRA) indicate that the temperature at which the boron precipitation may occur is well below the minimum temperature allowed by TS. The relative short period of time that the ECCS suction piping is in use post-accident is not long enough to allow boron precipitation, even at winter ambient temperatures.

b) A review of the design and operational aspects of the ECCS suction piping and BWST was performed by the applicant to provide additional information regarding boron precipitation in the event the insulation were to fail before an event. The design of the 14" diameter ECCS suction piping includes heat tracing that is thermostatically controlled at 50 F. The 20 to 30 feet of piping between the tank and the auxiliary building is routed in a covered yard trench and is insulated. The BWST heaters are controlled at approximately 60 F. The BWST boron concentration requirement varies based on core operating limits, but a 3000 ppm limit is used as a bounding, worst-case value. Boron concentration limits are required to be verified every 7 days according to TS. According to boron solubility curves in Chemistry procedures, for a concentration of 3000 ppm, boron will not precipitate from solution until water temperatures falls below 22 F. It is not considered plausible for the water temperature in the tank or the ECCS suction piping to reach 22 F, primarily because TS require that the BWST borated water temperature be maintained between 45 F and 115 F. When the ambient temperature is less than 45 F or greater than 115 F, the tank temperature is required to be verified every 24 hours using a temperature monitor near the bottom of the tank. If borated water temperature inside the BWST falls outside the limit, it must be returned to an acceptable temperature within 8 hours in order to continue unit operation.

c) Notwithstanding the TS limit, it is considered physically impractical that the water in the ECCS suction piping would ever reach 22 F. The ambient outside air temperature rarely gets below 22 F, and the tank heaters and heat tracing are thermostatically controlled at 60 F and 50 F, respectively. Even if the heat tracing were to fail and all of the insulation were to fail in a manner that rendered it completely useless, simple heat transfer equations reveal that it would take several days for the water in a 14" diameter pipe to reach 22 F, assuming the piping is completely exposed to a constant ambient temperature of 20 F. This assumption is conservative because ECCS suction piping is routed below ground level in a covered yard trench that serves as insulation to the ambient temperature and wind. The temperature of the piping in the trench should be approximately ground temperature, which stays well above 20 F.

d) An additional operational aspect to consider is that water flows from the BWST through the ECCS suction piping approximately twice per week for purification purposes, quarterly for low pressure injection pump testing, and every refueling outage to empty the contents of the tank. Therefore, neither the water in the tank nor the water in the ECCS suction piping remains stagnant for long periods of time.

The justifications provided above clarifies the applicant's basis for concluding that the insulation at Oconee is not relied upon to ensure that the emergency systems will maintain a safe-shutdown condition or mitigate the consequences of design-basis events. Based on the above information, the applicant reaffirms the accuracy and validity of its response to RAI 2.5.5-2 previously provided in its letter dated February 17, 1999. The staff considers the applicant's assessment and the conclusion acceptable.

In RAI 2.5.5-3, because the containment sump suctions to the ECCS pumps are enclosed by particulate screens, whose intended function is to prevent debris from entering the pumps, the staff requested that the applicant clarify whether these screens are within the scope of license renewal; and if they are not, to identify the basis for their exclusion. The staff also requested a discussion of the intended functions these items might perform for license renewal. The applicant responded by stating that the containment sump screens are within the scope of license renewal and are subject to an AMR. The intended function of the sump screens, which has been listed in Table 2.7-5 of the application, is to provide structural or functional support or both to safety-related equipment. The applicant further clarified that providing functional support encompasses preventing debris from entering the pumps.

In RAI 2.5.5-4, the staff requested that the applicant clarify if the flow restriction orifices are within the scope of license renewal; and if they are not, to identify the basis for their exclusion. The RAI also requested a discussion of the intended functions these items might perform for license renewal. The applicant's response was that Section 2.5.5 of the application, "Emergency Core Cooling System," covers the HPI System, the LPI System, and the CF System. No orifices are within the license renewal portions of the CF System. The orifices within the license renewal portions of the HPI System and the LPI System are within the scope of license renewal and are subject to an AMR. All orifices in the HPI and LPI Systems have a component-intended function of pressure boundary. Some orifices have the component-intended function of throttling to limit mass flow rate. Some orifices are required to throttle flow for flow rate measurement.

Finally, the staff issued RAI 2.5.5-5 to obtain clarification of flow diagrams OLRFD-103A-1.1, 2.1, and 3.1 that are referenced in the LRA, which shows the LPI System that supplies water to the Reactor Building (containment) Spray System. The RAI asked whether the nozzles in this spray system are within the scope of license renewal; and if not, to identify the basis for their exclusion. The response from the applicant was that the reactor building spray nozzles are within the scope of license renewal and are subject to an AMR.

2.2.3.3.3.2.2 Review Findings for the ECCS

On the basis of the staff's review of the information contained in Sections 2.5.5 of the application, the supporting information in the ONS UFSAR, and the applicant's response to the staff's RAI as discussed in the preceding section, 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 ECCS and its associated components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.2.3.4 Auxiliary Systems

2.2.3.4.1 Auxiliary Systems

In Section 2.5.6, "Auxiliary Systems," of Exhibit A of the LRA, the applicant described the auxiliary systems and identified the SSCs that are within the scope of license renewal. Auxiliary systems are generally located in the auxiliary building and they included the following systems: Spent Fuel Cooling System (SFCS), Auxiliary Service Water (ASW) System, Condenser Circulating Water (CCW) System, High-Pressure Service Water (HPSW) System, and Low Pressure Service Water (LPSW) System. From these systems, the applicant also identified those within-scope SCs that are subject to an AMR.

In a letter to the staff dated September 30, 1999, the applicant amended the SSCs included within the scope of license renewal as a result of revising the Steam Generator Tube Rupture

Accident (SGTRA) analysis to include portions of the Component Cooling System (CC). The revised SGTRA analysis adds the additional system function of transferring heat from the reactor coolant pump thermal barriers, but does not affect other portions of the LRA.

Component (equipment and piping) supports for the systems listed above are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the systems are presented in Section 2.6, "Electrical Components," of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of the SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, rules for identifying components within the scope of license renewal in OLRP-1002 specifically state that instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow. The applicant included instrument line components with the system to which they are attached.

2.2.3.4.1.1 Summary of Technical Information in the Application

Spent Fuel Cooling (SFCS) System

The primary functions of the SFCS are to remove decay heat from the spent fuel stored in the spent fuel pool (SFP), to maintain clarity and chemistry of the water in the pool at acceptable levels, and to transfer water within the systems. The Oconee Nuclear Station has two SFPs; one pool stores spent fuel from Units 1 and 2, and the second pool stores spent fuel from Unit 3. Each pool has an independent SFCS. Each SFCS consists of three coolant pumps, three parallel coolers, bypass flow through a demineralizer, and filters that remove soluble ions and insoluble particulates, and various piping, valves, and instrumentation. The Recirculating Cooling Water (RCW) System supplies cooling water flow to the spent fuel coolers.

The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.5.2, "Detailed Process Description," of Exhibit A of the LRA. The applicant determined that the cooling and purification functions of the SFCS do not provide any design-basis-event mitigation functions that warrant including the system within the scope of license renewal. However, there are other plant functions that interface with the SFCS that perform design-basis-event mitigation, fire protection functions, and station blackout functions. These portions of the SFCS are within the scope of license renewal. In addition, because the cooling and purification portions of the SFCS are seismically designed Class B and C piping and provide design margin against loss of inventory of the system and the spent fuel pool, the applicant considers this piping within the scope of license renewal. As a result, essentially all piping and components in the SFCS are within the scope of license renewal.

On the basis of its methodology described above, the applicant identified the portions of the SFCS that are within the scope of license renewal on flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2, "Identification of

Mechanical Components Subject to an Aging Management Review," of Exhibit A 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 listed these in Table 2.5-9 of Exhibit A of the LRA. The applicant identified the following 11 component types as subject to an AMR: pipe, pump casing, demineralizer, filter, flexible hose, orifice, spent fuel transfer tube, tank, tubing, valve bodies, and spent fuel coolers. The applicant identified maintaining the pressure boundary as the only intended function for these components.

Auxiliary Service Water (ASW) System

The ASW System is designed to remove decay heat from all three units simultaneously, assuming the concurrent loss of each unit's main feedwater, emergency feedwater, and LPI Systems. Loss of these systems can be postulated as a result of a tornado. The system also serves as a backup source of cooling water for the high-pressure injection pump motor coolers. Lake water is supplied to the ASW System through the Unit 2 CCW System's intake pipes. During normal plant operation, the ASW System is not operating, and manual isolation valves on the suction discharge and minimum flow piping are closed. The discharge header supplies all three units and is isolated from the six steam generators by several closed check valves and closed, manually operated gate valves. The ASW System piping is designed and constructed to the requirements of Oconee System Piping Class F. The system is designed to withstand a design-basis earthquake without a loss of function.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the ASW System that are within the scope of license renewal on flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA. The applicant identified essentially all of the components in the ASW System as being within the scope of license renewal. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 listed the components and their intended functions in Table 2.5-9 of Exhibit A of the LRA. The following 7 component types were identified as subject to an AMR: two types of piping, pump casing, tubing, annubar tube, and two types of valve bodies. The applicant identified maintaining the pressure boundary, and for the annubar tube, throttling, as the intended functions for these components.

Condenser Circulating Water (CCW) System

The CCW System utilizes lake water that serves as the ultimate heat sink during normal operation and for decay heat removal during plant cooldown. This system also supplies cooling water to various pieces of plant equipment and is the suction source for other cooling water systems, including the Low-Pressure Service Water System. Each unit has four CCW pumps that supply water through two 11 foot-diameter conduits into a common condenser intake header. The CCW System is also designed to operate using a siphon lineup to the Keowee hydro tailrace, should a loss-of-power occur.

In a letter to the staff dated October 15, 1999, as a result of adding portions of the Chilled Water System to the scope of license renewal, the applicant amended the LRA to include those portions of the CCW System that remove heat from the Chilled Water System. The Chilled Water System that provides cooling water to the Control Room Ventilation System is evaluated in Section 2.2.3.4.10 of this SER. Prior to this amendment, removing heat from the Chilled Water System was not an intended function of the CCW System, therefore, this portion of the CCW System was not within the scope of license renewal.

The portions of the CCW System within the scope of license renewal are Oconee System Piping Class D, F, and G. The CCW pumps and intake piping to the low-pressure service water pumps, through the condenser and emergency CCW discharge piping, are Class D or F. The Class F portions of the system are designed to withstand a design-basis earthquake without loss of function. The Class D portions of the system are designed to maintain pressure boundary and structural integrity based on the potential for interaction with other systems during a design-basis earthquake. Portions of the CCW within the scope of license renewal and constructed of Oconee Piping Class G are designed to USAS B31.1.0 and are not designed for seismic loading.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the CCW System that are within the scope of license renewal on flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA and in Section 2 of Attachment 2 of the letter dated October 15, 1999. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list in Table 2.5-9 of Exhibit A of the LRA and in Table 2 of Attachment 2 of the letter dated October 15, 1999. The following 14 component types were identified as subject to AMR: four types of tubing, annubar tube, flexible hose, and two each of the following component types - strainers, piping, pump casings, and valve bodies. The applicant identified maintaining the pressure boundary, and for the annubar tube, throttling, as the intended functions for these components.

High-Pressure Service Water (HPSW) System

The HPSW System supplies water to fire protection sprinkler systems, hose stations, fire hydrants, and deluge systems throughout the plant and plant site (excluding the reactor building and the Keowee station). The system also supplies sealing or cooling water to many plant components. Two motor-driven large-capacity pumps and one motor-driven small-capacity pump, together with the elevated water storage tank, deliver a reliable supply of water for the system. The pumps and elevated water storage tank discharge into a common header that distributes the water supply throughout the plant.

The HPSW System piping inside any structures or buildings and the piping at the CCW intake structure are typically Oconee System Piping Class G. Only portions of the HPSW System designated as Class F piping are capable of withstanding a design-basis earthquake without loss of function.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the HPSW System that are within the scope of license renewal on flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA. The applicant identified essentially all of the components in the HPSW System as being within the scope of license renewal. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list in Table 2.5-9 of Exhibit A of the LRA. The following 21 component types were identified as subject to an AMR: three types of piping, pump casings, four tubing types, filters, four types of valve bodies, fire hydrants, two hose rack types, two types of mechanical expansion joints, mulsifyers, sprinklers and strainers. The applicant identified maintaining the pressure boundary, and for the sprinklers, spray, as the intended functions for these components.

Low-Pressure Service Water (LPSW) System

The LPSW System supplies cooling water for normal and emergency services throughout the ONS. The LPSW System distributes cooling water to the following safety-related equipment: the reactor building cooling units, low-pressure injection coolers, high-pressure injection pump motor bearing coolers, turbine-driven emergency feedwater pump bearing cooling jackets, and the motor-driven emergency feedwater pump motor air coolers. In addition, the LPSW System supplies various non-safety-related systems and components with cooling, sealing, makeup, fire protection, flush, and backwash capabilities. The system shares two pumps for Units 1 and 2, and has two pumps for Unit 3, plus the necessary piping, valves, instrumentation, and other components. Water is supplied to the LPSW System by gravity or siphon flow following a design-basis event in which CCW pumps are not assumed to be operating. Safety-related portions of the LPSW System identified in the flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA are designated as Oconee System Piping Class F.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the LPSW System that are within the scope of license renewal on flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA. The applicant identified essentially all of the components in the LPSW System as being within the scope of license renewal. Using the methodology described in Section 2.5.2.2 of the LRA, the applicant compiled a list (Table 2.5-9 of Exhibit A) of mechanical components and component types, and the associated intended functions that are within the evaluation boundaries and subject to an AMR. The following 24 component types were identified as subject to an AMR: two types of piping, pump casing, four tubing types, annubar tube, two filter types, three types of valve bodies, component coolers, two strainer types, two site glass types, orifice, two types of mechanical expansion joints, two hose rack types, and flex hose. The applicant identified maintaining the pressure boundary, and for the annubar tube, throttling, as the intended functions for these components. Filtering and throttling were also identified as intended functions for filters and orifices.

In a letter dated September 30, 1999, the applicant added the Reactor Building Auxiliary Coolers to the list of components subject to AMR. These coolers had been omitted from the original application because they were isolated from LPSW System flow due to operability issues and, therefore, did not perform an intended function under 10 CFR Part 54. The applicant resolved the operability issues regarding the coolers, returned the coolers to service, and have included the coolers within the scope of license renewal and subject to AMR. The applicant identified maintaining the pressure boundary as the intended function for these components.

Component Cooling (CC) System

The CC System provides cooling water to various components in the Reactor Building, including the control rod drives, letdown heat exchangers, quench tank coolers, and the reactor coolant pump coolers and jackets. Initially, only those portions of the CC System associated with the containment isolation function were included within the scope of license renewal. In a letter dated September 30, 1999, the applicant revised the application to include those portions of the CC System that provide cooling water to the reactor coolant pump coolers and jacket. This revision was made because of modifications made to the SGTRA analysis.

The applicant described its process for identifying the mechanical components within the scope of license renewal and subject to AMR in Section 2.5.2 of Exhibit A of the LRA. On the basis of this methodology, the applicant identified the portions of the CC System that are within the scope of license renewal in a letter dated September 30, 1999. The staff requested and the applicant provided additional clarification regarding the portions of the CC System within the scope of license renewal, including highlighted flow diagrams of the CC System. The applicant identified essentially all of the components in the CC System as being within the scope of license renewal. The applicant compiled a list of the mechanical components within the license renewal boundaries that are subject to an AMR and identified their intended functions. The applicant presented the list in Table 2-1 of Attachment 1, to the September 30, 1999, letter. The following 19 component types were identified as subject to AMR: filters, two types of flexible hose, orifices, two types of piping, pump casings, tanks, three types of tubing, two types of valve bodies, heat exchanger channel head, heat exchanger shell, two types of heat exchanger tubes, and two types of heat exchanger tubesheets. The applicant identified maintaining the pressure boundary, and for the heat exchanger tubes, heat transfer, as the intended functions for these components.

2.2.3.4.1.2 Staff Evaluation

The staff reviewed Section 2.5.6 of Exhibit A of the LRA and the letters dated September 30, and October 15, 1999, to determine whether there is reasonable assurance that the applicant appropriately identified the auxiliary system components within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review of the LRA, the staff issued RAIs regarding the information submitted by the applicant for the auxiliary systems in a letter dated December 2, 1998. The applicant responded to those RAIs by letters dated January 25, February 8, and February 17, 1999. The staff did not issue RAIs after reviewing the September 30 and October 15, 1999, letters from the applicant, but did request clarifying information from the applicant, as documented in the staff memorandum dated November 18, 1999.

2.2.3.4.1.2.1 Auxiliary System Components Subject to an Aging Management Review

The staff reviewed the text and diagrams submitted by the applicant in Section 2.5.6 of Exhibit A of the LRA, the applicant's letter dated September 30, and October 15, 1999, and the ONS UFSAR to identify if there were portions of the system piping and other components that the applicant did not identify as within the scope of license renewal that performed intended functions. Essentially all portions of the auxiliary systems perform at least one intended function and, therefore, essentially all portions and components of the auxiliary systems are within the scope of license renewal and are identified as such by the applicant in Section 2.5.6 of Exhibit A of the LRA. For scoping systems and structures, the staff focused its review on those SCs of the auxiliary systems that were not identified as being within the scope of license renewal to verify that they do not have any intended functions that meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified as intended functions in the LRA and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4. As described in detail below, with respect to each system, the staff found no omissions by the applicant. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the auxiliary systems that fall within the scope of license renewal in accordance with 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the components subject to an AMR from among those identified as within the scope of license renewal. The applicant listed the SCs subject to an AMR for the auxiliary systems in Table 2.5-9 of Exhibit A of the LRA using the screening methodology described in Section 2.5.2 of Exhibit A of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. As described in more detail in the following subsections, the staff sampled from the list of SCs for each auxiliary system identified by the applicant as subject to an AMR, to get reasonable assurance that all components subject to an AMR were appropriately identified. 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 a configuration change or were subject to replacement on the basis of a qualified life or a specified time period (i.e., active or short-lived).

Spent Fuel Cooling System

In the LRA, the applicant listed seven detailed flow diagrams OLRFD-102A1.1, 2.1, 3.1, 104A-1.1, 1.2, 3.1, and 3.2 of the SFCS in Table 2.5.8 of Exhibit A of the LRA and listed the mechanical components subject to an AMR and their intended functions in Table 2.5-9 of Exhibit A. The applicant highlighted the detailed flow diagrams to identify those portions of the 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 system drawings and descriptions in the UFSAR to ensure they were representative of the SFCS. The staff sampled portions of the flow diagrams that were not highlighted to ensure that these components did not perform any intended functions defined in 10 CFR 54.4. Based on this review, the staff issued RAIs regarding several components in the SFCS (NRC letter dated December 2, 1998), and by letters dated January 25 and February 8, 1999, the applicant responded to those RAIs. Specifically, the staff asked in RAIs 2.5.6-1 and 2.5.6-2 whether the SFP transfer tube isolation valve and blank flange closure plate were in the scope for license renewal. Neither were indicated as being within the scope on the system flow diagrams. The applicant responded that the diagrams were wrong and that the components were within the scope for license renewal and were identified in Table 2.5-9 of Exhibit A of the LRA as valves and piping.

The staff also asked in RAI 2.5.6-14 about the intended functions of the following components: filter, orifice, and spent fuel cooler. Pressure boundary was the only intended function listed in the LRA; however, these components perform other functions, such as filtering, throttling, and heat exchange. The applicant responded that only those intended functions of the listed components that support the system intended function as required by 10 CFR 54.4(a), are listed in Table 2.5-9. The staff reviewed the system intended functions for the SFCS and agreed with the applicant that, maintaining the pressure boundary is the only intended function of the orifice and filter that meet the requirements of 10 CFR 54.4, and that should be listed for those components on Table 2.5-9.

However, in Section 2.2 of this SER, the staff identified an open item regarding the omission of the RCW System from within the scope of license renewal. The RCW System supplies cooling water to the spent fuel coolers, which were identified by the applicant as being within the scope of license renewal. The staff reviewed this issue and documented its closure in Section 2.2.3 of this SER. On the basis of this review, the staff determined that the SFCS performs only a pressure boundary function, and that heat transfer was not an intended function of the spent fuel coolers required by 10 CFR 54.4.

On the basis of a review of the LRA, supporting information in the UFSAR, and the applicant's responses to the staff's RAI concerning those components not within the scope of license renewal, the staff has reasonable assurance that the applicant has identified all portions of the SFCS on the flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA with intended functions meeting the criteria in 10 CFR 54.4 as being within the scope of license renewal.

Using the information presented on the flow diagrams for the SFCS in Table 2.5-8 of Exhibit A, 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 in Table 2.5-9 of Exhibit A from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams appeared in the list of components subject to an AMR for the SFCS in Table 2.5-9 of Exhibit A. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the SFCS subject to an AMR.

Auxiliary Service Water System

The applicant listed the detailed flow diagram OLRFD-121D1.2 for the ASW System in Table 2.5-8 of Exhibit A of the LRA and identified the mechanical components subject to an AMR and their intended functions in Table 2.5-9. The applicant highlighted the detailed flow diagram to identify those portions of the 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 system drawings and descriptions in the UFSAR to ensure they were representative of the ASW System.

Essentially all of the ASW System was highlighted, indicating it was within the scope of license renewal. 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 UFSAR, the staff has reasonable assurance that all portions of the ASW System with intended functions meeting the criteria in 10 CFR 54.4 are identified as being the within the scope of license renewal on the flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA.

Using the information on the flow diagrams for the ASW in Table 2.5-8 of Exhibit A, 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 in Table 2.5-9 of Exhibit A from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams appeared on the list of components subject to an AMR for the ASW System in Table 2.5-9 of Exhibit A. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the ASW System subject to an AMR.

Condenser Circulating Water System

The applicant listed 15 detailed flow diagrams OLRFD-124B1.1, 2.1, 3.1, 133A-1.1, 1.2, 1.3, 1.4, 1.5, 2.1, 2.2, 2.3, 3.1, 3.2, 3.3, and 3.4 of the CCW System in Table 2.5-8 of Exhibit A of the LRA and identified the mechanical components subject to an AMR and their intended functions in Table 2.5-9. The applicant highlighted the detailed flow diagrams to identify those portions of the 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 system drawings and descriptions in the UFSAR to ensure they were representative of the CCW System. The staff sampled portions of the flow diagrams that were not highlighted to ensure that these components did not perform any intended functions defined in 10 CFR 54.4. Based on this review, the staff issued RAIs regarding several components in the CCW System (NRC letter dated December 2, 1998), and by letters dated January 25 and February 8, 1999, the applicant responded to those RAIs. Specifically, the staff asked in RAI 2.5.6-3 whether valves 2CCW-438 and -246 were within the scope of license renewal, since neither valve was indicated as being within the scope of license renewal on the detailed system flow diagrams. The applicant responded that the diagrams were wrong and that the components were within the scope for license renewal and were listed in Table 2.5-9 of Exhibit A of the LRA under the "valves" category. The staff also asked in RAI 2.5.6-14 about the intended functions of the following components: orifice and RCW heat exchanger. Pressure boundary was the only intended function listed in the LRA; however, these components perform other functions, such as throttling and heat exchange. The applicant responded that only those intended functions of the listed components that support the system intended function required by 10 CFR 54.4 are listed in Table 2.5-9. The staff reviewed the system intended function for the CCW System and agreed with the applicant that the orifice only performs a pressure boundary function.

However, in Section 2.2 of this SER, the staff identified an open item regarding the omission of the RCW System from within the scope of license renewal. The applicant identified the RCW coolers, which transfer spent fuel decay heat to the CCW System, as being within the scope of license renewal because they are part of the within-scope CCW System. However, maintaining the pressure boundary was the only intended function identified for this component. Because the RCW System removes decay heat from the SFP coolant and transfers it to the CCW System, which maintains SFP temperature below 150°F to support the UFSAR Chapter 15 fuel handling accident analysis assumptions, the staff considered heat transfer as an intended function for the RCW coolers during its evaluation of this system. This issue was identified as Open Item 2.2.3-1. The applicant responded to the open item in letters dated October 15, and November 30, 1999. The staff reviewed and accepted the applicant's justification for omitting the RCW system from the scope of license renewal and documented their decision in Section 2.2.3 of this report.

In a letter dated October 15, 1999, the applicant amended the initial LRA to include portions of the CCW System that provide heat removal from the Chill Water System chillers that support the Control Room Ventilation System. The applicant listed the additional CCW components subject to an AMR on Table 2 of Attachment 2 to the October 15, 1999, letter. The staff reviewed flow diagrams OFD-133A-1.1 and 124A-1.2 to identify those portions of the CCW System that performed the revised intended function of transferring heat from the Chilled Water System. The staff sampled components from the flow diagrams that were considered not within the scope of license renewal to ensure the components did not perform any intended functions defined in 10 CFR 54.4. Based on this review, the staff did not identify any components outside the license renewal boundary that performed intended functions within the scope of license renewal. However, the staff asked the applicant to clarify the system designations associated with the components that provide cooling water to the Chilled Water System chillers. On diagram OFD-124A-1.2, the applicant highlighted portions of the LPSW System that provide cooling to the chillers. Since the applicant indicated in their October 15, 1999, letter that the piping and components that provide cooling to the chillers were part of the CCW System, the staff asked the applicant to clarify the boundaries and system designations of this support system. In addition, the staff asked the applicant to verify that flooding would not be a concern for a section of the LPSW System in the process flow that was not designated as being within the scope of license renewal. This piping performed no intended function as defined by 10 CFR 54.4, but could cause flooding if severe leakage occurred. As documented in an NRC memorandum dated November 18, 1999, the applicant stated that even though the components have LPSW designations, they are considered part of the CCW System because they support a CCW System function (providing cooling water to the Chilled Water System chillers). The applicant also addressed the flooding concern stating that the piping is located in the Turbine Building, away from safety-related equipment, and would have been classified Oconee Piping Class D had failure of the pressure boundary affected the function of safety-related equipment. The staff reviewed the applicant's responses and concluded that classifying portions of the LPSW in this manner was acceptable for license renewal because the SCs subject to an AMR were identified and listed in accordance with 10 CFR 54.21. In addition, based on the applicant's assessment that failure of the subject piping will not affect the function of safety-related equipment, the staff concluded that the CCW System scoping boundary is acceptable.

On the basis of a review of the LRA, the applicant's letter dated October 15, 1999, supporting information in the UFSAR, and the applicant's responses to the staff's RAI concerning components outside the scope of license renewal, the staff has reasonable assurance that all portions of the CCW System with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal on the flow diagrams listed in Table 2.5-8 of Exhibit A of the LRA and described in Attachment 2 of the applicant's letter dated October 15, 1999.

Using the information on the flow diagrams for the CCW System (Table 2.5-8 of Exhibit A, flow diagrams OPD-124A-1.2 and 133A-1.1), the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components in the list of components as subject to an AMR (Table 2.5-9 of Exhibit A, and Table 2 of Attachment 2 of the applicant's letter dated October 15, 1999) from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams were in the list of components subject to an AMR for the CCW System in Table 2.5-9, and Table 2 of Attachment 2 of the applicant's letter dated October 15, 1999. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the CCW System subject to an AMR.

High-Pressure Service Water System

The applicant listed 14 detailed flow diagrams OLRFD-124C-1.1, 1.2, 1.3, 1.4, 1.6, 2.2, 2.3, 2.6, 3.2, 3.3, 3.6, 133A-1.1, 2.1, and 3.1 of the HPSW System in Table 2.5-8 of Exhibit A of the LRA and identified the mechanical components subject to an AMR and their intended functions in Table 2.5-9. The detailed flow diagrams were highlighted to identify those portions of the system within the scope of license renewal. The applicant highlighted those components that perform at least one intended function meeting the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and descriptions in the UFSAR to ensure they were representative of the HPSW System. The staff sampled portions of the flow diagrams that were not highlighted to ensure that these components did not perform any intended functions defined in 10 CFR 54.4.

Based on this review, the staff issued RAIs regarding several components in the HPSW System (NRC letter dated December 2, 1998), and by letters dated February 8 and 17, 1999, the applicant responded to these RAIs. Specifically, the staff asked in RAI 2.5.6-9 whether the following components identified on the system flow diagrams but not listed in Table 2.5-9 for the HPSW System were within the scope of license renewal: the HPSW pump motor air coolers, flow restricting orifices, annubar tubes, the elevated storage tank, and quick disconnects. In its response to RAI 2.5.6-9, the applicant stated that two components (orifices and annubar tubes) had been inadvertently left off the list and that a revised Table 2.5-9 listing the two components was submitted in response to RAI 4.16-11. The staff reviewed the revised Table 2.5-9 and found that it contained the components and was, therefore, acceptable. The applicant also clarified that the elevated water tank is considered a structure, is within the scope of license renewal and subject to an AMR, and is described in Section 2.7.10.3 of Exhibit A of the LRA and listed on Table 2.7-8. Similarly, quick disconnects are encompassed by the commodity group "pipe" and are included with this group on Table 2.5-9. The staff reviewed Tables 2.7-8 and 2.5-9 and found the components listed appropriately. The applicant stated in their response to RAI 2.5.6-9 that the HPSW motor air coolers are within the scope of license renewal, however, the coolers are not subject to an AMR because they are considered to be sub-components of the motor. The staff does not agree that these components can be excluded from an AMR. A similar condition exists for skid mounted components on the SSF diesel described in

Section 2.2.3.4.8.2.1 of this SER. The staff reviewed the methodology which the applicant used in its IPA to exclude these components (i.e., the motor air coolers) from an AMR, and found that it was not consistent with Section 4.1.1, "Establishing Evaluation Boundaries," of the Nuclear Energy Institute's 95-10, "Industry Guide for Implementing the Requirements of 10 CFR 54 - The License Renewal Rule," or Example 5 of Appendix C of 95-10. This issue was being tracked by open item 2.2.3.4.8.2.1-1 in the June 1999, version of this report. See Section 2.2.3.4.8.2.1 of this report for the discussion regarding the resolution of this item.

The staff also asked in RAI 2.5.6-14 about the intended functions of the following components: filter, mulsifier, and strainer. Pressure boundary was the only intended function listed in the LRA; however, these components perform other functions, such as filtering. The applicant responded that only those intended functions of the listed components that support the system intended function required by 10 CFR 54.4 are listed in Table 2.5-9. The staff reviewed the applicant's response and the information contained in the LRA and the UFSAR concerning the components' intended functions and agrees with the applicant that maintaining the pressure boundary is the only intended function of the filter, mulsifyer, and strainer that meets the requirements of 10 CFR 54.4. Therefore, the staff finds the omission of these intended functions from Table 2.5-9 acceptable.

On the basis of a review of the LRA, the supporting information in the UFSAR, and the applicant's responses to the staff's RAI the staff has reasonable assurance that all portions of the HPSW System with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal on the flow diagrams listed in Table 2.5-8 of Exhibit A.

Using the information on the flow diagrams for the HPSW System in Table 2.5-8 of Exhibit A, 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 in Table 2.5-9 of Exhibit A from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams were included on the list of components subject to an AMR for the HPSW System in Table 2.5-9. No omissions were identified. On the basis of this review the staff has reasonable assurance that the applicant has identified the components of the HPSW System subject to an AMR.

<u>Low-Pressure Service Water System</u>

The applicant listed 25 detailed flow diagrams OLRFD-100A-1.3, 2.3, 3.3, 121C-1.1, 124A-1.1, 1.2, 1.3, 2.3, 3.1, 3.3, 124B-1.1, 1.2, 1.4, 1.5, 1.6, 2.1, 2.2, 2.4, 3.1, 3.2, 3.4, 3.6, 133A-1.1, 2.1, and 3.1 of the LPSW System in Table 2.5-8 of Exhibit A of the LRA and identified the mechanical components subject to an AMR and their intended functions in Table 2.5-9. The applicant highlighted detailed flow diagrams to identify those portions of the system within the scope of license renewal. The applicant highlighted on each flow diagram those components that perform at least one intended function meeting the scoping requirements of 10 CFR 54.4. The staff compared the LRA flow diagrams to the system drawings and descriptions in the

UFSAR to ensure they were representative of the LPSW System. The staff sampled components on the flow diagrams that were not highlighted to ensure that these components did not perform any intended functions defined in 10 CFR 54.4. Based on this review, the staff issued RAIs regarding several components in the LPSW System (NRC letter dated December 2, 1998), and by letters dated January 25 and February 8, 1999, the applicant responded to those RAIs. Specifically, the staff asked in RAI 2.5.6-12 whether certain piping identified on the system flow diagrams but not highlighted as within the scope of license renewal had any intended functions. In the response to RAI 2.5.6-12, the applicant stated that the piping (LPSW cooling water return from the high-pressure injection pump motor cooler) is not required. Analysis indicated that only the cooling water supply to the pump motor coolers was required for the pump to perform its intended function. The staff reviewed the applicant's response and agreed that, based on the applicant's analysis, the LPSW cooling water return from the high pressure injection pump motor cooler does not perform an intended function as defined in 10 CFR 54.4 and is, therefore, not within the scope of license renewal.

The staff also asked in RAI 2.5.6-14 about the intended functions of the following components: filter, annubar tube, component coolers, and strainer. Pressure boundary was the only intended function listed in the LRA; however, these components perform other functions, such as filtering and heat exchange. The applicant responded that only those intended functions of the listed components that support the system intended function required by 10 CFR 54.4 are listed in Table 2.5-9. The applicant did identify that for the component filter, the filter intended function was listed in Table 2.5-9. The staff reviewed the applicant's response and the information contained in the LRA and the UFSAR and agreed that the annubar tube, component coolers, and strainers do not perform an intended function, other than maintaining pressure boundary, that meets the requirements of 10 CFR 54.4. Therefore, the staff finds the omission of these intended functions from Table 2.5-9 acceptable.

In response to the applicant's September 30,1999, letter adding the Reactor Building Auxiliary Coolers to the list of components subject to an AMR, the staff reviewed flow diagrams OLRFD 124B-1.3, 2.3, and 3.3, to ensure the applicant included all of the components supporting the Reactor Building Auxiliary Cooler pressure boundary for each unit. No omissions were identified.

On the basis of a review of the LRA, supporting information in the UFSAR, the applicant's letter dated September 30, 1999, and the applicant's responses to the staff's RAIs, the staff has reasonable assurance that all portions of the LPSW System with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal on the flow diagrams listed in Table 2.5-8 of Exhibit A.

Using the information on the flow diagrams for the LPSW in Table 2.5-8 of Exhibit A, 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 in Table 2.5-9 of Exhibit A, from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams were on the list of components subject to an AMR for the LPSW System in Table 2.5-9 or Table 3-1 of the applicant's letter dated September 30, 1999. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the components of the LPSW System subject to an AMR.

Component Cooling System

In their letter dated September 30, 1999, the applicant incorporated a revision to the Steam Generator Tube Rupture Accident analysis that assumes operation of the reactor coolant pumps will be available for a period of time after the accident occurs. Operation of the reactor coolant pumps requires component cooling water to the pump's thermal barriers. The applicant revised the intended functions of the CC System and identified the mechanical components subject to an AMR and their intended functions in Table 2-1 of the September 30, 1999, letter to the NRC. The list of components in Table 2-1 expanded the original list of components subject to an AMR identified in Section 2.5.4.2 of the LRA.

The staff reviewed system flow diagrams OFD-144A-1.1, 1.4, 2.1, 3.1, OLRFD-144A-1.3,2.3, and 3.3 and compared the components listed in Table 2-1 of the letter dated September 30, 1999, to the system flow diagrams to ensure those CC System components required to remove heat from the reactor coolant pumps were identified on the list of components within the scope of license renewal and subject to an AMR. The staff asked the applicant to clarify the status of the following component types not found on Table 2-1: heat exchangers (the Quench Tank Heat Exchanger, and the Letdown Coolers) and stator water jackets.

As documented in NRC memorandum dated November 18, 1999, the applicant responded that the stator water jackets should have been identified as a component within the scope of license renewal, but not subject to an AMR because the stator water jackets are subcomponents of the control rod drive mechanisms which are not subject to AMR in accordance with 10 CFR 54.21(a)(1)(i). The staff reviewed this conclusion and agreed with the applicant that the stator water jackets are not subject to AMR. After further review, the applicant concluded in a letter dated December 17, 1999, that the Quench Tank Heat Exchanger, and the Letdown Coolers were also within the scope of license renewal and subject to an AMR.

On the basis of a review of the applicant's letter of September 30, 1999, the system flow diagrams, and the applicant's responses to staff questions regarding the components within the scope of license renewal documented in the staff's memorandum dated November 18, 1999, and the applicant's response dated December 17, 1999, the staff has reasonable assurance that all portions of the CC System with intended functions meeting the criteria of 10 CFR 54.4 are identified as being within the scope of license renewal.

Using the information on the flow diagrams of the CC System OFD-144A-1.1, 1.4, 2.1, 3.1, OLRFD-144A-1.3, and 2.3, the staff sampled several components from Table 2-1 to determine whether the applicant properly identified the passive, long-lived components on the list of components subject to an AMR from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components on the system flow diagrams were on the list of components subject to an AMR for the CC System in Table 2-1 of the applicant's September 30, 1999, letter. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the SCs of the CC System subject to an AMR.

2.2.3.4.1.2.2 Review Findings for Auxiliary Systems

On the basis of the staff's review of the information in Section 2.5.6 of the application, the supporting information in the ONS FSAR, and the applicant's responses to the staff's RAIs as discussed in the preceding section, 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) SCs that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.2.3.4.2 Process Auxiliaries

In Section 2.5.7, "Process Auxiliaries," of the LRA, the applicant described the SCs of the process auxiliaries that are within the scope and subject to an AMR for license renewal.

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.2.1 Summary of Technical Information in the Application

As described in the LRA, the process auxiliary systems are required to support the reactor during normal operation. These systems are generally located within the auxiliary building. The following systems of the Process Auxiliaries are included by the applicant as within the evaluation boundary for license renewal:

- Chemical Addition System
- Coolant Storage System

Chemical Addition System

The following components of the Chemical Addition System are within the scope of license renewal, and are subject to an AMR: accumulator, expansion coil, flexible hose, orifice, pipe, pump casing, tubing, and valve bodies. The intended function for these components, based on the requirements of 10 CFR 54.4(a), are listed as pressure boundary.

The Chemical Addition System is designed to mix, store, and inject chemicals into the RCS and auxiliary systems. The system also functions as a central location for sampling various fluids throughout the plant to ensure chemical concentrations are maintained within the prescribed limits.

The portion of the Chemical Addition System used to draw samples from the secondary side of the steam generators is exposed to a treated water internal environment. The portion of the system used to draw samples from the primary side of the steam generators and the pressurizer steam and water spaces is exposed to a borated water internal environment. The Chemical Addition System external surfaces are exposed to the reactor building and auxiliary building environments.

Coolant Storage System

The following components of the Coolant Storage System are within the scope of license renewal, and are subject to an AMR: pipe, spray nozzles, tubing, and valve bodies. The intended function for these components, based on the requirements of 10 CFR 54.4(a), is listed as pressure boundary.

The Coolant Storage System is used for the collection and storage of reactor coolant liquid. The liquid is received from the high-pressure injection system as a result of reactor coolant expansion during startup and for boric acid concentration reduction during startup and normal operation. Coolant is stored in coolant bleed holdup tanks or is processed through deborating demineralizers for boric acid removal and returned to the High-Pressure Injection System as unborated makeup. Liquid from the coolant bleed holdup tanks is pumped to the coolant treatment system for processing. The quench tank, located inside the reactor building, condenses and contains effluent from the pressurizer safety valves (bodies only), power-operated relief valves (bodies only), and various vents and drains.

2.2.3.4.2.2 Staff Evaluation

The staff reviewed this section of the application to determine whether there is reasonable assurance that the process auxiliaries components subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished as discussed below.

2.2.3.4.2.2.1 Process Auxiliaries Within the Scope of License Renewal and Subject to an AMR

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs 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 UFSAR for the process auxiliaries, and compared the information in the UFSAR with the information in the application to identify portions that the applicant did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed SCs outside the applicant identified portion, and as described below, requested that the applicant submit additional information or clarifications or both for a selected number of SCs to verify that (1) they do not have any intended functions as delineated in 10 CFR 54.4(a) and, if they did, verify that (2) they are either active components or 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 UFSAR for any safety-related system functions that were not identified as intended functions in the application to verify that all SCs having intended functions were not omitted from consideration within the scope of the rule.

After completing the initial review, by letter dated November 30, 1998, the staff issued requests for additional information (RAIs) regarding the process auxiliaries, and by letters dated January 25 and February 8, 1999, the applicant responded to those RAIs. In RAI 2.5.7-1, the staff made reference to Table 2.5-11 of the application, which lists the components in the process auxiliaries and their intended functions. In the RAI, the staff requested that the applicant explain why the intended function "ability to spray water as designed" was not considered as an intended function to be maintained for license renewal. The applicant responded that the spray nozzles under consideration here are in the Coolant Storage System. This portion of the Coolant Storage System is within the scope of license renewal because it meets the criteria of 10 CFR 54.4(a)(3). This system is relied upon to meet the requirements of 10 CFR 50.48. During certain fire events, the Coolant Storage System routes releases from the RCS relief valves (used to control RCS pressure) to the quench tank where the spray nozzles are located. The releases from the relief valves flash to steam due to the high temperature of the RCS. The component function to spray the steam into the quench tank is not required in support of the system function to route this release to the quench tank. Therefore, "ability to spray water as designed" is not an intended function for the purpose of license renewal, and the staff agrees with the applicant's conclusion.

In RAI 2.5.7-2, the staff indicated that flow restriction orifices are installed in several pipes within the evaluation boundary for process auxiliaries in order to limit the mass flow rate during an accident. The RAI requested that the applicant clarify which of these orifices are within the scope of license renewal, and also to discuss the intended functions these items might perform for license renewal. In response, the applicant mentioned that the process auxiliaries include the chemical addition and Coolant Storage Systems. No orifices are within the license renewal portion of the Coolant Storage System. The orifices within the license renewal portions of the Chemical Addition System are within the scope and subject to an AMR. These orifices provide pressure boundary and throttle flow for flow measurement. Flow measurement is not required in support of the system-intended functions within the scope of license renewal. Therefore, the only component-intended function of the orifices that the applicant listed is pressure boundary.

2.2.3.4.2.2.2 Review Findings for Process Auxiliaries

On the basis of the staff's review of the information contained in Section 2.5.7 of the application, the supporting information in the ONS UFSAR, and the applicant's response to the staff's RAIs as discussed in the preceding section, 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 process auxiliaries and the associated (supporting) components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.2.3.4.3 Heating, Ventilation, and Air Conditioning Systems (HVAC)

In Section 2.5.8, "Air Conditioning, Heating, Cooling and Ventilation Systems," of Exhibit A of the LRA, the applicant identified portions of the auxiliary building ventilation system, the control room pressurization and filtration system, and the penetration room ventilation system, and the components that are within the scope of license renewal and identified which of those "within-scope" components are subject to an AMR. The applicant stated In Section 2.5.8 of Exhibit A of the LRA that HVACS are further described within Section 9.4 of the UFSAR. The HVACS consist of the following systems that are within the scope of the license renewal:

- Auxiliary Building Ventilation System (ABVS)
- Control Room Pressurization and Filtration System (CRPFS)
- Penetration Room Ventilation System (PRVS)

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.3.1 Summary of Technical Information in the Application

<u>Auxiliary Building Ventilation System (ABVS)</u>

The ABVS consists of the ABVS proper and the hot machine shop. Air is supplied to the auxiliary building by a low-pressure fan duct system. Air is taken in through outside air intake louvers by supply units consisting of roughing filters, steam coil, and cooling coil supplied by low-pressure service water. Six main supply fans are required for normal plant operation. Temperatures are maintained in the auxiliary building by throttling steam to the steam coils or low-pressure service water to the cooling coils as required. Exhaust fans exhaust air from the auxiliary building through the exhaust duct and through three unit vent stacks, where it is monitored before being released to the atmosphere. Under normal operating conditions, the ABVS supply fans and exhaust fans are balanced so that the exhaust air flow exceeds the supply air flow in order to minimize outleakage.

Air is supplied to the hot machine shop by two recirculating local cooling units. Each unit consists of roughing filters, a compressor, evaporator and condenser coils, and a centrifugal fan. These units supply recirculated air with a small amount of makeup air throughout the hot machine shop via a low-pressure duct system. Temperatures are maintained in the hot machine shop by electric unit heaters in the supply ductwork. The hot machine shop uses direct expansion cooling. Air is exhausted from the hot machine shop via an exhaust duct and a filter train and is discharged to the atmosphere through an independent vent stack.

Remote recirculating fan-coil-type units provide standby spot cooling in the pump rooms and other high heat load areas. The fan coil units are also served by the LPSW System.

The ONS Units 1 and 2 purge fan to remove smoke from the cable rooms and equipment rooms is located in the ONS Unit 2 equipment room wall to purge smoke to the auxiliary building corridor where it can be monitored and exhausted to the unit vent through ABVS equipment. The ONS Unit 3 purge fan is located on auxiliary building elevation 838'-0" with HVAC equipment, and would exhaust to that area enabling the ABVS to pick up, monitor, and discharge products of combustion through the plant vent.

In Section 2.5.8 of Exhibit A of the LRA and Section 9.4 of the UFSAR, the applicant identified the following intended functions for the ABVS based on 10 CFR 54.4(a)(1) and (2):

Section 2.5.8 of Exhibit A of the LRA -

- To maintain the auxiliary building at a negative pressure with respect to the turbine building and the outside atmosphere so that any potential contamination will be monitored and discharged through the unit vent; and

- To maintain the auxiliary building temperature within certain limits.

Section 9.4 of the UFSAR -

- To provide a suitable environment for the operation, maintenance, and testing of equipment and also for personnel access;

- To maintain temperature limits in all areas of the auxiliary building served by the system during normal plant operation of 104 °F and 60 °F during summer and winter, respectively, with the exception of the control room area and the penetration rooms;

- To direct the flow path of the ventilation air in the auxiliary building from clean or low activity areas toward areas of progressively higher activity;

- To direct all exhaust air from the auxiliary building to the unit vent stacks and to continuously monitor by a radiation monitor, that alarms on high radiation levels; and

- To provide air sampling throughout the auxiliary building areas served by the system by a radiation monitor with detector output logged on a recorder in the control room.

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

Section 2.5.8 of Exhibit A of the LRA -

- To provide ventilation in support of the ONS response to fire events.

Section 9.4 of the UFSAR -

- To provide an exhaust path for ONS Units 1, 2, and 3 fire events through the ABVS;
- To provide monitored exhaust to the unit vent.

Control Room Pressurization and Filtration System (CRPFS)

The CRPFS is designed to maintain the environment in the control areas of ONS Units 1, 2, and 3 which consists of the control room (common control room for ONS Units 1 and 2), cable rooms, and electrical equipment rooms within acceptable limits for the operation of unit controls as necessary for equipment and operating personnel. The control room envelope consists of the control room, offices, computer rooms, operators' break area, and operators' toilet room. Redundant air conditioning and ventilation equipment is provided to assure that no single active failure within these systems will prevent proper environmental control in the control area.

The ONS Units 1 and 2 control areas are served by four air handling units (AHUs). The control room is primarily served by two AHUs. Each unit has 100 percent capacity and only one unit is required to operate at a time. Cooling is provided to the Unit I cable room, Unit 2 cable room, Unit I equipment room, and Unit 2 equipment room by a total of four AHUs.

The ONS Unit 3 control areas are served by six AHUs. Two 100 percent AHUs serve the control room, two 100 percent AHUs serve the cable room, and two 100 percent AHUs serve the electrical equipment room.

The chilled water for the AHUs is supplied from the plant Chilled Water System, which is capable of supplying sufficient chilled water for all necessary systems with one of two chillers in service.

For pressurization purposes, outside air is supplied to the common control room for Units 1 and 2, and the control room for Unit 3 from an intake on the roof of the auxiliary building to offset the exfiltration from the control room zone. This minimizes uncontrolled infiltration into the control room zone by creating a positive pressure with respect to adjacent zones. Air passes through filter trains, which consist of pre-filters, 99.5 percent efficient high-efficiency particulate air (HEPA) filters, 90 percent efficient charcoal filter beds, and a centrifugal fan. Units 1, 2, and 3 control room filter systems are served by two 50 percent filter trains, and the system is capable of operating with one or both trains. The filter trains are manually started by the plant operators. When a radiation monitor in the return air intake of the AHUs alerts the operators in the control room to a high radiation reading, the operators start the outside-air filter trains.

The applicant stated that no potential sources of toxic gas releases were identified off-site. The NRC staff previously found that the applicant's evaluation of protection of control room operators against potential toxic gas release accidents was adequate. Self-contained-type breathing apparatuses are available to operator personnel. The ONS Units 1 and 2 control room has six apparatuses with 12 refill bottles and the ONS Unit 3 control room has three apparatuses with 6 refill bottles.

A purge fan in the wall of the Unit 2 equipment room purges air to the auxiliary building corridor where it can be transported by the auxiliary building HVAC equipment, monitored, and exhausted through the unit vent. The Units 1 and 2 control room is purged with portable equipment. In Unit 3, two purge and exhaust ducts are furnished for the equipment room and kitchen area of the control room. These exhaust ducts enable the equipment room, cable room, and control room to be purged in the event of a fire. The fan for purging Unit 3, which is designed to remove smoke from the control room through the kitchen and from the equipment room, is located on elevation 838'-0" with HVAC equipment and would exhaust to the area that would enable the auxiliary building system to pick up, monitor, and discharge products of combustion through the plant vent. Neither a single failure nor an inadvertent operation of the purge systems would affect plant operations. A single failure would require that portable equipment be used to purge individual areas. The control room is isolated from other areas of the plant by 3-hour fire barriers, except for the wall adjacent to the lobby around the entrance door, where a steel plate was installed to satisfy the concerns other than fire protection. Ionization smoke detection is provided in the control room and cable rooms.

In a letter dated October 15, 1999, the applicant stated that certain mechanical components associated with portions of the CRPFS have been added to the scope of license renewal due to the addition of the Chilled Water (WC) System in response to Open Item 2.2.3.4.3.2.1-1. The components were identified in Attachment 2, Table 3, to the letter. No new components types were identified as a result of this effort. The WC System is discussed in Section 2.2.3.4.10 of this report. The applicant identified maintaining a suitable environment (within acceptable limits) in the control room after postulated design-basis events as the intended function for the portions of the CRPFS that have been added to the scope of license renewal. In response to Open Item 2.2.3.4.3.2.1-2, the applicant stated that it will manage the effects of aging of the CRPFS sealant materials as part of its control room ventilation system examination required by the ONS Technical Specifications Surveillance Requirement 3.7.9.1. The staff's evaluation of the AMR for sealant materials is discussed in Section 3.6.1 of this report.

In Section 2.5.8 of Exhibit A of the LRA and the UFSAR, the applicant identified the following intended functions for the CRPFS based on 10 CFR 54.4(a)(1) and (2):

<u>Section 2.5.8 of Exhibit A of the LRA</u> -

- To maintain the control room at a positive pressure using filtered outside air during emergency operation to prevent in-leakage of radioactive effluent or toxic gases from the turbine building, auxiliary building, or outside atmosphere; and

- To maintain a suitable environment in the control room and associated areas for equipment operability and personnel habitability.

<u>Sections 6.4 and 9.4 of the UFSAR</u> -

- To provide HVAC to the control room, cable rooms, and electrical equipment rooms to ensure habitability within acceptable limits for the operation of unit controls as necessary for equipment and operating personnel;

- To provide toxic protection to control room operators against the on-site release from potential toxic gas accidents.

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

<u>Section 2.5.8 of Exhibit A of the LRA</u> -

- To remove smoke from the control room during and after a fire.

<u>Section 9.4 of the UFSAR</u> -

- Control area temperatures of control room, cable room, and electrical room related to station blackout, within limits as specified in the license commitment 16.8.1.

Penetration Room Ventilation System (PRVS)

The PRVS has two fans and two filter assemblies. Both fans discharge through a single line to the unit vent. The fans and filter trains for the system are redundant and only one fan and one filter train is required for emergency operation. During normal operation, this system is held on standby and each fan is aligned with a filter assembly. The engineered safeguards signal from the reactor building pressure will actuate the fans. The control room, as well as remote instrumentation, monitors operation.

The three valves in each purge-line penetration will be closed by a reactor building isolation signal. The reactor building purge equipment, if running, will be shut down from an interlock on the reactor building purge isolation valves. After the external valves close, a small, normally open valve vents any leakage from the two outermost valves into the penetration room. The reactor building purge equipment is not activated when the reactor is above cold-shutdown conditions.

Following a loss-of-coolant accident, a reactor building isolation signal will place the system in operation by starting both full-size fans. Two power-operated butterfly valves, which open when the fans start, are installed downstream of each fan. These valves will be closed to prevent recirculation if one fan fails. A check valve is also installed downstream of each fan to prevent recirculation if a fan fails. In the event of a fan failure, the normally closed tie valve can be opened from its remote manual station to maintain adequate cooling air through the idle filter train.

The system utilizes remote manual control valves in conjunction with constant-speed fans to provide the proper negative pressure in the penetration room. If the leakage increases during operation, causing a decrease in negative pressure below 0.06 inches water gauge with respect to the outside atmosphere, the remote manual control valve will be adjusted or leaks will be repaired to bring the negative pressure to 0.06 inches water gauge or more.

The remote manual control valve is also used to compensate for filter loading. Initially, it will be partially closed; and as the filter loads up causing a decrease in flow and negative penetration room pressure, the valve will gradually be opened so that the pressure drop across the filter-valve combination remains constant. By periodically adjusting the remote manual control valve to offset the effect of increased leakage and filter loading, the system characteristic remains constant.

The communicative paths between various parts of the penetration room are very large in comparison with the minute leakage that might exist because of imperfect seals. Therefore, it can be assumed that no pressure differentials exist in the room so that an instrument string sensing pressure at a single point can be used. Penetration room pressure is displayed in the control room and excessive and insufficient vacuums are annunciated. During normal operation, an operator can actuate the system to test it. Particulate filtration is achieved by a medium efficiency pre-filter and a HEPA filter. Adsorption filtration is accomplished by an activated charcoal filter. The filter consists of three horizontal, removable-type, double-tray, carbon cells. Flow through the trays is essentially vertical. At rated flow, the average face velocity is 40 ft/min and the residence time is 0.25 seconds. Each tray contains 40 lb. of carbon. The carbon is impregnated so that it will adsorb methyl iodide as well as elemental iodine. In Section 2.5.8 of Exhibit A of the LRA and Section 9.4 of the UFSAR, the applicant identified the following intended functions for the PRVS based on 10 CFR 54.4(a)(1) and (2):

Section 2.5.8 of Exhibit A of the LRA -

- To control and minimize the release of radioactive materials from the reactor building to the environment during post-accident conditions;
-
- To collect and process potential post-accident conditions reactor building penetration leakage to minimize environmental radiation levels; and
- To maintain a negative pressure in the penetration room with respect to the surrounding areas (outside atmosphere and auxiliary building) during normal operation to prevent uncontrolled releases.

Section 9.4 of the UFSAR -

On the basis of the intended functions identified above for the ABVS, CRPFS, and PRVS, the portions of these systems that were identified by the applicant as within the scope of license renewal include all safety-related components in the system (electrical, mechanical, and instrument). The applicant described their process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit of the LRA. Based on this methodology, the applicant identified the portions of the ABVS, CRPFS and PRVS that are within the scope of license renewal on flow diagrams listed in Table 2.5-12 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2. of Exhibit A 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 2.5-13 of Exhibit A of the LRA.

Auxiliary Building Ventilation System (ABVS) - The following five device types are identified as within the scope of license renewal and subject to an AMR: air flow monitors (aluminum, carbon steel, and galvanized steel), AHUs (aluminum, stainless steel, and galvanized steel), ductwork (aluminum, stainless steel, and galvanized steel), filters (aluminum, stainless steel, and galvanized steel), and grills (aluminum, stainless steel, and galvanized steel).

Control Room Pressurization and Filtration System (CRPFS) - The following eight device types are identified as within the scope of license renewal and subject to an AMR: air flow monitors (aluminum, carbon steel, and galvanized steel), AHUs (aluminum, stainless steel, and galvanized steel), ductwork (aluminum, stainless steel, and galvanized steel), filters (aluminum, stainless steel, and galvanized steel), grills (aluminum, stainless steel, and galvanized steel), heaters (aluminum, galvanized steel and stainless steel), tubing (brass, carbon steel, copper, and stainless steel) and sealants.

Penetration Room Ventilation System (PRVS) - The following six device types are identified as within the scope of license renewal and subject to an AMR: filters (carbon steel), grills (aluminum, stainless steel, and galvanized steel), orifices (stainless steel), pipes (carbon steel), tubing (brass, carbon steel, copper, and stainless steel), and valve bodies (carbon steel).

The applicant further indicated in Table 2.5-13 that the ABVS, CRPFS, and PRVS pressure boundary is the only applicable intended function associated with the components of the ABVS, CRPFS, and PRVS that are subject to an AMR.

2.2.3.4.3.2 Staff Evaluation

The staff reviewed Section 2.5.8 of Exhibit A of the LRA to determine whether there is reasonable assurance that the ABVS, CRPFS, and PRVS components within the scope of license renewal (10 CFR 54.4) and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued a request for additional information (RAI), by letter dated November 24, 1998, regarding the ABVS, CRPFS, and PRVS. The applicant responded to the RAI in letters dated January 25, February 8, and February 17, 1999.

2.2.3.4.3.2.1 HVAC Systems Within the scope of License Renewal and Subject to an Aging Management Review

In Section 2.5.2.2, "Identification of Mechanical Components Subject to an Aging Management Review" of Exhibit A of the LRA, the applicant discussed the process of identifying mechanical components subject to an AMR, which is evaluated in Section 2.1 of this SER, "Methodology for Identifying Structures and Components Subject to Aging Management Review." The applicant stated in Section 2.5.8 of the LRA that the flow diagrams listed in Table 2.5-12 show the evaluation boundaries for the (highlighted) portions of the HVACS that are within the scope of license renewal and Table 2.5-13 lists those mechanical components and their intended functions.

The staff reviewed portions of the UFSAR, including Sections 6.4 and 9.4, to determine if there were any portions of the system that the applicant did not identify as within the scope of license renewal that should have been so identified. The staff also reviewed Sections 6.4 and 9.4 of the UFSAR to determine if there were any safety-related system functions that were not identified as intended functions in the LRA, and to determine if there were SCs having intended functions that might have been omitted from consideration within the scope of the license renewal. The staff also reviewed the system flow diagrams of OLRP-1002 to determine if any structures or components not identified in the LRA as within the scope of the rule should have been so identified under 10 CFR 54.4(a)(2) or (3). The staff compared the functions described in the UFSAR to 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 HVACs in Table 2.5-13 of Exhibit A of the LRA using the screening methodology described in section 2.5.2 of Exhibit A of the LRA. The staff evaluated the scoping and screening methodology and documented its findings in Section 2.1 of this SER. As described in more detail in the following subsections, the staff sampled from the list of SCs for each auxiliary system identified by the applicant as subject to an AMR to get reasonable assurance that all components subject to an AMR were appropriately identified. The staff also sampled the 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 a configuration change or were subject to replacement on the basis of a qualified life or specified time period (i.e, active or short-lived). As discussed below, the staff found no omissions and, therefore, concluded that there was reasonable assurance that the applicant adequately identified those portions of the ABVS, CRPFS, and PRVS and the associated components that fall within the scope of license renewal and subject to an AMR in accordance with 10 CFR Part 54.4 and 54.21.

To help ensure that those portions of the ABVS, CRPFS, and PRVS identified as not within the scope of license renewal did not perform any intended functions, the staff issued an RAI based on the information in the UFSAR and the LRA. The staff noted that Section 2.5.8 of Exhibit A of the LRA presents a summary description of the system functions, highlighted boundaries in flow diagrams of OLRP-1002, "License Renewal Flow Diagrams, Oconee Nuclear Station, Units 1, 2, and 3," and tabulates components within the scope of license renewal for the ABVS, CRPFS, and PRVS subject to an AMR. The corresponding drawings for these systems in the UFSAR, however, show additional components that were not listed in Table 2.5-13 of Exhibit A of the LRA. The staff's RAI and the applicant's response are discussed below:

Auxiliary Building Ventilation System

The staff requested clarifications or justifications or both in RAI 2.5.8-1 concerning the exclusion from the scope of license renewal or an AMR or both of (1) the damper, damper operator, gravity damper, bird screen, exhaust/supply fans and enclosures, heating/cooling coils, compressors, valves, and air dryers; (2) exhaust filtration function for the ABVS served areas for the hot machine shop and spent fuel pool areas; and (3) several supply or return/exhaust from the various components or both, including exhaust fan, condenser steam air ejectors, and sample hood, as shown in flow diagram OLRP-1002 for the ABVS.

In a letter dated February 8, 1999, the applicant responded to RAI 2.5.8-1 and stated that the dampers, damper operators, gravity dampers, fans, compressors, and air dryers are excluded from an AMR in accordance with 10 CFR 54.21(a), and that fan enclosures (identified as "air handling unit") and bird screens (identified as "grills") are subject to an AMR as identified in

Table 2.5-13 of Exhibit A of the LRA. From a pressure boundary standpoint, the cooling and heating coils are considered as subcomponents of the AHUs that are subject to an AMR, and AHUs are listed in Table 2.5-13 of Exhibit A of the LRA. Pursuant to10 CFR 54.4, the compressors, valves, and air dryers are not components of the ABVS and are not necessary for the ABVS to perform its intended function, therefore, they are excluded from the license renewal scope. The applicant further clarified in a letter dated May 10, 1999, in response to RAI 2.5.8-1, that the ABVS is constructed of ductwork and dampers, not pipes and valves. The ductwork is subject to an AMR and is listed in Table 2.5-13 of Exhibit A of the LRA. The dampers are within the scope of license renewal, but are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i). On the basis of the additional information provided by the applicant, the staff finds the exclusion of valve bodies and piping from the scope of ABVS components requiring an AMRs, acceptable.

In a letter dated February 8, 1999, the applicant responded to RAI 2.5.8-2 concerning the exclusion of the hot machine shop exhaust from the scope of license renewal. The applicant stated that the license renewal scoping criterion of §54.4 does not contain any requirement related to 10 CFR Part 20 and, therefore, it did not use 10 CFR Part 20 as a criterion to determine which systems were within the scope of license renewal. Additionally, no design-basis events occur in the hot machine shop areas and no portions of the ABVS supporting the hot machine shop are relied upon to perform the smoke removal function and, therefore, hot machine shop areas are not within the scope of license renewal. The staff agrees with the applicant's rationale for excluding the hot machine shop exhaust from the scope of license renewal. In its response concerning the exclusion of the spent fuel pool areas exhaust from the scope of license renewal, the applicant stated that (1) the environment in the spent fuel pool area is controlled by the SFP ventilation system, (2) exhaust from the spent fuel pool areas is not filtered before release to the plant vents, (3) the exhaust from the spent fuel pool areas is filtered by the reactor building purge system filter package before release to the plant vents as required by ONS Technical Specifications, and (4) a review of fuel handling design-basis events determined that no system or component functions are credited in support of accident mitigation. The NRC staff has previously concluded in Section 11.0 of the "Safety Evaluation by the Directorate of Licensing, U.S. Atomic Energy Commission, in the matter of Duke Power Company, Oconee Nuclear Station, Units 2 and 3," dated July 6, 1973, that the offsite dose for a fuel handling accident is less than the guideline values of 10 CFR Part 100 for Oconee Nuclear Station, Units 2 and 3. On this basis, the staff agrees with the applicant's assessment that even though the exhaust air filtration from the spent fuel pool areas conforms with 10 CFR Part 100 guidelines, it is not credited in support of accident mitigation (fuel handling accident) and, therefore, SFP exhaust is outside the scope of license renewal.

In a letter dated January 25, 1999, the applicant responded to RAI 2.5.8-3. The applicant stated that (1) the highlighted portions of the supply or return/exhaust ductwork or both, shown on flow diagrams OLRFD-116G-1.1, OLRFD-116G-1.2, OLRFD-116G-2.1, OLRFD-116G-3.1, and OLRFD-116G-3.2, are required for fire protection as they support a system-intended function of smoke removal for the auxiliary building and non-highlighted portions do not support any ABVS-intended function as defined in §54.4(a); (2) OLRFD-116G-1.3 will be revised to correct editorial comment for "LR" scoping arrows; and (3) the exhaust from the condenser steam air ejectors and the sample hood to the specific vent stack of Units 1, 2, and 3 and the filter discharges to specific vent stacks of Units 1 and 3 shown on OLRFD-116G-1.4 do not support any ABVS-intended function as defined in §54.4(a)(1), (2), (3), or (b). The staff agrees with the applicant's approach for excluding the non-highlighted portions of the ABVS, which do not support the intended functions as defined in §54.4(a)(1), (2), (3), or (b).

Control Room Pressurization and Filtration System

The staff requested clarifications or justifications or both concerning the exclusion from the scope of license renewal or an AMR or both of (1) the dampers, damper operators, gravity dampers, bird screens, exhaust/supply fans and enclosures, heating/cooling coils, compressors, valves, and air dryers and (2) sealant materials to control the unfiltered in-leakage for the pressurization function of CRPFS.

In a letter dated February 8, 1999, the applicant responded to RAI 2.5.8-1. In its response, the applicant stated that the dampers, gravity dampers, and fans are excluded from an AMR in accordance with 10 CFR 54.21(a)(1)(i), while heating coils, fan enclosures (identified as "air handling units"), and bird screens (identified as "grills") are subject to an AMR as identified in Table 2.5-13 of Exhibit A of the LRA. The staff finds the applicant's rationale for listing these components in Table 2.5-13 of Exhibit A of the LRA as subject to an AMR acceptable. From a pressure boundary standpoint, the cooling and heating coils are considered as subcomponents of the AHUs that are subject to an AMR, and AHUs are listed in Table 2.5-13 of Exhibit A of the LRA. Pursuant to 10 CFR 54.4, the compressors, valves, and air dryers are not components of the CRPFS and are not necessary for the CRPFS to perform its intended function, therefore, they are excluded from the license renewal scope. The applicant further clarified in a letter dated May 10, 1999, in response to RAI 2.5.8-1, that the CRPFS is constructed of ductwork and dampers, but not pipes and valves. The ductwork is subject to an AMR and is listed in Table 2.5-13 of Exhibit A of the LRA. The dampers are within the scope of license renewal, but are not subject to an AMR in accordance with 10 CFR 54.21(a)(1)(i).

Also in the May 10,1999, letter, the applicant provided reasons why the chilled water (WC) System (which supports the cooling function for the CRPFS) is not included within the scope of license renewal. The applicant stated that for certain design-basis events, the CRPFS maintains a positive pressure in the control room and that air conditioning is not required. The applicant stated that failure of the WC System does not prevent the CRFPS from maintaining a positive pressure in the control room for accident conditions and is not classified ONS Piping Class D for seismic II/I concerns. Further, the applicant stated that the CRFPS is credited with maintaining a suitable environment in the control room during a fire event and providing for smoke removal from the control room, neither of which require air conditioning supported by the WC System. The applicant also noted that the CRPFS and the supporting WC System do not perform an intended function in support of any other regulated event listed in 10 CFR 54.4(a)(3).

The applicant concluded from this evaluation that the WC System is not within the scope of license renewal. The staff did not agree with this conclusion. It appeared to the staff that the WC System was needed at ONS in order to assure the capability to shutdown the reactor and maintain it in a shutdown condition. The staff requested that the applicant identify where in the CLB the loss of the WC System has been addressed, and clarify why the WC System is not within the scope of license renewal and subject to an AMR. This was Open Item 2.2.3.4.3.2.1-1.

The applicant reviewed the open item and by letter dated October 15, 1999, the applicant stated that the WC System is within the scope of license renewal and is subject to an AMR. The applicant also stated that a new TS for the WC System has been added to the ONS CLB under Section 3.7.16, "Control Room Area Cooling Systems (CRACS)."

On the basis of the above review, that includes the WC System as being within the scope of LR and subject to an AMR, Open Item 2.2.3.4.3.2.1-1 is closed. The staff's evaluation of the SCs of the WC System that are within the scope of license renewal and subject to an AMR is addressed in Section 2.2.3.4.10 of this report.

In a letter dated February 17, 1999, the applicant responded to RAI 2.5.8-4 concerning the use of sealant materials in CRPFS. In its response the applicant stated the following:

> The condition of these sealant materials is determined during the *Control Room Pressure Test* conducted in accordance with technical specifications (Oconee Improved Technical Specification ITS 3.7.9, Surveillance Requirement SR 3.7.9.3). The test acceptance criterion requires prompt action to correct the leaking seal by either repair or replacement. In addition, the requirement to maintain a positive pressure within the control room area is a function that is maintained under the Maintenance Rule (§50.65) program. For the sealant materials, the programmatic action is not to "manage" sealant life, but rather to replace the sealant when its condition indicates it is no longer acceptable for service. Therefore, sealant materials used to control unfiltered in-leakage are repaired or replaced based upon performance or condition and, thus, are not subject to an AMR.

The staff notes that the SOC for 10 CFR Part 54 (60 FR 22478) states the following:

> . . . the Commission has decided not to generically exclude passive structures and components that are replaced based on performance or condition monitoring from an AMR. . . . However, the Commission does not intend to preclude a license renewal applicant from providing site-specific justification in a license renewal application that a replacement program on the basis of performance or condition for a passive structure or component provides reasonable assurance that the intended function of the passive structure or component will be maintained . . .

Accordingly, the staff concluded that the condition monitoring provided by the referenced ONS ITS surveillance did not, by itself, provide a plant-specific basis for excluding the sealant materials in the CRPFS from an AMR. However, the staff believes that the ITS surveillance, in conjunction with related system inspections and the corrective action process, can provide an adequate aging management program for the sealant materials in the CRPFS System. This was Open Item 2.2.3.4.3.2.1-2.

The applicant reviewed the open item and by letter dated October 15, 1999, stated that the aging of the CRPFS sealant materials will be managed by the control room ventilation system examination using the program attributes discussed in LRA Section 4.2 of Exhibit A, that is required by ONS Technical Specification (TS) Surveillance Requirement (SR) 3.7.9.1. The applicant further stated that the examinations that serve to manage the aging of the sealants, rubber boots, seals, and flexible collars of the CRPFS include the following attributes: purpose, scope, aging effects, method, sample size, industry codes and standards, frequency, acceptance criteria, corrective action, timing of new program initiation, administrative controls, and regulatory basis. The applicant also stated that the sealants (caulking, sealants, and water stops) associated with the control room pressure boundary which includes the walls, ceiling, floor, access doors, and penetrations for electrical and mechanical equipment are addressed in response to Open Item 2.2.3.6.1.2.1-1 in the October 15, 1999 letter. The aging of the control room pressure boundary fire barriers (access doors and penetrations) is managed by the fire protection program which is discussed in LRA Section 4.19 of Exhibit A.

As stated in the letter dated October 15, 1999, in response to SER Open Item 2.2.3.4.3.2.1-2, the CRPFS sealant materials will be managed by the control room ventilation system examination which is required by ONS Technical Specification Surveillance Requirement 3.7.9.1. The staff's evaluation of the AMR for sealants can be found in Section 3.6.1 of this report. The staff agrees with the applicant that the CRPFS sealant material is within the scope of LR and subject to AMR. Therefore, Open Item 2.2.3.4.3.2.1-2 is closed.

Penetration Room Ventilation System

The staff requested clarifications or justifications or both concerning the exclusion from the scope of license renewal or an AMR or both of (1) the dampers, damper operators, gravity dampers, bird screens, exhaust/supply fans and enclosures, heating/cooling coils, compressors, valves, and air dryers. In a letter dated February 8, 1999, the applicant responded to RAI 2.5.8-1. The applicant stated that the dampers, gravity dampers, and fans are excluded from an AMR in accordance with 10 CFR 54.21(a). The valve bodies and pipes are subject to an AMR, as identified in Table 2.5-13 of Exhibit A of the LRA. The staff finds the applicant's rationale acceptable concerning the valve bodies and pipes for listing them in Table 2.5-13 of Exhibit A of the LRA as subject to an AMR. Since PRVS is primarily an exhaust filtration system, the bird screens, heating coils, cooling coils, compressors, fan enclosures, and air dryers are not components of the PRVS and, therefore, are not within the scope of license renewal.

Some components that are common to many systems, including ABVS, CRPFS, and PRVS, have been included in separate sections of Exhibit A to the LRA which address those components for the entire plant. As indicated below, the following components were not included in the individual system sections:

- The staff evaluated component supports for piping, cables, and equipment, which are discussed in Section 2.7 "Structures and Structural Components" of Exhibit A of the LRA in Section 2.2.3.6 of the SER.

- The staff evaluated electrical components that support the operation of the HVACS — which are discussed in Section 2.6 "Electrical Components" of Exhibit A of the LRA — in Section 2.2.3.7 of the SER.

- Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, rules for the identification of components within the scope of license renewal in OLRP-1002 specifically state that instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow. The applicant evaluated instrument line components with the system to which they are attached. The instrumentation lines for the CRPFS and PRVS are listed in Table 2.5-13 of the LRA as "tubing." The "tubing" category of instrumentation lines for the ABVS is evaluated in Section 2.2.3 of this SER.

Based on a review of Exhibit A of the LRA, supporting information in the UFSAR, and the applicant's responses to the staff's RAI, the staff has reasonable assurance that all portions of the HVAC systems (ABVS, CRPFS, and PRVS) with intended functions meeting the criteria in 10 CFR 54.4 are identified as being within the scope of license renewal on the flow diagrams listed in Table 2.5-8 of Exhibit A.

Using the information provided on the flow diagrams for the HVAC system (ABVS, CRPFS, and PRVS) (Table 2.5-13 of Exhibit A), the staff sampled several components to determine whether the applicant properly identified the passive, long-lived components in the list of components as subject to an AMR (Table 2.5-13 of Exhibit A) from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams were included in the list of components that are subject to an AMR for the HVAC systems (ABVS, CRPFS, and PRVS) in Table 2.5-13. No omissions were identified. Based on this review the staff has reasonable assurance that the applicant has identified the components of HVAC systems (ABVS, CRPFS, and PRVS) subject to an AMR.

2.2.3.4.3.2.2 Review Findings for HVAC

The staff has reviewed the information in Section 2.5.8, "Air Conditioning, Heating, Cooling and Ventilation Systems," of Exhibit A of the LRA. On the basis of this review, the staff has reasonable assurance that the applicant has identified and listed the portions of the ABVS, CRPFS, and PRVS, and the associated components thereof, that are 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.

2.2.3.4.4 Post-Accident Hydrogen Control

In Section 2.5.10, "Post-Accident Hydrogen Control," of Exhibit A of the LRA, the applicant identified the systems and components that are within the scope of license renewal and which of those within-scope components are subject to an AMR. The Post-Accident Hydrogen Control Systems include the containment hydrogen control system and the Post-Accident Monitoring System.

Component (equipment and piping) supports for the system are presented separately in Section 2.7of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant included instrument line components with the system to which they are attached.

2.2.3.4.4.1 Summary of Technical Information in the Application

Containment Hydrogen Control System (CHCS)

The CHCS maintains the reactor building hydrogen concentration below flammable limits following a LOCA. During normal operation, the CHCS piping is used as a flowpath for radiation monitoring and atmosphere sampling of the reactor building. The CHCS also includes a portable hydrogen recombiner that is shared among all three units. Hydrogen concentration is controlled by circulating containment atmosphere through the hydrogen recombiner. This system also contains containment isolation valves.

The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. The applicant identified the portions of the CHCS that are within the scope of license renewal on flow diagrams listed on Table 2.5-16 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2 of Exhibit A 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 that list on Table 2.5-17 of Exhibit A of the LRA. Four component types were identified as subject to an AMR: flex hose, pipe, hydrogen recombiner, and valve bodies. For these component types, maintaining the pressure boundary was identified as the intended function.

Post-Accident Monitoring System (PAMS)

The PAMS is designed to draw air samples from various locations inside containment following an accident to determine the concentration of hydrogen.

The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.5.2 of Exhibit A of the LRA. The applicant identified the portions of the PAMS that are within the scope of license renewal on flow diagrams listed on Table 2.5-16 of Exhibit A of the LRA. Using the methodology described in Section 2.5.2.2 of Exhibit A of the LRA, the applicant compiled a list of the mechanical components and component types that are within the license renewal boundaries and are subject to an AMR and identified their intended functions. The applicant provided that list on Table 2.5-17 of Exhibit A of the LRA. Three component types were identified as subject to an AMR: pipe, tubing, and valve bodies. For these component types, maintaining the pressure boundary was identified as the intended function.

2.2.3.4.4.2 Staff Evaluation

The staff reviewed Section 2.5.10, "Post-Accident Hydrogen Control," of Exhibit A of the LRA to determine whether there is reasonable assurance that the applicant has identified the post-accident hydrogen control systems and components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.4.2.1 Post-Accident Hydrogen Control Systems Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed Section 15.16, "Post-Accident Hydrogen Control," of the UFSAR and compared the description of the systems and other components in the UFSAR to the description in the application to determine whether the applicant should have identified any additional portions of the system as within the scope of license renewal. As described in Sections 2.5.10 of Exhibit A of the LRA, essentially all portions of the post-accident hydrogen control systems were determined to be within the scope of license renewal and subject to an AMR. The hydrogen analyzers are within the scope of license renewal but perform their intended function with a change in properties, and pursuant to 10 CFR 54.21(a)(1)(i), are not subject to an AMR. The staff reviewed the remaining components of the post-accident hydrogen control systems to verify that they do not perform any intended functions. The staff also reviewed Section 15.16 of the UFSAR to determine whether the applicant had failed to identify any additional functions that were not identified as intended functions in the LRA. The staff found no omissions by the applicant. Therefore, there is reasonable assurance that the applicant adequately identified all portions of the post-accident hydrogen control systems that fall within the scope of license renewal and are subject to an AMR in accordance with 10 CFR Part 54.

2.2.3.4.4.2.2 Review Findings for Post-Accident Hydrogen Control

The staff has reviewed the information provided in Section 2.5.10 of Exhibit A of the LRA and the additional information provided by the applicant in response to the staff's RAIs. Based on this review, the staff has reasonable assurance that the applicant has appropriately identified those portions of the post-accident hydrogen control systems, and components thereof, that are within the scope of license renewal and subject to an AMR in accordance with the requirements of 10 CFR 54.4.

2.2.3.4.5 Reactor Coolant Pump Motor Oil Collection System

In Section 2.5.11, "Reactor Coolant Pump Motor Oil Collection System," of the LRA, the applicant described the components that utilize or process lubricating oil for the reactor coolant pumps (RCPs), including the oil lift system, oil coolers, and the upper and lower pots. The applicant identified that the RCP motor oil collection system is within the scope of license renewal and also identified the components that are subject to an AMR. By letter dated February 8, 1999, the applicant responded to requests for additional information (RAIs) regarding the fire protection (FP) systems and components. On April 1, 1999, the staff participated in a telephone conference with the applicant to discuss questions that the staff had regarding fire protection. A summary of that discussion is documented in a phone call summary dated April 13, 1999.

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.5.1 Summary of Technical Information in the Application

Structures and mechanical systems that 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. In 10 CFR 54.4(a)(3), the Commission requires that all SSCs 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. The applicant's FP program meets the requirements of 10 CFR 50.48 by complying with Appendix A to Branch Technical Position (Auxiliary Power Conversion System Branch) 9.5-1 (BTP APCSB) 9.5-1, "Guidelines for Fire Protection for Nuclear Plants Docketed Prior to July 1, 1976," and Sections III.G, III.J, and III.O of Appendix R, "Fire

Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979," to 10 CFR Part 50. The RCP motor oil collection system is relied upon to meet the requirements of Appendix R, Section III.O, "Oil Collection System for Reactor Coolant Pump."

In 10 CFR 50.48, the Commission requires that the applicant implement and maintain an FP program. The FP program is incorporated into various plant documents to ensure that it remains updated. Furthermore, flow diagrams are updated any time plant or licensing changes warrant a revision. As described in the LRA, the applicant used flow diagrams to indicate the evaluation boundaries for mechanical systems that were within the scope of license renewal. Mechanical components are considered to be those installed in components that contain a fluid, including air or gas. In a two-step process, the applicant identified the mechanical components subject to an AMR. First the applicant reviewed the flow diagrams and developed a menu of mechanical component types at ONS. Secondly, the applicant identified mechanical components and component types within the evaluation boundaries that are subject to an AMR, along with their intended functions. In Section 2.5.11 of the LRA, the applicant described the components of the RCP motor oil collection system that are subject to an AMR and listed their intended functions.

Each RCP has several components that utilize or process lubricating oil, including the oil lift system, oil coolers, and the upper and lower pots. Each RCP is equipped with an oil collection system in accordance with the requirements of Appendix R, Section III.O. The underlying purpose of the lube oil collection system is to ensure that leaking oil will not lead to a fire that could damage safety-related equipment during normal conditions or design-basis accident conditions.

The portions of the system piping that are within the scope of license renewal are designed and constructed to the requirements of Oconee System Piping Class D. These portions are designed to remain intact following a design-basis earthquake. License renewal flow diagrams OLRFD-100A-1.4, OLRFD-100A-2.4, and OLRFD-100A-3.4 show the evaluation boundaries for the portion of the RCP motor oil collection system that is within the scope of license renewal. In Table 2.5-19 of the LRA, the applicant identified mechanical components of the RCP motor oil collection system that are subject to an AMR and also identified their intended functions.

2.2.3.4.5.2 Staff Evaluation

In 10 CFR 54.21(a)(1), the Commission's regulations state that for those SSCs within the scope of 10 CFR 54.4, the integrated plant assessment (IPA) must identify and list those SCs subject to an AMR. The staff reviewed Section 2.5.11 of the LRA, as supplemented by a letter dated February 8, 1999, and the other documentation discussed below, to determine whether there was reasonable assurance that the applicant has appropriately identified the components and supporting systems that serve FP-intended functions, and are within the scope of license renewal in accordance with 10 CFR 54.4, and are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.5.2.1 Reactor Coolant Pump Motor Oil Collection System Within the Scope of License Renewal and Subject to an Aging Management Review

This evaluation determines whether the applicant has properly identified, for the RCP motor oil collection system, the components that are within the scope of license renewal. The staff will then determine if the components that are within the scope of license renewal were properly identified by the applicant as being subject to an AMR.

The applicant searched its licensing documents for commitments made to comply with 10 CFR 50.48 and stated that any structures or components that are relied upon for meeting the commitments are included within the scope of license renewal. The applicant also reviewed flow diagrams, design-basis documents and drawings to identify portions of the RCP motor oil collection system within the scope of license renewal.

The staff sampled portions of the FP safety evaluations (SEs) dated August 11, 1978, April 28, 1983, and August 21, 1989, and UFSAR Section 9.5, "Other Auxiliary Systems." The staff then compared the RCP motor oil collection components identified within the SEs to the RCP motor oil collection flow diagrams OLRFD-100A-1.4, OLRFD-100A-2.4, and OLRFD-100A-3.4 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. As part of the evaluation, the staff also reviewed the same flow diagrams for the RCP motor oil collection 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. The staff determined that all components and equipment that the applicant identified for the RCP motor oil collection system are within the scope of license renewal. In addition, these components are passive and long-lived and are, therefore, subject to an AMR. These components are enclosures, flex hoses, pipes, tubing, and valve bodies.

Flow diagram OLRFD-100A-1.4 for the RCP motor oil collection system, identifies portions of piping connected to the RCP motor oil collection tank that were not included within the highlighted evaluation boundaries. As documented in a phone call summary dated April 13, 1999, the staff asked the applicant if it omitted these portions of piping from the scope of license renewal because of their maintenance functions. The applicant stated that these piping lines were only used to drain oil during maintenance and, therefore, are not required under Appendix R, Section III.O. The staff agrees and, therefore, is reasonably assured that the applicant did not exclude system piping or components with intended functions from the scope of license renewal.

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the portions of the system piping and the components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

After the staff determined which components were within the scope of license renewal, it 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, and to determine 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 from flow diagrams OLRFD-100A-1.4, OLRFD-100A-2.4, and OLRFD-100A-3.4, and compared them to the list of components with intended functions that the applicant presented in Table 2.5-19, to verify that there were no omissions of passive, long-lived components that were subject to an AMR. The staff did not find any omissions of long-lived, passive components with intended functions. Table 1, below, categorizes the types of mechanical components for the RCP motor oil collection system that have passive, long-lived components that are subject to an AMR.

Table 1 Components of the RCP Motor Oil Collection System and Their Intended Functions

Mechanical Component	Intended Function (s)
Enclosures (Carbon Steel)	Pressure Boundary
Flex Hose (Carbon Steel)	Pressure Boundary
Pipe (Carbon Steel)	Pressure Boundary
Tubing (Brass, Carbon Steel, Copper, Stainless Steel)	Pressure Boundary
Valve Bodies (Carbon Steel, Stainless Steel)	Pressure Boundary

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the components for the RCP motor oil collection system that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.6 Reactor Coolant System Vents, Drains, and Instrument Lines

In Section 2.5.12, "Reactor Coolant System Vents, Drains, and Instrument Lines," of the LRA, Duke (the applicant) described the SCs of the reactor coolant system (RCS) vents, drains, and instrument lines that are subject to an AMR for license renewal.

Component (equipment and piping) supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.6.1 Summary of Technical Information in the Application

As described in the LRA, the RCS vents, drains, and instrument lines, as well as the Duke Inservice Inspection Class A piping are discussed in Section 2.4 of the application. With the exception of the pressurizer relief valve piping, all piping that is not Duke Inservice Inspection Class A in the RCS is 2-inch nominal pipe diameter or smaller.

The portions of the RCS, other than the Duke Inservice Inspection Class A piping, within the scope of license renewal are Oconee System Piping Class B or C. These piping classes are seismically designed to withstand a design-basis earthquake without a loss of function. This system is constructed of stainless steel. The internal environment of the portions of the RCS applicable to license renewal is borated water. The RCS external surfaces are exposed to the reactor building and auxiliary building environments.

The following components of the RCS vents, drains, and instrument lines are within the scope of license renewal, and are subject to an AMR: mechanical expansion joint, pipe, pressure breakdown coil, tubing, and valve bodies. The intended function for these components, based on the requirements of 10 CFR 54.4(a), is listed as pressure boundary.

2.2.3.4.6.2 Staff Evaluation

The staff reviewed this section of the application to determine whether there is reasonable assurance that the RCS vents, drains, and instrument line components and supporting structures subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.21(a)(1). This was accomplished as described below.

2.2.3.4.6.2.1 RCS Vents, Drains, and Instrument Lines Within the Scope of License Renewal and Subject to an AMR

As part of the evaluation, the staff determined whether the applicant had properly identified the SSCs 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 UFSAR for the RCS vents, drains, and instrument lines, and compared the information in the UFSAR with the information in the application to identify portions that the applicant did not identify as within the scope of license renewal and subject to an AMR. The staff then reviewed SCs outside the applicant-identified portion to verify that (1) they do not have any intended functions as delineated in 10 CFR 54.4(a) and, if they did, to verify that (2) they are either active components or 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 UFSAR for any safety-related system functions that were not identified as intended functions in the application to verify that all SCs having intended functions were not omitted from consideration within the scope of the rule.

2.2.3.4.6.2.2 Review Findings for RCS Vents, Drains, and Instrument Lines

On the basis of the staff's review of the information contained in Section 2.5.12 of the application, and the supporting information in the ONS UFSAR, as discussed in the preceding section, 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 RCS vents, drains, instrument lines and associated components that fall within the scope of license renewal and are subject to an AMR, in accordance with 10 CFR 54.4(a) and 10 CFR 54.21(a)(1).

2.2.3.4.7 Keowee Hydroelectric Station

In Section 1.2.2, "License Renewal Technical Information," of Exhibit A of the LRA, the applicant described Keowee Hydroelectric Station, which is the on-site emergency power source for ONS. The station consists of two hydroelectric units, which provide two separate and independent power paths.

Component supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.7.1 Summary of Technical Information in the Application

In Section 2.5.13 of the LRA, the applicant identified the following nine systems of the Keowee and their components that are within the scope of license renewal:

- carbon dioxide system
- depressing air system
- generator high-pressure oil system
- governor air system
- governor oil system

- service water system
- turbine generator cooling water system
- turbine guide bearing oil system
- turbine sump pump system

In Table 2.5-22 of the LRA, the applicant identified flow diagrams for these nine systems, and highlighted the evaluation boundaries for these portions of the Keowee Systems that are within the scope of license renewal. The applicant used the screening process described in Section 2.5.2 of the LRA to determine which components are subject to an AMR, and listed those components and their intended functions in Table 2.5-23 of the LRA.

The carbon dioxide system provides fire protection to the Keowee generators. The components of the carbon dioxide system that were identified for license renewal are highlighted in flow diagram KLRFD-108A-1.1. The components subject to an AMR are flexible hose, nozzle, pipe tubing, and valve bodies. The intended function for all these components is maintaining the pressure boundary.

The depressing air system forces water from the turbine space to reduce turbine rolling resistance. The AMR for this system only considers the need for the components in the system to maintain pressure boundary and structural integrity. The components of the depressing air system that were identified for license renewal are highlighted in flow diagram KLRFD-111A-1.1. The components subject to an AMR are pipe and valve bodies. The intended function for all these components is maintaining the pressure boundary.

The generator high-pressure oil system provides two functions. During unit startup and shutdown, system pumps provide a film of oil between the thrust-bearing shoes to keep them apart to reduce wear. When the generator reaches a certain speed, the system pumps stop, and the system provides only pressure boundary for lubrication and cooling of the generator thrust and guide bearings. The components of the generator high-pressure oil system that were identified for license renewal are highlighted in flow diagrams KLRFD-103A-1.1 and 103A-2.1. The components subject to an AMR are filter, pipe, pump casing, tank, tubing, and valve bodies. The intended function for all these components is maintaining the pressure boundary.

The governor air system maintains a cover pressure in the governor oil pressure tank to supply hydraulic oil to operate the turbine wicket gates. The components of the governor air system that were identified for license renewal are highlighted in flow diagrams KLRFD-104A-1.1, 104A-2.1, 105A-1.1, and 105A-2.1. The components subject to an AMR are pipe, tank, and valve bodies. The intended function for all these components is maintaining the pressure boundary.

The governor oil system supplies hydraulic oil to operate the turbine wicket gates. The components of the governor oil system that were identified for license renewal are highlighted in flow diagrams KLRFD-105A-1.1, and 105A-2.1. The components subject to an AMR are pipe, pump casing, tank, tubing, and valve bodies. The intended function for all these components is maintaining the pressure boundary.

The Service Water System supplies cooling water to various plant equipment and supplies water for fire protection services at Keowee. The system is within the scope of license renewal for fire protection. The components of the Service Water System that were identified for license renewal are highlighted in flow diagrams KLRFD-109A-1.1 and OLRFD-117B-1.5. The components subject to an AMR are annubar, filter, fire hydrant, hose rack, mulsifyer, pipe, pump casing, strainer, tubing, and valve bodies. The intended functions for the annubar are maintaining the pressure boundary and throttling, and for all the other components the intended function is maintaining the pressure boundary.

The turbine generator cooling water system supplies cooling water to the turbine packing box, generator thrust bearing coolers, generator air coolers, and turbine guide bearing oil coolers as well as backup cooling to other unit loads. The components of the turbine generator cooling water system that were identified for license renewal are highlighted in flow diagrams KLRFD-100A-1.1 and 100A-2.1. The components subject to an AMR are filter, orifice, pipe, tubing, and valve bodies. The intended functions for the filter are maintaining the pressure boundary and filtering, for the turbine guide bearing oil coolers are maintaining the pressure boundary and heat transfer, and for all the other components, the intended function is maintaining the pressure boundary.

The turbine guide bearing oil system provides lubrication and cooling for the turbine guide bearings. The components of the turbine guide bearing oil system that were identified for license renewal are highlighted in flow diagrams KLRFD-101A-1.1 and 101A-2.1. The components subject to an AMR are orifice, pipe, pump casing, strainer, tank, tubing, turbine guide bearing oil coolers, and valve bodies. The intended functions for the turbine guide bearing oil coolers are maintaining the pressure boundary and heat transfer, and the intended function for all the other components is maintaining the pressure boundary.

The Turbine Sump Pump System is provided with two ac-motor-driven pumps and a dc-motor-driven pump to move water from the turbine wheel pit to the Keowee tailrace. This function is safety-related because flooding in the turbine wheel pit would jeopardize the ability of a Keowee unit to produce emergency power. The components of the Turbine Sump Pump System that were identified for license renewal are highlighted in flow diagrams KLRFD-102A-1.1 and 102A-2.1. The components subject to an AMR are filter, pipe, pump casing, and valve bodies. The intended function for all these components is maintaining the pressure boundary.

2.2.3.4.7.2 Staff Evaluation

The staff reviewed these sections of the LRA to determine whether there is reasonable assurance that the components of the Keowee Hydroelectric Station within the scope of license renewal and subject to an AMR have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). After completing the initial review, the staff issued requests for additional information by letter dated November 20, 1998, regarding the Keowee Hydroelectric Stations. The applicant responded to the RAIs in letters dated January 25 and February 17, 1999.

2.2.3.4.7.2.1 Keowee Hydroelectric Station Within the Scope of License Renewal and Subject to an Aging Management Review

As part of its evaluation, the staff reviewed the LRA and Section 8.3.1.1.1, "Keowee Hydro Station," of the UFSAR, to determine if there were any additional portions of the system and other components that the applicant should have identified in the LRA as within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In Section 2.5.13 of Exhibit A of the LRA, the applicant discussed the Keowee station as if it had only nine subsystems. The staff found that these nine supporting subsystems by themselves were not able to perform the intended function of emergency power generation. Based on the information about Keowee in the LRA and UFSAR it was not apparent whether all the major systems that are used for emergency power generation are within the scope of license renewal in accordance with 10 CFR 54.4. In RAI 2.5.13-2, the staff requested that the applicant identify the missing systems/components that are required for the intended function of emergency power generation.

In Attachment 2A of a letter, dated February 17, 1999, the applicant provided a description and figures of the major systems/components relied upon for the generation of emergency power from Keowee. The components are turbine, governor, excitation/voltage regulation, generator output breakers, Keowee emergency start and control, protective relaying, and auxiliary power. Furthermore, the applicant stated that all of the SSCs relied upon for the generation of emergency power from Keowee are within the scope of license renewal in accordance with 10 CFR 54.4. Those systems and components, that are within the scope of license renewal but not discussed in the LRA, were screened out in accordance with 10 CFR 54.21. For mechanical components, the screening process described in Section 2.5.2 of Exhibit A of the LRA was performed to identify the components that are subject to an AMR. The results of the screening process are listed in Table 2.5-23 of the LRA. The screening process for structures is described in Section 2.2.1.2 of the LRA and for structure components in Section 2.7.1. The screening process for electrical components is described in Section 2.6 of the LRA and in the response to RAI 2.6-1. The staff reviewed this response and found it acceptable in establishing all systems/components of Keowee being within the scope of license renewal in accordance with 10 CFR 54.4.

Some components that are common to many systems, including Keowee systems, have been evaluated in the separate sections of the LRA that address those components for the entire plant. Therefore, the following components were not evaluated in the sections that discuss individual systems:

- structural supports for piping, cables, and components that are included in Section 2.7 of Exhibit A of the LRA and evaluated in Section 2.2.3.6 of this SER

- electrical control and power cablings that are included in Section 2.6 of Exhibit A of the LRA and evaluated in Section 2.2.3.7 of this SER

In a response to RAI 2.5.9-2, the applicant stated that all instrumentation lines off the highlighted lines on the OLRFD drawings, through the instrument, are within the scope of license renewal. Instrumentation lines within the scope of license renewal were not highlighted on the OLRFD drawings to improve readability of the OLRFD drawings. Instrumentation lines are listed in Table 2.5-23 of the LRA as tubing. Instruments that are within the scope of license renewal but not subject to an AMR, are excluded from Table 2.5-23. On the basis of its review of Table 2.5-23 and drawings, the staff agrees with the applicant on its determination of all the instruments subject to an AMR.

In Section 2.5.2.2, "Identification of Mechanical Components Subject to an Aging Management Review," of Exhibit A of the LRA the applicant discussed the process of identifying mechanical components subject to an AMR, which is evaluated in Section 2.1 of this SER, "Methodology for Identifying Structures and Components Subject to Aging Management Review." The description of the screening process in Section 2.5.2.2 of the LRA was not clear to the staff. In RAI 2.5.2-1, the staff asked the applicant to clarify its screening process. The applicant's response to the RAI was found to be acceptable as discussed in Section 2.1.3 of this report.

In conjunction with the review of the methodology as discussed in Section 2.1 of this report, the staff proceeded with its review of the list of components in the Keowee systems that are subject to an AMR. In Section 2.5.13 of the LRA, the applicant stated that the mechanical components and their intended functions for the systems in this section are identified in Table 2.5-23, "Components of Keowee Hydroelectric Station Systems and Their Intended Functions." Neither the LRA statement nor the title of Table 2.5-23 indicates that the list in Table 2.5-23 is the one that presents "all the components subject to an AMR." The staff determined that Table 2.5-23 specifically listed the mechanical components identified by the applicant as being within the scope of license renewal and subject to an AMR. This was confirmed in a conference call with the applicant on November 3, 1998, and is documented in a response to RAI 2.5.13-1. On the basis of its review of the components listed in Table 2.5-23 and highlighted in the drawings in accordance with the requirements stated in 10 CFR 54.21 (a)(1) and the additional information, as discussed below, the staff agrees with the applicant that all the components subject to an AMR are properly identified.

In RAI 2.5.13-2, the staff asked why the Keowee turbine was not identified in the LRA as being within the scope of license renewal nor being subject to an AMR. In the response, the applicant stated that the Keowee turbine was within the scope of license renewal because it was required for emergency power generation. However, the turbine is not like a conventional steam turbine with a steel casing, which may be subject to an AMR. The turbine in Keowee is more like a water wheel encased in the concrete structure. The rotating turbine is within the scope of license renewal in accordance with 10 CFR 54.4, but is not subject to an AMR in accordance with 10 CFR 50.21 because it performs its function with moving parts. The "turbine casing" in this case, is actually the concrete substructure of the Keowee powerhouse that is within the scope of license renewal and is subject to an AMR. The results of the AMR for this structure are presented in Section 3.7.6 of Exhibit A of the LRA. The staff concurs with the applicant on its determination of the turbine being within the scope of license renewal and the portion being subject to an AMR.

In RAI 2.5.13-3, the staff requested that the applicant justify the exclusion of the governor in the governor oil system (flow diagram KLRFD-105A-1.1) from an AMR. In a response, the applicant stated that the governor performs its function with moving parts, and thus, in accordance with 10 CFR 54.21, is not subject to an AMR. The staff concurs with the applicant on its exclusion of the governor from an AMR.

2.2.3.4.7.3 Review Findings for Keowee Hydroelectric Station

As described above, the staff has reviewed the information in the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of that review, the staff concludes that the applicant has appropriately identified the portions of Keowee station that are within the scope of license renewal in accordance with 10 CFR 54.4 and that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.2.3.4.8 Standby Shutdown Facility (SSF)

In Section 2.5.14, "Standby Shutdown Facility," of Exhibit A of the LRA, the applicant identified the systems and the components credited with performing fire protection (FP) functions that are within the scope of license renewal. It also identified which of those systems and its components within the scope are subject to an AMR. The SSF will be used when the existing plant systems or facilities of any of the three units are unavailable due to a fire. By letter dated February 8, 1999, the applicant responded to RAIs regarding the FP systems and components. On April 1, 1999, the staff participated in a telephone conference with the applicant to discuss some of the staff's questions about fire protection. A summary of the discussion that occurred is documented in a phone call summary dated April 13, 1999.

Component supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.4.8.1 Summary of Technical Information in the Application

As described in the LRA, structures and mechanical systems that 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. As required under 10 CFR 54.4(a)(3), all SSCs relied upon in safety analyses or plant evaluations to demonstrate compliance with the Commission's regulations in 10 CFR 50.48 must be included within the scope of license renewal. The applicant's FP program meets the requirements of 10 CFR 50.48 by complying with Appendix A to Branch Technical Position (Auxiliary Power Conversion System Branch) 9.5-1 (BTP (APCSB) 9.5-1)), "Guidelines for Fire Protection for Nuclear Plants Docketed Prior to July 1, 1976," and Sections III.G, III.J, and III.O of Appendix R, "Fire Protection Program For Nuclear Power Facilities Operating Prior to January 1, 1979," to 10 CFR Part 50. To satisfy Appendix A to BTP (APCSB) 9.5-1, the applicant proposed a dedicated SSF to provide an alternate means to achieve and maintain hot-shutdown conditions following a fire, sabotage, turbine building flood, station blackout, or tornado missile event.

10 CFR 50.48 requires that the applicant implement and maintain an FP program. The FP program is incorporated into various plant documents to ensure that it remains updated. Furthermore, flow diagrams are updated any time plant or licensing changes warrant a revision. As described in the LRA, the applicant used flow diagrams to indicate the evaluation boundaries for mechanical systems that were within the scope of license renewal. Mechanical components are considered to be those installed in components that contain a fluid, including air or gas. In a two-step process, the applicant identified the mechanical components subject to an AMR. First, the applicant reviewed the flow diagrams and developed a menu of mechanical component types at ONS. Secondly, the applicant identified mechanical components and component types within the evaluation boundaries that are subject to an AMR, along with their intended functions. In Section 2.5.14 of Exhibit A of the LRA, the applicant described the systems and components of the SSF that are subject to an AMR and listed their intended functions.

Structures and Components Subject to an Aging Management Review

The SSF is designed to achieve and maintain the reactor in a safe-shutdown condition within 72 hours in accordance with criteria of its design-basis events. Safe shutdown is accomplished by:

- re-establishing and maintaining cooling of the reactor coolant pump seals to ensure natural circulation and core cooling by maintaining the primary coolant system filled to a sufficient level in the pressurizer while also maintaining sufficient secondary-side cooling water

- maintaining the reactor subcritical by isolating all sources of makeup water to the RCS except from the reactor coolant makeup system, which supplies water with a sufficient boron concentration

The SSF is primarily comprised of the structure and several systems. The structure was addressed in Section 2.7.8 of Exhibit A of the LRA. The SSF mechanical systems and components were addressed in Section 2.5.14 of the LRA and reviewed by the staff in this section of the SER. Separate from the application, the applicant submitted flow diagrams whose numbers are listed in Table 2.5-24, which show the evaluation boundaries for the portions of the SSF systems that are within the scope of license renewal. The mechanical components and their intended functions for the systems in this section that are subject to an AMR are identified by the applicant in Table 2.5-25. A brief description of each system within the SSF is presented in the following paragraphs.

The Air Intake and Exhaust System was discussed in Section 2.5.14.1 of Exhibit A of the LRA. It supplies combustion air for the SSF diesel engines and removes exhaust gases from the engines. The air intake portion of the system contains a filter, a silencer assembly, and a turbocharger assembly. The filter and silencer assembly removes particulates from the air supply and reduce noise. The turbocharger assembly increases the engine horsepower and produces better fuel economy through the utilization of exhaust gases to pressurize the intake air. The exhaust portion of the system contains an exhaust silencer to reduce exhaust gas noise. Flow diagram OLRFD-137D-1.3 shows the evaluation boundaries for the portion of the air intake and exhaust system that is within the scope of license renewal. The mechanical components that perform intended functions and are subject to an AMR include a mechanical expansion joint, muffler/silencer, pipes, screens, and tubing. Each component performs a pressure boundary function and also performs, for the screen and the muffler, an additional function for filtration and noise reduction.

The Diesel Generator Fuel Oil System was described in Section 2.5.14.2 of Exhibit A of the LRA. It supplies fuel oil to each diesel engine injector for combustion and fuel injector cooling. The system operates when the diesel engine is operating and, is otherwise, normally stagnant and at ambient conditions in the SSF. Flow diagram OLRFD-135A-1.2 shows the evaluation boundaries for the portion of the diesel generator fuel oil system that is within the scope of license renewal. The mechanical components that perform intended functions and that are subject to an AMR include orifices, pipes, pump casings, strainers, tanks, tubing, and valve bodies. Each component performs a pressure boundary function and also performs for the screen, an additional function as a filter.

The Starting Air System, which was described in Section 2.5.14.8 of Exhibit A of the LRA, supplies compressed air to start the diesel engines in the SSF. The portions of the starting air system that are within the scope of license renewal are shown on flow diagrams OLRFD-137D-1.1 and OLRFD-137D-1.2. The mechanical components with intended functions subject to an AMR perform a pressure boundary function and consist of pipes, tanks, valves, and tubing.

The Drinking Water System, which was described in Section 2.5.14.3 of Exhibit A of the LRA, distributes potable water throughout the SSF. The portions of the drinking water system that are within the scope of license renewal are shown on flow diagram OLRFD-126B-1.1. The mechanical components with intended functions subject to an AMR, perform a pressure boundary function and consist of pipes, valve bodies, and hose connections.

The Sanitary Lift System, which was described in Section 2.5.14.6 of Exhibit A of the LRA, includes a network of piping that collects sanitary wastewater from drains within the SSF. The portions of the sanitary lift system that are within the scope of license renewal are shown on flow diagram OLRFD-126B-1.1. Pipes, that perform a pressure boundary function are the only mechanical components subject to an AMR.

In Section 2.5.14.7 of Exhibit A of the LRA, the applicant described the Auxiliary Service Water System (ASWS). It is a high-head, high-volume system that supplies sufficient steam generator inventory to ensure adequate decay heat removal for all three units during a station blackout, in conjunction with the loss of normal and Emergency Feedwater System flow. The SSF ASWS consists of the SSF heating, ventilation, and air conditioning (HVAC) service water subsystem and the SSF diesel engine service water subsystem. The SSF ASWS also contains the HVAC water-cooled condensers. Included in the ASWS is a submersible pump, which is a low-head, high-volume pump capable of providing adequate makeup flow from Lake Keowee to the Unit 2 CCW System piping that serves as a supply reservoir for several plant systems. This pump is only used if both the CCW flow and siphon flow are lost during an event that requires operation of the SSF. The portions of the ASWS that are within the scope of license renewal are shown on flow diagram OLRFD-133A-2.5. The mechanical components with intended functions that are subject to an AMR, perform a pressure boundary function and consist of air ejectors, annubar tubes, orifices, pipes, pump casings, SSF HVAC water-cooled condensers, strainers, tubing, and valve bodies. In addition to performing the pressure boundary function, the air ejectors perform a gas-removal function, the annubar tubes perform a throttling function, and the strainers perform a filtration function.

The Reactor Coolant Makeup System, which is described in Section 2.5.14.5 of Exhibit A of the LRA, is designed to supply reactor coolant pump seal injection flow to any of the three ONS units in the event that the normal makeup system becomes inoperable while RCS temperature is greater than or equal to 250 °F. The portions of the Reactor Coolant Makeup System that are within the scope of license renewal are shown on flow diagrams OLRFD-101A-1.5, OLRFD-101A-2.5, and OLRFD-101A-3.5. The mechanical components, with intended functions that are subject to an AMR, perform a pressure boundary function and include the following component types: accumulators, filters, orifices, pipes, pulsation dampers, pump casings, tubing, and valve bodies. In addition to the pressure boundary function, the filters perform a filtering function and the orifices perform a throttling function.

Finally, the HVAC system is discussed in Section 2.5.14.4 of Exhibit A of the LRA. This system maintains the SSF environment within a predetermined temperature range to support equipment operability. A cooling coil in the HVAC system performs a heat transfer and pressure boundary function. The portions of the HVAC system that are within the scope of license renewal are shown on flow diagram OLRFD-116N-1.1. The mechanical components with intended functions that are subject to an AMR, perform a pressure boundary function and include the grills and the pressure boundary portion of the heaters.

2.2.3.4.8.2 Staff Evaluation

10 CFR 54.21(a)(1), requires that for those SSCs within the scope of this part, as delineated in 10 CFR 54.4, the integrated plant assessment (IPA) must identify and list those SCs that are subject to an AMR. The staff reviewed Section 2.5.14 of Exhibit A of the LRA, as supplemented by a letter dated February 8, 1999, and the other documentation discussed below, to determine whether there was reasonable assurance that the applicant has appropriately identified the components and supporting systems that serve any applicable intended functions, and that have been identified as being within the scope of license renewal in accordance with 10 CFR 54.4 and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.8.2.1 Standby Shutdown Facility Within the Scope of License Renewal and Subject to an Aging Management Review

This evaluation determines whether the applicant has properly identified, for the SSF, the systems and components that are within the scope of license renewal. The staff then determines if the applicant properly identified the systems and components that are within the scope of license renewal as being subject to an AMR.

The applicant searched its licensing documents for commitments made to meet 10 CFR 50.48, and stated that any structures or components that are relied upon for meeting the commitments are included within the scope of license renewal. The applicant also reviewed flow diagrams, design-basis documents and drawings to identify portions of the SSF systems within the scope of license renewal.

The staff sampled portions of the FP safety evaluations (SEs) dated August 11, 1978, August 21, 1989, and April 28, 1983, and Section 9.5, "Other Auxiliary Systems," of the FSAR.

The staff then compared the systems and components identified from the SEs to the applicable SSF system flow diagrams to verify that required systems and components were identified within the evaluation boundaries of the flow diagrams and were not excluded from the scope of license renewal. As part of its evaluation, the staff also reviewed flow diagrams for the SSF systems to determine if there were any additional portions of the SSF systems or components located outside of the evaluation boundaries, with intended functions, that should have been identified as within the scope of license renewal.

The staff was concerned that the applicant excluded SSF components with intended functions, from within the scope of license renewal. In particular, the SSF HVAC system contains (1) a water-cooled condenser, (2) an air-cooled condenser, and (3) air-cooling coils. The applicant stated in Section 3.5.14 of Exhibit A of the LRA that the air conditioning units that contains air cooling coils and air-cooled condensers are not within the scope of license renewal, but the units with air cooling coils and water-cooled condensers are within the scope of license renewal. In a letter dated April 6, 1999, the applicant's response to RAI 3.2.1-5 stated that the SSF HVAC system is composed of the safety-related SSF air conditioning subsystem and the non-safety-related central alarm station (CAS) HVAC subsystem. The safety-related SSF air conditioning subsystem, which contains the water-cooled condenser, is within the scope of license renewal and was originally installed to supply conditioned air to the control room, computer room, response room, and battery room in the SSF. The non-safety-related CAS HVAC subsystem contains the air-cooled condensers, and was installed to maintain acceptable temperatures for equipment not within the scope of license renewal. The staff is reasonably assured, that the air conditioning units which contain air cooling coils and air-cooled condensers are not within the scope of license renewal and, that a failure of the non-safety-related CAS HVAC will not adversely affect any safety-related component or piece of equipment.

Table 1 lists the flow diagrams reviewed by the staff for the SSF systems, which show the evaluation boundaries for the portions of the SSF that are identified as within the scope of license renewal.

Table 1 Flow Diagrams Indicating Evaluation Boundaries of SSF Systems

SSF Systems	Flow Diagram
Air Intake and Exhaust System	OLRFD-137D-1.3
Diesel Generator Fuel Oil System	OLRFD-135A-1.2
Drinking Water System	OLRFD-126B-1.1
Heating, Ventilation, and Air Conditioning System	OLRFD-116N-1.1
Reactor Coolant Makeup System	OLRFD-101A-1.5 OLRFD-101A-2.5 OLRFD-101A-3.5

SSF Systems	Flow Diagram
Sanitary Lift System	OLRFD-126B-1.1
SSF Auxiliary Service Water System	OLRFD-133A-2.5
Starting Air System	OLRFD-137D-1.1 OLRFD-137D-1.2

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the portions of the SSF systems and components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4.

After the staff determined which systems and components of the SSF 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.

Using the SSF flow diagrams, the staff sampled mechanical components from the flow diagrams and compared them to the list of components with intended functions presented by the applicant in Table 2.5-19, of the LRA to verify that there were no omissions of passive, long-lived components that were subject to an AMR. The staff found examples of potential omissions of long-lived, passive components with intended functions and discusses them in the following paragraphs.

During an April 1, 1999, phone conference, the applicant was asked to clarify why portions of the Diesel Fuel Oil System and starting air system were not within the highlighted evaluation boundaries. As documented in a phone call summary dated April 13, 1999, the applicant stated that the Diesel Fuel Oil System piping, which leads directly to the diesel oil injectors from the oil day tank, are within the scope of license renewal and, therefore, should have been highlighted on flow diagram OLRFD-135A-1.2. However, the applicant considers the portion of the Diesel Fuel Oil System and starting air system supplied by the vendor to be excluded from an AMR on the basis of 10 CFR 54.21(a)(1)(i). Further evaluation by the staff revealed that this methodology also excludes the diesel engine jacket water heat exchangers from an AMR because it is part of the vendor-supplied diesel generator skid-mounted equipment. Because they are passive and long-lived, the staff does not agree that these mechanical components can be excluded from an AMR.

10 CFR 54(a)(1)(i) does not provide justification for exclusion taken by the applicant. A review of the SOCs did not identify any guidance that would allow the exclusion taken by the applicant.

However, guidance was provided in NEI 95-10, "Industry Guide for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule." In Section 2.5.1 of Exhibit A of the LRA, Duke states that "the methodology used to identify the mechanical components subject to AMR at Oconee is consistent with the guidance provided in NEI 95-10." The exclusion of the diesel engine jacket water heat exchanger, and portions of the Diesel Fuel Oil System and Starting Air System from an AMR was determined by the staff not to be consistent with NEI 95-10, Section 4.1.1, "Establishing Evaluation Boundaries," or Appendix C, Example 5. This issue was identified as Open Item 2.2.3.4.8.2.1-1.

Duke addressed this issue in a letter dated October 15, 1999. The letter stated that they reassessed their methodology to establish the diesel generator evaluation boundary at the vendor-supplied skid boundary. The original methodology consisted of the applicant drawing an enclosure around the diesel generator skid. Duke defined the active diesel generator component listed in 10 CFR 54.21(a) to include the components, within this enclosure, on the skid supplied by the vendor. As a result, the original methodology excluded passive and long-lived components that were part of the vendor-supplied diesel generator package from an AMR.

Duke concluded that drawing an enclosure around the diesel generator skid to determine the active component boundaries excludes some passive and long-lived components. As a result, Duke revised the methodology and redefined the evaluation boundaries of the diesel generator components to be at the connections of the engine, turbocharger, air motors, and generator. As a result of the revised methodology, the staff's review has expanded to include the following additional SSF subsystems and components with intended functions, that are subject to an AMR. The additional components discussed below are found in systems that support the diesel generator.

Air Intake and Exhaust System

The air intake and exhaust system provides combustion air for the SSF diesel engines and removes exhaust gases from the engines. Flow diagram OLRFD-137D-1.3 identifies the mechanical components of the air intake and exhaust system with intended functions. The original methodology identified that the entire system was subject to an AMR. Therefore, when Duke revised the component boundary from the skid connection to the engine connection, no additional mechanical components with intended functions that are subject to an AMR were identified.

Diesel Jacket Water Cooling System

The Diesel Jacket Water Cooling System removes heat from the SSF diesel engines when the engines are operating. The system also maintains the engines at standby temperatures when the engines are shutdown. The original methodology excluded the diesel engine jacket water heat exchangers from an AMR on the basis that these components were part of the vendor-supplied diesel generator package. The revised methodology includes the Diesel Jacket Water Cooling System and components with intended functions that are subject to an AMR. Table 4 in Attachment 2 of the October 15, 1999 letter, lists the mechanical components with a pressure boundary intended function. These components are flexible hoses, heat exchanger channels, heat exchanger shells, heat exchanger tubing, heat exchanger tube sheets, immersion heaters, piping, pump casing, sight glass, tanks, tubing, and valve bodies. The heat exchanger tubing also performs a heat transfer intended function.

SSF Diesel Generator Fuel Oil System

The SSF fuel oil system supplies fuel oil to each diesel engine fuel injector for combustion and provides cooling of the fuel injector. For the original methodology, flow diagram OLRFD-135A-1.2 shows the evaluation boundaries of the fuel oil system which identified the mechanical components with intended functions. When Duke revised the component boundary from the skid connection to the engine connection, additional mechanical components with intended functions that are subject to an AMR were identified. Table 5 in Attachment 2 of the October 15, 1999 letter, lists the mechanical components that perform pressure boundary intended functions. These components are flexible hoses, pipes, pump casing, sight glass, strainers, tubing, and valve bodies. The strainers also provide a filtration intended function.

SSF Diesel Generator Lube Oil System

The diesel lube oil system provides lubrication and cooling to the SSF diesel engine bearings, gears, turbocharger bearings, and cooling of the diesel engine pistons while the diesels are operating. The original methodology excluded the diesel lube oil system from an AMR on the basis that these components were part of the vendor-supplied diesel generator package. Using the revised methodology, Duke identified this system and its mechanical components with intended functions that are subject to an AMR. Table 6 in Attachment 2 of the October 15, 1999 letter, lists the mechanical components that perform pressure boundary intended functions, and include the following component types: filters, flexible hoses, heat exchanger channels, heat exchanger shells, heat exchanger tubing, heat exchanger tube sheets, orifices, pipes, pump casings, sight glass, strainers, tubing, and valve bodies. In addition, the heat exchanger tubing provides a heat transfer intended function, the orifices provide a throttle intended function, and the strainers provide a filtration intended function.

Starting Air System

The starting air system provides dry compressed air to start the SSF diesel engines. The original methodology identified the mechanical components with intended functions in flow diagrams OLRFD -137D-1.1 and OLRFD-137D-1.2. When Duke revised the component boundary from the skid connection to the engine connection, additional mechanical components were identified with intended functions that were subject to an AMR. Attachment 2, Table 7 of the October 15, 1999 letter, lists the following component types that perform pressure boundary intended functions: flexible hoses, lubricators, pipes, strainers, tubing, and valve bodies. In addition, the strainers provide a filtration intended function.

Staff Evaluation of the Revised Evaluation Boundary Methodology

This evaluation determines whether the applicant has properly identified, for the expanded review of the SSF, the additional systems and components that are within the scope of license renewal. The staff then determines if the applicant properly identified those additional systems and components that are within the scope of license renewal as being subject to an AMR.

As previously stated, Duke revised their evaluation boundary methodology to include the components located on the diesel generator skid. The applicant's LRA flow diagrams used for the staff's review and preparation of the June 16, 1999, SER, were still appropriate for the review of the additional systems and components.

The staff reviewed portions of Section 9.5, "Other Auxiliary Systems," of the FSAR. For each system noted above, the staff compared the additional components included within the scope of license renewal due to the revised evaluation boundary, to the FSAR and applicable SSF flow diagrams. As part of its evaluation, the staff also reviewed portions of flow diagrams and FSAR Figure 9-37, "SSF HVAC SWS & SSF Diesel Cooling Water System," and Figure 9-38, "SSF Diesel Air Starting System," to verify that there were not any additional portions of the SSF systems or components located outside of the evaluation boundaries, with intended functions, that should have been identified as within the scope of license renewal. The staff found no omissions of portions of systems that should have been identified within the scope of license renewal. On the basis of this review, the staff has reasonable assurance that the additional components with intended functions were identified and that none were excluded from the scope of license renewal. Therefore, Open Item 2.2.3.4.8.2.1-1 is closed.

Finally, the staff sampled SCs from the flow diagrams and compared them to the list of components with intended functions presented by Duke in Tables 4, 5, 6, and 7 of Attachment 2 of the letter dated October 15, 1999. The purpose of this review was to verify that there were no omissions of passive, long-lived components that are subject to an AMR.

The staff was concerned that Duke's application of the revised methodology incorrectly excluded the motor air coolers and oil coolers, from an AMR. 10 CFR 54.21(a) lists motors as active components which do not require an AMR. However, some large motors may contain motor air coolers or oil coolers, or both. Air coolers provide cooling to the air surrounding the stator and oil coolers provide cooling to the lubricating oil which removes heat from the motor bearing. They are both located inside the motor enclosure with connections at the motor surface for cooling water system connection. The performance of these items connected to the motor are measured by the performance of the motor. Since the motor air coolers and oil coolers integral to large motors are part of the motor enclosure, the staff concludes that these components are not subject to an AMR in accordance with 10 CFR 54.21(a).

As a result of Duke's revised methodology, the staff concludes that there is reasonable assurance that the applicant has appropriately identified those portions of the SSF systems and its components with intended functions, that are within the scope of license renewal. The staff is also reasonably assured that there were no omissions of passive, long lived components that were subject to an AMR.

Table 2 categorizes the types of mechanical components that the applicant identified for the SSF systems that have passive, long-lived components and are subject to an AMR.

Table 2 Components of the SSF Systems and Their Intended Functions

Mechanical Component	Intended Function (s)
Air Intake and Exhaust System	
Muffler/Silencer (Carbon Steel)	Pressure Boundary, Noise Reduction
Mechanical Expansion Joint (Chrome-Molybdenum)	Pressure Boundary
Pipe (Carbon Steel, Chrome-Molybdenum)	Pressure Boundary
Screen (Carbon Steel, Chrome-Molybdenum)	Pressure Boundary, Filtration
Tubing (Carbon Steel)	Pressure Boundary
Diesel Generator Fuel Oil System	
Orifice (Stainless Steel)	Pressure Boundary
Pipe (Stainless Steel)	Pressure Boundary
Pump Casing (Carbon Steel)	Pressure Boundary
Strainer (Stainless Steel)	Pressure Boundary, Filter
Tank	Pressure Boundary
Tubing (Carbon Steel, Brass, Copper, Stainless Steel)	Pressure Boundary
Valve Bodies (Stainless Steel)	Pressure Boundary
Sight Glass (Glass)	Pressure Boundary
Flexible Hose (Stainless Steel)	Pressure Boundary
Drinking Water System	
Hose Connection (Stainless Steel)	Pressure Boundary
Pipe (Stainless Steel)	Pressure Boundary
Valve Bodies (Stainless Steel)	Pressure Boundary
Heating, Ventilation and Air Conditioning	
Air Flow Monitor (Aluminum, Galvanized Steel, Stainless Steel)	Pressure Boundary
Air Handling Unit (Aluminum, Galvanized Steel)	Pressure Boundary
Cooling Coil (except the SSF HVAC Condensers) (Aluminum, Copper)	Pressure Boundary
Ductwork (Aluminum, Galvanized Steel, Stainless Steel)	Pressure Boundary
Filter (Aluminum, Galvanized Steel, Stainless Steel)	Pressure Boundary
Grill (Aluminum, Galvanized Steel, Stainless Steel)	Pressure Boundary

Heater (PB only) (Aluminum, Galvanized Steel, Stainless Steel)	Pressure Boundary
Reactor Coolant Makeup System	
Accumulator (Stainless Steel)	Pressure Boundary
Filter (Stainless Steel)	Pressure Boundary, Filter
Orifice (Stainless Steel)	Pressure Boundary, Throttling
Pipe (Stainless Steel)	Pressure Boundary
Pulsation Damper (Stainless Steel)	Pressure Boundary
Pump Casing (Stainless Steel)	Pressure Boundary
Tubing (Stainless Steel)	Pressure Boundary
Valve Bodies (Stainless Steel)	Pressure Boundary
Sanitary Lift System	
Pipe (Stainless Steel)	Pressure Boundary
SSF Auxiliary Service Water System	
Air Ejector (Stainless Steel)	Pressure Boundary, Gas Removal
Annubar Tube (Stainless Steel)	Pressure Boundary, Throttling
Orifice (Stainless Steel)	Pressure Boundary, Throttling
Pipe (Carbon Steel, Stainless Steel)	Pressure Boundary
Pump Casing (Carbon Steel, Cast Iron)	Pressure Boundary
SSF HVAC water-cooled condensers (90-10 Copper/Nickel, Carbon Steel)	Pressure Boundary
Strainer (Carbon Steel, Stainless Steel)	Pressure Boundary, Filtration
Tubing (Stainless Steel)	Pressure Boundary
Valve Bodies (Carbon Steel, Stainless Steel)	Pressure Boundary
Diesel Jacket Water Cooling System	
Flexible Hose (Carbon Steel)	Pressure Boundary
Heat Exchanger Channel (Carbon Steel)	Pressure Boundary
Heat Exchanger Shell (Carbon Steel)	Pressure Boundary
Heat Exchanger Tubing (Admiralty Brass)	Pressure Boundary, Heat Transfer
Heat Exchanger Tube Sheets (Carbon Steel)	Pressure Boundary
Immersion Heater (Carbon Steel)	Pressure Boundary
Piping (Carbon Steel)	Pressure Boundary
Pump Casing (Carbon Steel, Stainless Steel))	Pressure Boundary
Sight Glass (Glass)	Pressure Boundary
Tank (Carbon Steel)	Pressure Boundary
Tubing (Carbon Steel, Stainless Steel)	Pressure Boundary
Valve Bodies (Carbon Steel, Stainless Steel)	Pressure Boundary
Diesel Lube Oil System	
Filter (Carbon Steel)	Pressure Boundary, Filtration
Flexible Hose (Carbon Steel)	Pressure Boundary

Structures and Components Subject to an Aging Management Review

Heat Exchanger Channel (Carbon Steel)	Pressure Boundary
Heat Exchanger Shell (Carbon Steel)	Pressure Boundary
Heat Exchanger Tubing (Admiralty Brass)	Pressure Boundary, Heat Transfer
Heat Exchanger Tube Sheets (Carbon Steel)	Pressure Boundary
Orifice (Stainless Steel)	Pressure Boundary, Throttle
Pipe (Carbon Steel, Stainless Steel)	Pressure Boundary
Pump Casing (Carbon Steel)	Pressure Boundary
Sight Glass (Glass)	Pressure Boundary
Strainers (Carbon Steel, Stainless Steel)	Pressure Boundary, Filtration
Tubing (Carbon Steel, Stainless Steel)	Pressure Boundary
Valve Bodies (Carbon Steel, Stainless Steel)	Pressure Boundary
Starting Air System	
Flexible Hose (Stainless Steel)	Pressure Boundary
Lubricator (Carbon Steel)	Pressure Boundary
Pipe (Carbon Steel)	Pressure Boundary
Strainers (Cast Iron, Monel)	Pressure Boundary, Filtration
Tubing (Carbon Steel, Stainless Steel)	Pressure Boundary
Valve Bodies (Carbon Steel, Stainless Steel)	Pressure Boundary

Consumable Issue and the Fire Detection Cables and Connections

The staff's review of the LRA led to the finding of two other FP issues, unrelated to the evaluation of the SSF structure, for which the applicant excluded certain fire protection components from an AMR.

The first example is contained in Section 2.6.6.1.2 of Exhibit A of the LRA. The applicant identified insulated cables and connections used for fire detectors as part of the fire detection system, and excluded them from an AMR because they are replaced on the basis of performance or condition programs. The staff does not agree that these cables can be excluded from an AMR. This issue was being tracked by open item 2.2.3.7-1 in the June 1999, version of this report. Further discussion of this issue is presented in Section 2.2.3.7 of this SER.

Also, the staff expressed concern in RAI 2.2-5 that hoses, scott air packs, and fire extinguishers were not considered to be subject to an AMR. In its response to this question, the applicant stated that these components are considered to be consumables. Consumables are materials and supplies expended during normal operation or maintenance of SSCs. In a letter to NEI dated April 10, 1999, the staff provided a position on consumables. The staff's position, which is documented in this letter and consistent with the SOC, allows the applicant to exclude hoses, scott air packs, and fire extinguishers based on the site specific justifications provided. Specifically, the applicant's FP program complies with applicable National Fire Protection Association (NFPA) standards, which specify performance and condition monitoring programs for these specific components. The FP program determines the replacement of the fire hoses, scott air packs, and fire extinguishers and these consumables are routinely checked by inspections performed under the FP program. Fire hoses are inspected and pressure tested periodically and must be replaced if they do not pass the test or inspection. Scott air packs are periodically tested and must be replaced if they do not pass the test. Each fire extinguisher has a qualified life and must be replaced at the end of the qualified life. The staff is satisfied that the applicant is consistent with the staff's consumable position dated April 10, 1999, and that these components are not subject to an AMR.

2.2.3.4.8.3 Review Findings for Standby Shutdown Facility

On the basis of its review, the staff concludes that there is reasonable assurance that the applicant has appropriately identified the systems and components from the SSF that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.9 Essential Siphon Vacuum System and Siphon Seal Water System

By letter dated September 30, 1999, the applicant submitted an amendment to the LRA to identify the changes to the CLB in accordance with the requirements of 10 CFR 54.21(b). As part of the CLB change, the applicant added the Essential Siphon Vacuum (ESV) System and the Siphon Seal Water (SSW) System to the LRA. The ESV and SSW Systems are newly installed as a result of the plant modifications under the Oconee service water (OSW) project. The applicant indicated that the ESV and SSW Systems and their associated components are within the scope, and subject to an AMR for license renewal.

2.2.3.4.9.1 Summary of Technical Information in the Application

The function of the ESV System is to remove any trapped air and gases from the emergency condenser circulating water (ECCW) siphon headers during normal operation and following an event involving loss of offsite power (LOOP). The ECCW System is a siphon system that is a subsystem of the CCW System. Since the CCW pumps are load shed during a LOOP, the ECCW System has a safety function of providing cooling water to the low pressure service water (LPSW) pumps, following a LOOP, using a siphon or gravity as the motive force. Siphon flow to the LPSW pumps is controlled by the lake water level and the CCW System alignment. Therefore, the ESV System is designed to increase the reliability and duration of the ECCW System first siphon supply to the LPSW System. A minimum flow line to the ESV pump is provided on the ESV receiver tank to ensure that a minimum amount of air can pass through the ESV pump. Without this minimum air, the vacuum created in the ESV pump will cause cavitation that will degrade the pump over a long period of operation. During emergency operation, the ESV pump minimum flow line is isolated and the ESV pumps remove any air that possibly accumulated in the ECCW siphon headers. This will allow ESV pumps to be directed at full capacity toward the ECCW siphon headers until the event is mitigated.

Structures and Components Subject to an Aging Management Review

The ESV System consists of three liquid-ring vacuum pumps per unit. The liquid-ring vacuum pump requires a continuous supply of seal water in order to create a vacuum. This sealing water is provided by the SSW System. Two pumps connect to the two ESV receiver tanks and the third pump in between is a spare. The two receiver tanks are connected to the CCW intake headers (one tank per header). The ESV pumps are controlled from the control room where the pump operation status and vacuum tank pressure indication are shown. The applicant stated in its submittal that the portions of the ESV System that fall within the scope of license renewal are Oconee system piping Class F. The Class F components are designed to remain intact following a design-basis earthquake without a loss of function. The materials for the components are stainless steel with glass installed in a level glass. The mechanical components of the ESV System and their intended functions are listed in Table 1-1 of the LRA Amendment.

The function of the SSW System is to provide a seal water supply to the liquid-ring vacuum pumps of the ESV System. It also provides sealing and cooling water to the CCW pump shaft seal and motor bearing cooler. The SSW System consists of two SSW headers that are routed from the LPSW System in the turbine building to the CCW intake structure. Both the SSW headers are normally in service, but only one header is required to supply all loads. The piping of the SSW System falling within the scope of license renewal are also Oconee system piping Class F. The mechanical components of the SSW System and their intended functions are listed in Table 1-2 of the LRA Amendment.

2.2.3.4.9.2 Staff Evaluation

The staff reviewed the applicant's submittal for the LRA amendment and supporting information to determine whether there is reasonable assurance that the applicant has appropriately identified the components of the ESV and SSW Systems that are within the scope of license renewal, pursuant to10 CFR 54.4, and identified the components within the scope of license renewal, and subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.9.2.1 Essential Siphon Vacuum System and Siphon Seal Water System Within the Scope of License Renewal and Subject to Aging Management Review

As part of its evaluation, the staff reviewed Section 1.1, "Mechanical Integrated Plant Assessment," of the LRA Amendment and the supporting information in Section 9.2.2.2.5 of the ONS UFSAR, flow diagrams, and the previous technical specification change (#96-09) submittal for the upgraded ECCW System (dated August 28, 1999) to determine if there were any other components within the systems that the applicant should have identified in the LRA Amendment as within the scope and subject to an AMR for license renewal. The staff reviewed the mechanical components and their intended functions listed in Table 1-1 (for the ESV System) and Table 1-2 (for the SSW System) of the LRA Amendment. The staff compared the information in the tables with the cited supporting information to verify that all the components having intended functions were not omitted from consideration within the scope of the rule.

In Table 1-1, the mechanical components of the ESV System identified as subject to an AMR include the following component types: pumps, tanks, level glass, valves, orifices, pipes, and tubing. In Table 1-2, the mechanical components of the SSW System identified as subject to an AMR include the following component types: annubar, orifices, pipes, strainers, valves, and tubing. The applicant indicated in the tables that maintaining pressure boundary is the only passive function associated with these mechanical components except the strainer. The intended functions of the strainers are pressure boundary and filtration. The staff asked the applicant why it did not list other components that perform additional functions. For example, the orifice and annubar have the throttling function in addition to maintaining a pressure boundary. The applicant responded to the staff's questions via an e-mail, which was documented in a RAI response summary, dated November 18, 1999. The applicant stated that only the component's intended functions required in support of the system intended functions within the scope of license renewal are listed. Throttling of the orifice and annubar is to create a differential pressure for flow measurement which is not required to support the system's intended function. The staff agrees with the applicant's rationale because the additional function does not support the system's intended function required by 10 CFR 54.4.

The applicant also submitted flow diagrams OFD-130A-1.1, 2.1, and 3.1 for the ESV System, and OFD-129A-1.1, -1.2, -2.2, and -3.2 for the SSW System on October 28, 1999 (without cover letter) for the staff to verify the applicant's scoping results. The applicant highlighted the boundaries of the flow diagrams to identify the components within the scope of license renewal. The staff compared the flow diagrams with the information in the LRA Amendment and identified an open item regarding the omission of the air/water separators from the scope. The air/water separators connected to the pumps are neither highlighted on the drawings nor listed in Table 1-1 of the LRA Amendment. The staff questioned the applicant whether the air/water separators are within the scope and subject to AMR for license renewal. In its response by an e-mail (which was documented in the RAI summary of November 18, 1999), the applicant stated that the air/water separators are part of the pump casings and do not have a unique equipment number. They are evaluated with the pump casing and are not listed separately. The staff finds that the air/water separators are within the scope and subject to an AMR for license renewal as part of the ESV pumps. Therefore, no omissions by the applicant were found. On the basis of this review, the staff has reasonable assurance that the applicant has properly identified the components of the ESV and SSW Systems that are subject to an AMR.

2.2.3.4.9.3 Review Finding for Essential Siphon Vacuum System and Siphon Seal Water System

The staff has reviewed the information provided in Section 1.1 of the LRA Amendment and the additional information provided by the applicant in response to the staff's questions and did not find any omissions by the applicant. Therefore, the staff concludes that there is a reasonable assurance that the applicant has adequately identified those portions of the ESV and SSW Systems and associated components that fall within the scope of license renewal, pursuant to 10 CFR 54.4(a), and that are subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

2.2.3.4.10 Chilled Water System

In a letter dated October 15, 1999, the applicant responded to SER Open Item 2.2.3.4.3.2.1-1, concerning the Chilled Water (WC) System. The applicant committed to include the WC System within the scope of license renewal and identified all SCs that are within the scope of license renewal. The WC System is located in the auxiliary and turbine buildings. The applicant also identified SCs that are within the scope and subject to an AMR.

Component (equipment and piping) supports for the systems listed above are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the systems are presented in Section 2.6, "Electrical Components," of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6.9 and 2.2.3.7 of this report. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, rules for identifying components within the scope of license renewal in OLRP-1002 specifically state that instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow. The applicant included instrument line components with the system to which they are attached.

2.2.3.4.10.1 Chilled Water System Summary of Technical Information in the Application

The primary function of the WC System is for the Control Room Area Ventilation and Air Conditioning System (CRACS) to maintain control room and control area temperatures within the prescribed limits. The system ensures cooling of vital equipment by providing chilled water to various cooling coils in the CRPFS. ONS has two redundant trains of CRACS and WC Systems to ensure that one train of each system is available, assuming a single active failure disables the other train in one or both systems. The requirement that the WC System withstand a single active failure is addressed in UFSAR Section 3.11.4, "Loss of Ventilation." The requirement to have two trains of WC System operable is addressed in Section 3.7.16, "Control Room Area Cooling Systems (CRACS)" of the ONS Improved Technical Specifications. While the WC System is addressed in the ONS CLB, a loss of WC System event is not.

Each WC System train consists of a chiller with associated evaporator coil, condensing coil, refrigerant piping, and compressor, and associated system piping and instrumentation. The CCW System provides cooling water to the control room ventilation chillers and is discussed in Section 2.2.3.4 of this report. The license renewal portions of the WC System are designed and constructed to the requirements of ONS Piping Class G. Class G piping and components are not designed to remain operable during and following a seismic event (see Table 2.5-1 of Exhibit A of the Application). The materials of construction of this system are brass, carbon steel, cast iron, copper, galvanized steel and stainless steel. The tubes of the heat exchanger in the evaporator and condenser are constructed of copper.

The applicant described its process for identifying the mechanical components subject to an AMR in Section 2.5.2, "Detailed Process Description," of Exhibit A of the LRA. As stated above, the applicant committed to include the WC System within the scope of license renewal. As a consequence of adding the WC System, the applicant stated that an integrated plant assessment has been performed on the WC System. The WC System is capable of providing the cooling function in control rooms and control areas during design-basis-events without a loss of off-site power. In the letter dated October 15, 1999, the applicant stated in response to SER Open Item 2.2.3.4.3.2-1 that the WC System is non-safety-related and engineering analysis showed that its loss of function during a design-basis event can be withstood for 24 hours, upon which time several options of compensatory actions exist.

The applicant conforms with the requirements of 10 CFR 50.63, "Station Blackout," by having a four hour coping capability for ONS Units 1, 2, and 3. The WC System is capable of providing the cooling function to maintain the control rooms and control areas at the operating temperature limits of the equipment required to operate during a station blackout scenario. These portions of the WC System are within the scope of license renewal.

On the basis of its methodology described above, the applicant identified the portions of the WC System that are within the scope of license renewal on flow diagrams OFD-133A-1.1, OFD-136J-1.5, OFD-136J-1.6, and OFD-136J-3.3. Using the methodology described in Section 2.5.2.2, "Identification of Mechanical Components Subject to an Aging Management Review," of Exhibit A 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. In Table 1 of Section 4 of the letter dated October 15, 1999, the applicant listed the WC System SCs subject to an AMR in response to SER Open Item 2.2.3.4.3.2.1-1. The applicant identified the following 19 component types as subject to an AMR: compressor, cooling coil tube, cooling coil header, condensing heat exchanger channel, condensing heat exchanger shell, condensing heat exchanger tube, condensing heat exchanger tube sheet, evaporator heat exchanger channel, evaporator heat exchanger shell, evaporator heat exchanger tube, evaporator heat exchanger tube sheet, orifice, pipe, pump casing, sight glass, strainers, tank, tubing, and valve bodies. The applicant identified maintaining pressure boundary as the intended function for each component. Additionally, the applicant identified maintaining heat transfer as the intended function for the cooling coil tube, condensing heat exchanger tube, and evaporator heat exchanger tube and components.

2.2.3.4.10.2 Staff Evaluation

The staff reviewed Section 2.5.6 of Exhibit A of the LRA to determine whether there is reasonable assurance that the applicant appropriately identified the chilled water system components and supporting structures within the scope of license renewal in accordance with 10 CFR 54.4; and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued questions concerning the WC System scoping. The staff's questions and the applicant's responses are documented in a summary dated November 5, 1999.

2.2.3.4.10.2.1 Chilled Water System Structures and Components Subject to an Aging Management Review

The staff reviewed the text and diagrams submitted by the applicant in the letter dated October 15, 1999 and the ONS UFSAR to determine if there are portions of the system piping and other components that the applicant did not identify as being within the scope of license renewal that are required to perform intended functions. Essentially, all WC System components perform at least one intended function and, therefore, are within the scope of license renewal and are identified as such by the applicant in the letter dated October 15, 1999. For scoping review, the staff focused on those SCs of the WC System that were not identified as being within the scope of license renewal to verify that they do not have any intended functions that meet the scoping requirements of 10 CFR 54.4. The staff also reviewed the UFSAR to determine if there were any additional system functions that were not identified as intended functions and verified that those additional functions did not meet the scoping requirements of 10 CFR 54.4.

The staff then determined whether the applicant had properly identified the SCs subject to an AMR from among those identified as within the scope of license renewal. In Table 1 of Section 4 of the letter dated October 15, 1999, the applicant listed the WC System SCs subject to an AMR in response to SER Open Item 2.2.3.4.3.2.1-1. The staff evaluated the applicant's scoping and screening methodology and documented its findings in Section 2.1 of this SER. The staff sampled from the list of SCs identified by the applicant as subject to an AMR for the WC System to obtain reasonable assurance that all components subject to an AMR were appropriately identified. 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 a configuration change or were subject to replacement on the basis of a qualified life or a specified time period (i.e., active or short-lived).

In Table 1 of Section 4 to the letter dated October 15, 1999, the applicant listed the mechanical components subject to an AMR and their intended functions. The applicant also provided four detailed flow diagrams OFD-133A-1.1, 116J-1.5, 116J-1.6, and 116J-3.3 of the WC System. The applicant highlighted the flow diagrams to identify those portions of the 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 flow diagrams to the system drawings and descriptions in the UFSAR to ensure they were representative of the WC System. The staff sampled portions of the flow diagrams that were not highlighted to ensure that these components did not perform any intended functions defined in 10 CFR 54.4. Based on this review, the staff issued questions concerning the WC System scoping based on the information submitted by the applicant for the WC System in the letter dated October 15, 1999. The staff's questions and Duke's responses are documented in the letter dated November 5, 1999. Specifically, the staff questioned whether the scoping boundary ended at the end of valve "WC-40" on drawing OFD-116J-1.6. The applicant responded that the valve WC-40 is the supply side isolation valve for chilled water supply to the administrative building. This portion of the WC System (from the end of valve

"WC-40" and beyond to the administrative building) is not within the scope of license renewal. In the event isolation of the chilled water system is necessary, WC-40 can be closed by manual action and does not result in the loss of cooling function to the control room. The staff agrees with the applicant's conclusion that valve WC-40 can be closed by manual action as part of the boundary isolation function and that the chilled water supply to the administrative building is not in the scope of license renewal.

The staff compared Table 3 of Attachment 2 of the letter dated October 15, 1999, to Table 2.5-13 of the LRA, and questioned which portions of the CRPFS have been added to the scope of license renewal as a result of the addition of the WC System. The applicant responded that portions of CRPFS ducting, previously considered outside the scope license renewal, now have intended functions and are included within the scope. The applicant noted that although new portions of the CRPFS have been added to the scope of license renewal due to the inclusion of the WC System and its intended functions, the new component types are already included in Table 2.5-13 of the LRA. Therefore, no new component types have been added to the list of components within the scope of license renewal. The staff sampled components within the revised boundary of the CRPFS, expanded as a result of inclusion of the WC System, and agrees that it includes the SCs that are within the scope of license renewal in accordance with 10 CFR 54.4. The staff also agrees that the SCs within the scope of license renewal for the CRPFS are already included on Table 2.5-13 of the LRA.

On the basis of a review of the letter dated October 15, 1999, supporting information in the UFSAR, and the applicant's responses to the staff's question concerning those WC System components serving the administrative building (high lighted in flow diagram OLRFD-116J-1.1 at the end of valve WC-40) that are not within the scope of license renewal, the staff has reasonable assurance that the applicant has identified all portions of the WC System on the flow diagrams provided, that are within the scope of license renewal and meets the criteria of 10 CFR 54.4.

Using the information presented on the flow diagrams for the WC 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 (Table 1 of Attachment 2 to the letter dated October 15, 1999) from among those identified as within the scope of license renewal. The staff verified that the passive, long-lived components highlighted on the system flow diagrams appeared on the list of components subject to an AMR for the WC System in Table 1 Attachment 2 to the letter dated October 15, 1999. No omissions were identified. On the basis of this review, the staff has reasonable assurance that the applicant has identified the SCs of the WC System subject to an AMR.

2.2.3.4.10.2.2 Review Findings for WC System

On the basis of its evaluation, the staff concludes that there is reasonable assurance that the applicant has identified and listed the portions of the WC System, and the associated SCs thereof, that are 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.

2.2.3.5 Steam and Power Conversion Systems

2.2.3.5.1 Steam and Power Conversion Systems

In Section 2.5.9, of Exhibit A of the LRA the applicant described steam and power conversion systems. These systems were designed to remove heat from the RCS, and include the following: Main Steam System, Condensate System, Emergency Feedwater System, and Feedwater System.

Component supports for the systems are presented separately in Section 2.7 of Exhibit A of the LRA. Electrical components that support the operation of the system are presented in Section 2.6 of Exhibit A of the LRA. The staff evaluated component supports and electrical components in Sections 2.2.3.6 and 2.2.3.7 of this SER. Although instrument lines are not individually highlighted as being within the scope of license renewal on the flow diagrams in OLRP-1002, instrumentation line components (e.g., tubing, valves) are within the scope if the lines are normally open to process flow, as stated in the rules for the identification of components within the scope of license renewal in OLRP-1002. The applicant evaluated instrument line components with the system to which they are attached.

2.2.3.5.1.1 Summary of Technical Information in the Application

The steam and power conversion systems are described in Chapter 10 of the ONS UFSAR. In Section 2.5.9, of Exhibit A of the LRA, the applicant identified the following four portions of the steam and power conversion systems and their components that are within the scope of license renewal:

- Main Steam System
- Condensate System
- Emergency Feedwater System
- Feedwater System

Table 2.5-14 of Exhibit A of the LRA identified flow diagrams for these four systems, highlighting the evaluation boundaries for those portions of the steam and power conversion systems that are within the scope of license renewal. The applicant used the screening process described in Section 2.5.2 of Exhibit A of the LRA to determine which components are subject to an AMR, and listed those components and their intended functions in Table 2.5-15.

The Main Steam System transports dry, superheated steam from the steam generators to the main turbine and main feedwater pump turbines. The system supplies steam to drive the emergency feedwater pump (EFWP) turbine during emergency operation and various other components during normal operation. The system is relied upon to dissipate heat from the RCS following a load rejection, a turbine trip, or a reactor trip by dumping steam to the condenser or atmosphere, or both. The system is also used to achieve normal cooldown to Low-Pressure Injection System initiations. The components of the Main Steam System that were identified by the applicant for license renewal are highlighted in the flow diagrams of OLRFD-122A-1.1 through 122A-1.5, OLRFD-122A-2.1 through 122A-2.5, OLRFD-122A-3.1 through 122A-3.5, OLRFD-122B-1.1, 122B-2.1, and 122B-3.1. Listed in Table 2.5-15 of Exhibit A of the LRA as components subject to an AMR include the following: EFWP turbine casing, filter, orifice, pipe, tubing, and valve bodies. The intended function for all the components is maintaining the pressure boundary.

The Condensate System delivers condensate from the condenser hotwells to the suction of the main feedwater pumps, purifies the condensate, removes non-condensable gases from the condensate, and heats the condensate to improve overall plant efficiency. The Condensate System supplies water to the emergency feedwater pumps during emergency operation. The Condensate System is comprised of the main condenser, condensate coolers, and generator water coolers. The components of the Condensate System that were identified by the applicant for license renewal, are highlighted in the flow diagrams of OLRFD-121A-1.1 through 121A-1.8, OLRFD-121A-2.1 through 121A-2.8, and OLRFD-121A-3.1 through 121A-3.8. Listed in Table 2.5-15 of Exhibit A of the LRA, as the components subject to an AMR include the following: demineralizer, filter, mechanical expansion joint, orifice, pipe, pump casing, strainer, tanks, tubing, valve bodies, main condenser, condensate coolers, and generator water coolers. The intended function for all of these components is maintaining the pressure boundary.

The Emergency Feedwater System is designed to supply water to the steam generator in the event of a loss of both main feedwater pumps or a low steam generator level. The system ensures that a sufficient water level is maintained in the steam generator, allowing time to restore the flow of main feedwater to cool down the RCS to the point at which decay heat can be removed by the Low-pressure Injection System. The components of the Emergency Feedwater System that were identified by the applicant for license renewal are highlighted in the flow diagrams of OLRFD-121D-1.1 through 121D-1.2, OLRFD-121D-2.1, and 121D-3.1. Listed in Table 2.5-15 of Exhibit A of the LRA, as the components subject to an AMR include the following: flow nozzle, flow sensor, orifice, pipe, pump casing, tubing, and valve bodies. The intended function(s) for the flow sensor and orifice are maintaining the pressure boundary and throttle, and for all the other components is maintaining the pressure boundary.

The Feedwater System receives water from the Condensate System, increases the water pressure and temperature, and delivers the water to the steam generators at a controlled rate of flow. The system operates during accidents to provide steam generator level indication, isolates feedwater flow to a faulted steam generator to prevent containment overpressurization, and provides the feedwater pump operating status to the Reactor Protection System and the SCRAM System. The Feedwater System also provides containment isolation during accidents that require containment integrity to be maintained. The components of the Feedwater System that were identified by the applicant for license renewal are highlighted in the flow diagrams of OLRFD-121B-1.3, 121B-1.5, 121B-2.3, 121B-2.5, 121B-3.3, and 121B-3.5. Listed in

Structures and Components Subject to an Aging Management Review

Table 2.5-15 of Exhibit A of the LRA, as the components subject to an AMR include the following: the emergency feedwater header, low nozzle, main feedwater header, pipe, pump casing, and valve bodies. The intended function for all of these components is maintaining the pressure boundary.

2.2.3.5.1.2 Staff Evaluation

The staff reviewed Section 2.5.9 of Exhibit A of the LRA to determine whether there is reasonable assurance that the components of the steam and power conversion systems within the scope of license renewal and subject to an AMR, have been identified in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). After completing the initial review, the staff issued RAIs by letter dated November 21, 1998, regarding the steam and power conversion systems. The applicant responded to the RAIs in a letter dated January 25, 1999.

2.2.3.5.1.2.1 Steam and Power Conversion Systems Within the Scope of License Renewal and Subject to an Aging Management Review

As part of its evaluation, the staff reviewed Section 2.5.9 of the LRA and Chapter 10, "Steam and Power Conversion Systems," of the UFSAR, to determine if there were any additional portions of the system and other components that the applicant should have identified in the LRA as within the scope of license renewal in accordance with 10 CFR 54.4, and subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In Section 2.5.9.1 of Exhibit A of the LRA, the applicant stated that the portions of the Main Steam System piping within the scope of license renewal are designed and constructed to the requirements of Oconee System Piping Class F and G. In reviewing the Main Steam System drawings identified in Table 2.5-14 of Exhibit A of the LRA, the staff found that Class F piping was within the scope of license renewal, but most of Class G piping was outside the scope of license renewal. In RAI 2.5.9-1, the staff requested a clarification from the applicant to explain how the applicant made its determination for Class G piping. In a letter dated January 25, 1999, the applicant responded that the portions of Class G piping that are within the scope of license renewal were determined by their intended functions, as defined in 10 CFR 54.4, and were highlighted in the system drawings. The remaining Class G piping was determined not to support any intended functions as specified in 10 CFR 54.4. On the basis of its review, the staff has determined that all of the piping that was within the scope of license renewal (highlighted in the drawings) was considered to be subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

In RAIs 2.5.9-3 and 2.5.9-4, the staff requested that the applicant submit the basis for excluding the main feedwater pump turbine, upper surge tank dome (located between upper surge tanks 1A and 1B), and condensate storage tank from the scope of license renewal. The applicant responded that because these components do not support any intended functions as defined in 10 CFR 54.4, they are excluded from the scope of license renewal.

In RAIs 2.5.9-5, 2.5.9-6, and 2.5.9-7, the staff requested the basis for excluding certain portions of the piping identified in flow diagrams OLRFD-121A-1.4 "Condensate System", 121A-1.6 "Condensate System", and 121B-1.3 "Feedwater System" from the scope of license renewal. The applicant responded that the piping and components highlighted in the first two drawings are important, as related to 10 CFR 54.4, in maintaining the hotwell water supply inventory for Emergency Feedwater System supply. Failure of the piping and components that were not highlighted would not affect hotwell supply inventory since the piping and components in question do not support any system-intended functions as defined in 10 CFR 54.4. Further, in the third drawing, the applicant stated that these portions of the piping in question (upstream of valves 1FDW-41 and 32) do not support any system-intended functions as defined in 10 CFR 54.4. Therefore, the applicant determined that those portions of piping and components are excluded from the scope of license renewal.

On the basis of all the above applicant's responses, the staff agrees that the diagrams identify the system level scoping boundaries, and that those boundaries correctly separate system components within the scope of license renewal from those that are outside.

Some components that are common to many systems, including steam and power conversion systems, have been evaluated in the separate sections of the LRA that address those components for the entire plant. Therefore, the following components were not evaluated in the sections that discuss individual systems:

- structural supports for piping, cables, and components that are included in Section 2.7 of Exhibit A of the LRA and evaluated in Section 2.2.3.6 of this SER, and

- electrical control and power cabling that are included in Section 2.6 of Exhibit A of the LRA and evaluated in Section 2.2.3.7 of this SER.

In LRA Section 2.5.2.2, "Identification of Mechanical Components Subject to an Aging Management Review," the applicant discussed the process of identifying mechanical components subject to an AMR, which is evaluated in Section 2.1 of this SER, "Methodology for Identifying Structures and Components Subject to Aging Management Review." The description of the screening process in Section 2.5.2.2 of Exhibit A of the LRA was not clear to the staff. In RAI 2.5.2-1, the staff asked the applicant to clarify its screening process. The applicant's response to the RAI was found to be acceptable as discussed in Section 2.1.3 of this report.

The staff reviewed the list of components in the steam and power conversion systems that are subject to an AMR. The staff finds that the list was not clearly identified in the LRA. In Section 2.5.9 of Exhibit A of the LRA, the applicant stated that "the mechanical components and their intended functions for the systems in this section are identified in Table 2.5-15." The title of Table 2.5-15 is "Components of Steam and Power Conversion Systems and Their Intended Functions." Neither the LRA statement nor the title of Table 2.5-15 indicates that the list in Table 2.5-15 is the one that presents all the components subject to an AMR. It is unclear whether the listed components in Table 2.5-15 are "all the important components of the system," or "all the components within the scope of license renewal," or "the specific components subject to an AMR." After its review, the staff determined that Table 2.5-15 listed specifically all the mechanical components identified by the applicant as being within the scope of license renewal and subject to an AMR. This was confirmed in a conference call with the applicant on November 3, 1998, and is documented in a response to RAI 2.5.13-1. By comparing the components listed in Table 2.5-15 and the components highlighted in the drawings for each subsystem and using the requirements stated in 10 CFR 54.21 (a)(1), the staff agrees with the applicant that all the components subject to an AMR are properly identified.

In RAI 2.5.9-2, the staff asked the applicant to explain why certain instruments, which appeared to be within the scope of license renewal, were not highlighted in the diagrams. The applicant responded that all instrumentation lines off highlighted lines on the OLRFD diagrams, through the instrument, are within the scope of license renewal. Instrumentation lines within the scope of license renewal were not highlighted on the OLRFD diagrams to improve readability of the OLRFD diagrams. Instrumentation lines are listed in Tables 2.5-15 of Exhibit A of the LRA as "tubing." Instruments that are within the scope of license renewal but not subject to an AMR, are excluded from Table 2.5-15. On the basis of the applicant's response, the staff finds that the tubing is listed in Table 2.5-15 for the Main Steam System, Condensate System, and Emergency Feedwater System. In flow diagrams OLRFD-121B-1.5 and 121B-1.3 for the Feedwater System, there are many instrumentation lines off highlighted lines, such as FDWFE-0156, FDWPG-0244, FDWLT-0008, and FDWLT-0080. However, the staff found that Table 2.5-15, as related to Feedwater System, did not list any tubing, which means that the applicant has determined that all the instruments for the Feedwater System are excluded from an AMR. The staff could not find any basis for this exclusion. In RAI 2.5-1, the staff asked the applicant why the instrumentation tubing for several systems (including the Feedwater System) was excluded from an AMR. This issue is addressed in Section 2.2.3 of this report as related to the identification and listing of components associated with instrumentation lines within the scope of license renewal (RAI 2.5-1).

2.2.3.5.1.3 Review Findings for Steam and Power Conversion Systems

As described above, the staff has reviewed the information in the LRA and the additional information sent by the applicant in response to the staff's RAIs. On the basis of that review, the staff concludes that the applicant has appropriately identified the portions of steam and power conversion systems that are within the scope of license renewal in accordance with 10 CFR 54.4, and that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

2.2.3.6 Structures and Structural Components

In Section 2.7, "Structures & Structural Components," of Exhibit A of the LRA - Technical Information (OLRP-1001), the applicant identified the structures and structural components that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4 and subject to an AMR. The applicant identified the following structures as being within the scope of license renewal and subject to AMR:

- Auxiliary buildings, including hot machine shop, spent fuel pools, and the reinforced concrete tunnel between the auxiliary building and the hot machine shop
- Earthen embankments, including intake canal dike, Keowee River dam, and Little River dam and dikes
- ONS intake structure
- Keowee structures, including breaker vault, Keowee intake structure, penstock, powerhouse, service bay structure, and spillway
- Reactor buildings internal structure and the unit vent stacks
- Standby shutdown facility
- Turbine buildings, including switchgear enclosures for Units 1 & 2 (shared), and Unit 3
- Yard structures, including the areas and components outside the other buildings. The yard structures within the scope of license renewal include the following: Keowee 230 kV transmission line towers, 230 kV switchyard structures and relay house, trenches, an elevated water storage tank, Keowee transformer yard, and the ONS transformer yard.

The staff reviewed Section 2.7 of Exhibit A of the LRA to determine whether the applicant has properly identified the structures and their associated components with its methodology, which is discussed in Section 2.1, "Methodology for Identifying Structures and Components Subject to Aging Management Review," of this report such that there is reasonable assurance that the applicant has identified and listed the SCs subject to an AMR that have met the requirements stated in 10 CFR 54.21(a)(1). The staff also used the ONS's UFSAR, the site plan, and applicable design drawings to verify the information provided in Section 2.7 of Exhibit A of the LRA. The staff's review of each of the above structures is presented in the following sections.

2.2.3.6.1 Auxiliary Buildings

In Section 2.7.3, "Auxiliary Buildings," of Exhibit A of the LRA, the applicant identified the SSCs of the auxiliary buildings that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the auxiliary building SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

Structures and Components Subject to an Aging Management Review

2.2.3.6.1.1 Summary of Technical Information in the Application

The applicant determined that the auxiliary buildings were within the scope of license renewal and identified the following structures as being part of the auxiliary buildings: the auxiliary buildings, spent fuel pool, hot machine shop, and the tunnel between the auxiliary buildings and hot machine shop. As described in Exhibit A of the LRA, ONS has two auxiliary buildings; one building is shared by Units 1 and 2 and the other building is for Unit 3. The auxiliary buildings, which are free-standing reinforced concrete structures sitting on reinforced concrete mat foundations, serve as enclosures to protect the auxiliary systems, control rooms, and other systems required for the safe operation of the plant. The portions of the auxiliary buildings that house engineered safeguard systems, control rooms, fuel storage facilities, and radioactive materials are Class 1 structures. Class 1 structures are those structures which prevent uncontrolled release of radioactivity and are designed to withstand all loadings without loss of function. The applicant has determined that Class 1 structures meet the intent of 10 CFR 54.4(a)(1). Other portions of the auxiliary buildings are Class 2 structures. Class 2 structures are those structures whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown but could interrupt power generation. The applicant has determined that Class 2 structures meet the intent of 10 CFR 54.4(a)(2).

The hot machine shop and its extension are located between the Unit 1 and 2 reactor buildings and shares the reinforced concrete walls on the east and north sides with the Unit 1 and 2 spent fuel pool and fuel loading area. The hot machine shop is a reinforced concrete structure and its extension is a steel frame structure. A reinforced concrete tunnel, which runs under the Units 1 and 2 spent fuel pool, connects the auxiliary building and the hot machine shop. The tunnel provides a sheltered and shielded passage for equipment between the auxiliary building areas and the hot machine shop work area. The hot machine shop is a Class 2 structure and its extension is a QA 4 structure whose continued functions are not required during and after a seismic event.

In Table 2.7-1 of Exhibit A of the LRA, the applicant identified the structural components that are within the scope of license renewal, as well as the intended functions of each structural component. The methodology used to identify generic component types is evaluated in Section 2.1 of this report. The applicant identified a total of 35 component types within the auxiliary building as being within the scope of license renewal because they perform one or more of the following intended functions, as noted in the table:

- provide pressure boundary and/or fission product barrier
- provide structural and/or functional support to safety-related equipment
- provide shelter/protection to safety-related equipment (including radiation shielding)
- provide rated fire barrier to confine or retard a fire from spreading to or from adjacent areas
- provide source of cooling water for plant shutdown
- serve as missile (internal or external) barrier

- provide structural and/or functional support to non-safety-related equipment where failure of a structural component could directly prevent satisfactory accomplishment of any of the safety-related functions
- provide a protective barrier for internal/external flood events

The applicant determined the intended functions for these structures and structural components based on ONS's UFSAR, technical specifications, and regulated events documentation. These structural components are subject to an AMR because the intended function(s) are performed without moving parts or without a change in configuration or properties and because they are not replaced based on qualified life or specified time period .

To facilitate the structures and structural components AMRs, the applicant grouped the 35 component types into four general categories according to their operating environment and material as follows:

- Concrete components
- Steel components in an air environment
- Steel components in a fluid environment
- Fire barriers

2.2.3.6.1.2 Staff Evaluation

The staff reviewed Section 2.7.3 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the auxiliary buildings structures and structural components (as discussed in Subsection 2.2.3.6.1.1 of this report) have been properly identified as being 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(a)(1).

2.2.3.6.1.2.1 Auxiliary Buildings Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information presented in Exhibit A, Section 2.7, of the LRA, portions of the UFSAR, Chapter 3, "Design of Structures, Components, Equipment, and Systems," and applicable drawings in the UFSAR, Chapter 1, to determine if there were any structures, or associated structural components within the auxiliary buildings that the applicant did not properly identify as being within the scope of license renewal or did not properly identify as being subject to an AMR. On the basis of its review, the staff identified the finding described below.

In Section 2.7.1, "Description of Process to Identify Structural Components Subject to AMR," of Exhibit A of the LRA, the applicant included the spent fuel pool in the boundary of the auxiliary buildings. However, the spent fuel pool was not described in Section 2.7.3, "Auxiliary Buildings," of Exhibit A of the LRA, while some of its components are listed in Table 2.7-1 of Exhibit A of the LRA. It was not clear whether all the components that constitute the spent fuel pool are included in the table.

In its May 10, 1999, response to the staff RAI 2.7-11 regarding the major structural components that comprise the spent fuel pool, the applicant stated that specific aspects of structures within the auxiliary buildings, such as the spent fuel pools, were not described in the application. The spent fuel pools are described in the UFSAR, Section 9.1.2. The staff compared Table 2.7-1 of Exhibit A of the LRA with the UFSAR, Section 9.1.2.1.1 and found that the components within the spent fuel pool were included in the table.

In Section 2.7.2, "Structural Components," of Exhibit A of the LRA, the applicant did not identify water stops, expansion joints, and structural sealants or caulking as structural components that require an AMR. Section 2.7.3 of Exhibit A of the LRA states that all the below grade construction joints in the exterior walls are protected by cast-in-place water stops. In RAI 2.7-3, the staff asked the applicant why the water stops were not included within the scope of license renewal. In its response to the staff's question, the applicant stated that the water stops do not support any component intended function, and therefore, need not be subject to an AMR. The staff did not agree with the applicant's response because ground water in-leakage into the auxiliary building could occur as a result of degradation to the water stops. This leakage may cause flooding of equipment within the scope of license renewal (UFSAR Section 3.4.1, "Flood Protection," discusses the effect of flooding). Water stops perform its function without any moving parts, or change in configuration or properties. The auxiliary building water stops are built into the concrete at the expansion joints that are not replaceable after construction. Therefore, water stops should be subject to an AMR. Water stops are also subject to age related degradation, and should require aging management during the period of extended operation.

As discussed in Section 3.8.3.1 of this report, expansion joints, structural sealants or caulking are nonmetallic components that play important roles in maintaining the integrity of the components to which they are connected. As stated in the staff's position regarding consumables (see License Renewal Issue No. 98-0012, "Consumables," dated April 20, 1999), structural sealants that are within the scope of license renewal typically meet the requirements under 10 CFR 54.21(a)(1)(i) and (a)(1)(ii). Structural sealants are often required for the structural integrity of containment and other safety-related structures. Expansion joints and structural sealants perform its intended function(s) without any moving parts, or change in configuration or properties and are not typically subject to periodic replacement based on qualified life or specified time period. They are relied upon for decades of service and material aging degradation may occur. Therefore, water stops, expansion joints, and structural sealants should be subject to an AMR. This was identified as Open Item 2.2.3.6.1.2.1-1.

In its response of October 15, 1999 to Open Item 2.2.3.6.1.2.1-1, the applicant stated that the caulking, sealants, and water-stops were not considered as structures or components. However, these materials are important in maintaining the integrity of the components to which they are connected. The intended functions of the structure or component supported by these materials are to (1) maintain pressure boundary for the control room, (2) provide fire barrier penetration seal, and (3) provide a flood barrier. Aging of the control room boundary walls, ceiling, and floor is managed by the Inspection Program of Civil Engineering Structures and Components (the Inspection Program) which is addressed in Section 4.19 of Exhibit A of the LRA. Reinforced concrete walls located below grade and flood curbs in the auxiliary building are sealed with caulk, sealant, and water-stops at the seal joints of the walls and flood curbs. Degradation of the caulking, sealants, and water-stops in the auxiliary buildings is also managed by the Inspection Program. Inspection findings are evaluated to determine the appropriate corrective action that may include monitoring, repair, or replacement of caulk or sealant. The fire retardant sealant in the fire barriers are discussed in the fire protection program in Section 4.16 of Exhibit A of the LRA, and are evaluated in Section 3.2.4 of this report. The applicant stated that continued implementation of the inspection program provides reasonable assurance that caulking, sealants, and water-stops will be maintained to support the intended functions of the control room and auxiliary buildings for the period of extended operation.

The staff reviewed the applicant's response and found that caulking, sealants, and water-stops are included as parts of structural components that are within the scope of license renewal, and subject to an AMR under the inspection program or fire protection program. As a result of this review, the staff found the applicant's inclusion of caulking, sealants, and water stops as subcomponents acceptable. Therefore, Open Item 2.2.3.6.1.2.1-1 is closed.

2.2.3.6.1.2.2 Review Findings for Auxiliary Building

The staff has reviewed the information presented in Section 2.7.3 of Exhibit A of the LRA, the ONS UFSAR, and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff finds no omissions by the applicant in scoping the SCs for license renewal. The staff's review also found that all the structures and structural components identified as being within the scope of license renewal were subject to an AMR. Therefore, the staff concludes that there is reasonable assurance that the applicant has properly identified those structures and structural components associated with the auxiliary building group that are within the scope and subject to an AMR for license renewal, in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2.3.6.2 Earthen Embankments

In Section 2.7.4, "Earthen Embankments," of Exhibit A of the LRA, the applicant identified the SSCs of the earth embankments that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the earth embankment SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.2.1 Summary of Technical Information in the Application

As described in Section 2.7.4 of Exhibit A of the LRA, the earthen embankments consist of the intake canal dike, Keowee River dam, Little River dam and dikes A, B, C, and D that are partially or totally submerged in Lake Keowee. The intake canal dike is a homogenous embankment construction with rolled earth-fill. The dike has zoned filter drainage blankets under the downstream slope to collect and control seepage. The up-stream face is rip-rapped with dumped rip-rap and quarry run stone to accommodate all reservoir water levels. The intake canal dike is a Class 2 structure that is designed to withstand seismic loads and control erosion.

Structures and Components Subject to an Aging Management Review

The Keowee River dam is a homogenous embankment construction with rolled earth-fill. The dam embankment has seepage monitoring weirs and pipes, observation wells, and piezometers that monitor the dam performance. Slope protection from wind-generated waves was provided on the upstream slope of the dam and stone rip-rap was provided to accommodate all reservoir levels, including maximum draw-down and maximum flood. Ground cover is provided to control erosion. The Keowee River dam is a Class 2 structure and its design was approved by the Federal Energy Regulatory Commission (FERC) in accordance with the license issued by that agency.

The Little River dam and dikes A, B, C, and D, which impound the Little River watershed of the Keowee reservoir, are of a homogeneous embankment construction with rolled earth-fill. The dam and dikes are Class 2 structures and their designs were approved by the FERC in accordance with the license issued by that agency. The design and construction of the dam and dikes are similar to that of Keowee River Dam as described above.

2.2.3.6.2.2 Staff Evaluation

The staff reviewed Section 2.7.4 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the earthen embankments have been properly identified as being 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(a)(1).

2.2.3.6.2.2.1 Earthen Embankment Within the scope of License Renewal and Subject to an Aging Management Review

The basic earthen embankment is a mass earth work of soil fill designed to retain water. As shown in Table 2.7-2 of Exhibit A of the LRA, the intake canal dike, Keowee River dam, and Little River dam and dikes A, B, C and D are listed as the structures of the earthen embankments. These structures are within the scope of license renewal because they perform both of the following intended functions, as noted in the table:

- provide source of cooling water for plant shutdown, and
- impound water of Lake Keowee for generation at the Keowee hydroelectric power station. .

The staff reviewed the information presented in Section 2.7.4 of Exhibit A of the LRA and reviewed the discussion of the structures in UFSAR Sections 2.5.6 and 3.8.5 and the ONS Site Plan (flow diagram No. OLR-1), to determine if the listed structures are part of the earthen embankments or whether other similar structures having the earthen embankments' intended functions are not included in the scope of license renewal. As a result of this review, the staff found no omissions of structures by the applicant. However, the applicant listed the earthen embankment structures in Table 2.7-2 but did not list their associated components, such as weirs, pipes, observation wells, and piezometers. Upon further review, the staff finds the applicant's decision not to include components such as weirs, pipes, observation wells, and piezometers in Table 2.7-2 of Exhibit A of the LRA acceptable because these components monitor the dams' and dikes' performance and do not support the intended functions of the earthen embankments. The structures within the earthen embankments are subject to an AMR because its intended functions are performed without moving parts, or without a change in configuration or properties, and are not subject to replacement based on qualified life or specified time period. Therefore, the staff has reasonable assurance that the applicant has properly identified the earthen embankment structures that are within the scope of license renewal and subject to an AMR.

2.2.3.6.2.2.2 Review Findings for Earthen Embankments

The staff has reviewed the information in Section 2.7.4 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.3 Intake Structure

In Section 2.7.5, "Intake Structure," of Exhibit A of the LRA, the applicant identified the SSCs of the intake structure that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the intake structure SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.3.1 Summary of Technical Information in the Application

The intake structure, located at the north end of the intake canal, houses the CCW pumps and supports the pump motors and portions of the condenser cooling water piping. The intake structure is constructed primarily of reinforced concrete without a steel superstructure. The steel trash racks and screens at the entrance of the intake structure protect the condensers from foreign material present in the lake water. The reinforced concrete utility trench attached to the back of the intake structure protects the electrical cables to the intake structure. The intake structure and the utility trench are Class 2 structures that are designed to withstand a safe-shutdown earthquake.

In Table 2.7-3 of Exhibit A to the LRA, the applicant identified 17 structural components, such as foundation, slab, wall, cable tray, equipment supports, trash rack and screens. These components are within the scope of license renewal because they contribute to at least one of the following intake structure intended functions, as noted in the table:

- provide structural and/or functional support to safety-related equipment,
- provide shelter/protection to safety-related equipment, and

- provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions.

During the process to determine which components within the scope of license renewal are subject to an AMR, the applicant combined the 17 structural components into three general categories based on their design and materials: (1) concrete, (2) steel in air environment, and (3) steel in fluid environment. The steel components within the intake structure are either exposed to the external atmospheric environment or to lake water. The carbon steel trash racks, screens, and equipment component supports are the structural steel components that are exposed to lake water.

2.2.3.6.3.2 Staff Evaluation

The staff reviewed Section 2.7.5 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the intake structure have been properly identified as being 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(a)(1).

2.2.3.6.3.2.1 Intake Structure within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information provided in Section 2.7.5 and Table 2.7-3 of Exhibit A of the LRA and found that certain items for the intake structure were not clearly addressed. Specifically, components such as steel beams, columns, and trusses, indicated to the staff that the intake had a steel superstructure, when in reality it does not. The staff questioned the applicant about this approach in a May 27, 1999, conference call. The applicant's response, which is documented in a phone call summary dated June 2, 1999, was that the intake structure has no steel superstructure. The applicant stated that for the purposes of Table 2.7-3, miscellaneous steel components were included under the commodity group "steel beams, columns, plates, and trusses." In addition, the applicant stated that the components within the intake structure that fall within this commodity group are miscellaneous steel plates and other steel sections for guides for the trash racks and screens. Based on how the applicant categorized the items in Table 2.7-3, the staff agrees that this issue is resolved.

The ONS intake underwater weir is not described in Section 2.7.5 of Exhibit A of the LRA and was found not to be within the scope of license renewal. This submerged weir at the CCW pump suction has the intended function of retaining an emergency water supply in the event of a failure of the dam or dike that results in loss of the normal water supply. The staff discussed this issue with the applicant during the scoping inspection that occurred from April 26 through April 30, 199. The staff asked why the underwater weir was excluded from the scope of license renewal. The applicant provided the staff with documentation that provides the basis for not including the weir within the scope of license renewal. Specifically, the applicant referred the staff to Section 3.3.4 of the "Safety Evaluation by the Directorate of Licensing, USAEC, In the Matter of Oconee Nuclear Power Station, Units 2 and 3," dated July 6, 1973. The applicant also referred the staff to an inspection report dated May 31, 1995, and UFSAR Section 9.2.2.2.1. The applicant concluded that the underwater weir is not within the scope of license renewal based on the analysis performed in 1995 for a postulated loss of Lake Keowee event. The analysis indicated that the licensing basis does not rely on the underwater weir nor recirculation of the intake canal water for decay heat removal after a loss of Lake Keowee event. Based on the above documentation, the staff agrees with the applicant's determination that the underwater weir is not within the scope of license renewal.

As a result of the above review, the staff found no omissions in the SSCs of the intake structure that were included within the scope of license renewal as defined in 10 CFR 54.4(a). The staff also found no omissions in the structures and components of the intake structure included in the applicant's AMR that perform its intended function(s) without moving parts or without a change in configuration or properties, or that are not replaced based on a qualified life or specified time period, as required under 10 CFR 54.21(a)(1).

2.2.3.6.3.2.2 Review Findings for Intake Structure

The staff has reviewed the information presented in Section 2.7.5 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.4 Keowee Structures

In Section 2.7.6, "Keowee Structures," of Exhibit A of the LRA, the applicant identified the SSCs of the Keowee structures that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the Keowee structure SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.4.1 Summary of Technical Information in the Application

As described in Section 2.7.6 of Exhibit A to the LRA, the Keowee structures consist of a breaker vault, intake structure, power and penstock tunnels, powerhouse, service bay structure, and spillway. These Keowee structures are Class 2 structures. The Keowee breaker vault houses generator output breakers and protects the electrical equipment used to route power for plant emergency power needs. The vault structure is located on the operating floor of the powerhouse and its structural components, such as walls, roof, and access openings, are designed to withstand tornado and missile forces.

Structures and Components Subject to an Aging Management Review

The Keowee intake structure controls flow from Lake Keowee to the Keowee hydroelectric station turbines via the power and penstock tunnels. The Keowee intake structure is a reinforced concrete structure with eight sides. Each side has a pier connected to a reinforced concrete compression ring girder at the base to support a concrete silo type structure on top. The concrete silo structure supports a structural steel frame, which in turn provides support for the gate hoisting machinery. The water intakes between the eight piers can be closed individually by closing a steel buck-head gate between two piers. Alternatively, all eight intake openings can be closed by a large cylindrical gate inside the structure. The cylindrical gate is normally lowered inside the structure to a closed position and can be rigidly fastened to the steel superstructure with wire cables to an open position when the Keowee generating units are in operation for emergency power.

The Keowee power and penstock tunnels convey water from the intake structure in Lake Keowee to the Keowee hydroelectric station turbines in the Keowee powerhouse. The power tunnel connects the intake structure and the two penstocks that are branched from the power tunnel to each unit. The power tunnel and one-half of the penstock downstream of the power house are reinforced concrete structures. The downstream part of the penstock is steel lined with a concrete envelope around the steel lining. The power and penstock tunnels are built on excavated rock.

The Keowee powerhouse provides support and protection for the equipment and components used to generate emergency electrical power for ONS. The substructure of the powerhouse is a monolithic mass concrete construction on rock up to the operating floor level which supports a steel frame superstructure. The concrete substructure supports two vertical Francis-type turbines and contains a draft tube gallery, a scroll case access gallery, and a mechanical equipment gallery. The steel frame superstructure, which is covered with insulated steel panels, provides protection for the generator, a 270-ton bridge crane, and the associated electrical and mechanical equipment. A bay adjacent to the power house provides protection for the electrical switchgear and bus.

The Keowee service bay structure, located adjacent to the powerhouse structure, has two floor levels; one floor supports the station batteries and the other supports the Keowee control room, cable room, and equipment room. The service bay structure is a reinforced concrete structure built on rock.

The Keowee spillway controls the discharge of storm inflow from rainfall on the Lake Keowee drainage basin and prevents overtopping of the Keowee River dam, the Little River dam and dikes, and the ONS intake canal dike during periods of high rainfall on the drainage basin. The spillway is a mass concrete ogee-shaped structure with four taintor gates. Below the ogee section is a tapered concrete chute section with mass concrete side walls and a concrete flip bucket. The spillway is built on rock and the mass concrete wing-walls form an approach channel to the spillway. The taintor gates are constructed of a steel plate over a system of structural shapes that are supported on concrete piers between the gates. The piers also provide support for a bridge across the top of the structure that is used for inspection and maintenance of the structure and hoisting equipment.

Within these Keowee structures, the applicant identified 29 structural components and grouped them into three general categories; (1) concrete, (2) steel in air environment, and (3) steel in fluid environment. The 29 structural components, which are listed in Table 2.7-4 of Exhibit A to the LRA, are within the scope of license renewal because they perform one or more of the following intended functions, as noted in the table:

- provide structural and/or functional support to safety-related equipment,
- provide shelter/protection to safety-related equipment,
- serve as a missile barrier, and
- provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions.

The 29 structural components identified as being within the scope of license renewal were determined to be passive and not periodically replaced, and therefore, subject to an AMR.

2.2.3.6.4.2 Staff Evaluation

The staff reviewed Section 2.7.6 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the Keowee structures have been properly identified as being 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(a)(1).

2.2.3.6.4.2.1 Keowee Structures Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information in Section 2.7.6 of Exhibit A of the LRA to determine if the applicant properly identified all the structures and structural components of the Keowee facility as being within the scope of license renewal that meet the scoping criteria under 10 CFR 54.4(a). In Exhibit A of the LRA, the applicant has identified that the breaker vault, intake structure, power and penstock tunnels, powerhouse, service bay structure, and spillway at the Keowee site were within the scope of license renewal. The staff reviewed the information presented in Section 2.7.6 of Exhibit A of the LRA, the site plan (drawing OLR-1), and the UFSAR, Section 3.8.5, to determine if all the structures and structural components of the Keowee facility have been included within the scope of the rule and subject to an AMR, consistent with 10 CFR 54.4 and 54.21(a)(1). Based on that review, the staff questioned two areas associated with its review of Section 2.7.6 of Exhibit A of the LRA.

In RAI 3.7.6-3, the staff asked the applicant to explain why the roof slabs, listed in Table 2.7-4 of Exhibit A of the LRA, were identified as concrete components. In its response to this RAI, the applicant stated that the Keowee structures do not have any concrete roof slabs. The Keowee structures have a built-up roofing system. However, a reference to roof slabs in Table 2.7-4 needed additional clarification. The staff asked the applicant about the roof slabs in a May 27, 1999, phone call, and documented the discussions in a June 2, 1999, summary.

The applicant stated that the Keowee structures use both reinforced concrete roof slabs and built-up roofing systems. The Keowee breaker vault that is located within the powerhouse has a reinforced concrete roof slab. The main structures, such as the Keowee powerhouse and the service bay structure, have built-up roofing systems. The built-up roof systems are comprised of a metal roof deck, covered with rigid insulation and rubberized material. The applicant stated that this roof system is a short-lived component and is subject to periodic replacement based on its service condition. Therefore, the applicant did not include the built-up roof system in Table 2.7-4, and did not consider it subject to an AMR. However, neither the rule nor the Commission guidance provided in the Statements of Consideration (SOC), allows the generic exclusion of SCs based on performance or condition monitoring. An applicant may exclude SCs that are replaced on the basis of specific performance or condition monitoring activities from an AMR only if the following two conditions are met: 1) that the applicant identifies those SCs in the LRA that are being excluded based on performance and condition monitoring, and 2) that the applicant submit a site-specific justification for the exclusion of these components. This issue was identified as Open Item 2.2.3.6.4.2.1-1.

In its response of October 15, 1999 to Open Item 2.2.3.6.4.2.1-1, the applicant stated that rather than generally excluding the roof based on performance or condition monitoring, the built-up roof system has been re-evaluated based on function to determine whether an AMR is required. Upon further investigation, the applicant has determined that the roof system of the Keowee powerhouse is not subject to AMR because it does not perform an intended function required by 10 CFR 54.4. The powerhouse is within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). The roof is a component of the powerhouse, but it is not needed for the powerhouse to perform its intended function. Degradation or loss of the powerhouse roof will not result in loss of any structural, mechanical, or electrical system or component intended functions.

Table 2.7-4 of Exhibit A of the LRA identifies those components that perform the intended function of shelter or protection of safety-related equipment. The breaker vault is constructed of reinforced concrete walls, floor and roof slabs that protect the breakers. The electrical equipment is protected by the switchgear cabinets. The switchgear cabinets are included within the electrical panels and enclosures. The applicant stated that degradation of the powerhouse roof would not result in the loss of any component intended function. As a result, the roof of the powerhouse does not require an AMR, and is not listed in Table 2.7-4 of the LRA. The staff has reviewed the applicant's response and concludes that the applicant's justification for not including the powerhouse roof in the scope of license renewal is acceptable because it does not perform any function required by 10 CFR 54.4(a). In addition, because the roof system is not subject to an AMR, a site-specific justification for its exclusion is not required. Therefore, Open Item 2.2.3.6.4.2.1-1 is closed.

Section 2.7.6.4 described the function of the electrical switchgear bay but did not describe its structure and components or whether they are subject to an AMR. The staff asked the applicant about the switchgear structures in a May 27, 1999, phone call, and documented the phone call in a June 2, 1999, summary.

The applicant stated that the switchgear bay is part of the Keowee powerhouse located on the operating floor. The switchgear bay is the adjacent area where the switchgear are located. As part of the powerhouse, the applicant considers this area to be subject to an AMR. The staff finds the applicant's response acceptable.

The staff has reasonable assurance that the applicant has properly identified those SCs associated with the Keowee structure which perform the intended functions as defined in 10 CFR 54.4, and has properly identified these SCs as being within the scope of license renewal.

As a result of the above review, the staff found no omissions in the SSCs of the Keowee structures that were included within the scope of license renewal as defined under 10 CFR 54.4(a). The staff also found no omissions in the structures and components of the Keowee structures included in the applicant's AMR that perform its intended function(s) without moving parts or without a change in configuration or properties, or that are not replaced based on a qualified life or specified time period, as required under 10 CFR 54.21(a)(1).

2.2.3.6.4.2.2 Review Findings for Keowee Structures

The staff has reviewed the information presented in Section 2.7.6 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.5 Reactor Buildings Internal Structure and the Unit Vent Stacks

In Section 2.7.7, "Reactor Buildings Internal Structure and the Unit Vent Stacks," of Exhibit A of the LRA, the applicant identified the SSCs of the reactor buildings internal structure and unit vent stacks that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the reactor building internal structure and unit vent stack SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.5.1 Summary of Technical Information in the Application

As described in Section 2.7.7 of Exhibit A to the LRA, the reactor building internal structures consist of: (1) the reactor cavity, (2) two steam generator compartments, and (3) a refueling canal which is located between the steam generator compartments and above the reactor cavity in each of the reactor buildings. The reactor cavity, which serves as the primary shield wall, houses the reactor vessel and was designed for core flooding water pressure up to the level of the reactor nozzle. Each of the two steam generator compartments serves as a secondary shield wall which house the steam generator, reactor coolant pump, and associated RCS piping. The pressurizer and quench tank are located in one of the steam generator compartments. The unit vent stack is a vertical steel cylindrical stack used to release gaseous discharge. The reactor cavity has six openings that are missile protected and used for venting purposes. The steam generator compartments are designed so that the secondary shield walls can be removed. The removable sections of the secondary shield walls are post-tensioning reinforced concrete structures which are designed as horizontal post-tensioned prestressed and vertical steel reinforced concrete structures. The remaining portions of the secondary shield walls are reinforced concrete structures. The post-tensioning reinforced concrete components that are subject to an AMR are grouped as the post-tensioning system. Lateral supports are provided for the steam generator that are attached to the secondary shield wall. There are structural steel platforms, ladders and grating in each of the compartments for access to various elevations of the compartment for inspection and maintenance. The reactor building internal steel structures are also designed to support the safety related components, such as the core flood tanks, reactor building cooling units, Emergency Core Cooling System piping, and electrical instrumentation, control, and power. The reactor building internal structures are Class 1 structures that are designed to withstand all loadings without loss of function and prevent uncontrolled release of radioactivity, and therefore, meet 10 CFR 54.4(a)(1).

The applicant identified and listed 28 structural component types in Table 2.7-5 of Exhibit A to the LRA. These components are further grouped into four categories based on their materials and function: (1) concrete, (2) steel in air environment, (3) steel in fluid environment, and (4) miscellaneous. The miscellaneous category includes the post-tensioning system which is unique to the steam generator compartments. These 28 structural components are within the scope of license renewal because they perform one or more of the following intended functions, as noted in the table:

- provide pressure boundary and/or fission product barrier
- provide structural and/or functional support to safety-related equipment
- provide shelter/protection to safety-related equipment (including radiation shielding)
- serve as a missile (internal or external) barrier
- provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions
- provide a protective barrier for an internal/external flood event
- provide path for release of filtered and unfiltered gaseous discharge
- provide heat sink during station black out (SBO) or design-basis accidents

The 28 structural components identified above were determined by the applicant to be subject to an AMR because its intended functions are performed without moving parts or without a change in configuration or properties and these SCs are not subject to replacement based on qualified life or specified time period as specified under 10 CFR 54.21(a)(1).

2.2.3.6.5.2 Staff Evaluation

The staff reviewed Section 2.7.7 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the reactor building internal structure and unit vent stacks have been properly identified as being 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(a)(1).

2.2.3.6.5.2.1 Reactor Building Internal Structure and Unit Vent Stacks Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information presented in Section 2.7.7 of Exhibit A of the LRA, a portion of UFSAR Chapter 3.8, and the floor plan drawings in UFSAR Chapter 1, to determine if there were any structures, portions of structures, and components associated with the reactor building internal structure and unit vent stacks that the applicant did not properly identify as being within the scope of license renewal or did not properly identify as being subject to an AMR. The staff reviewed each of the 28 components listed in Table 2.7-5 of Exhibit A of the LRA to determine if they are part of the components within the reactor buildings. The staff also verified, with the UFSAR and applicable drawings, that there were no other reactor building components that were not included within the scope of license renewal that perform the reactor building intended functions.

As a result of the above review, the staff found no omissions in the SSCs included within the scope of license renewal as defined under 10 CFR 54.4(a). The staff also found no omissions in the SCs of the Reactor Building internal structure and unit vent stacks identified by the applicant as requiring an AMR.

2.2.3.6.5.2.2 Review Findings for Reactor Buildings Internal Structure and Unit Vent Stacks

The staff has reviewed the information presented in Section 2.7.7of Exhibit A of the LRA, and the ONS UFSAR. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.6 Standby Shutdown Facility

In Section 2.7.8, "Standby Shutdown Facility," of Exhibit A of the LRA, the applicant identified the SSCs of the standby shutdown facility (SSF) that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the SSF SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

Structures and Components Subject to an Aging Management Review

2.2.3.6.6.1 Summary of Technical Information in the Application

The SSF is a reinforced concrete structure that houses the standby shutdown systems used to achieve and maintain safe-shutdown conditions from outside of the control room in the event of a postulated fire, sabotage, or flooding event. The SSF is a Class 1 structure that must remain functional after a safe-shutdown earthquake. The applicant identified and listed 25 structural components in Table 2.7-6 of Exhibit A of the LRA and grouped them into two generic categories: (1) the concrete components, including reinforced concrete beams, columns, walls, floor and roof slabs, foundation, hatches, equipment pad, flood curbs and anchorage, and (2) the steel components, including battery racks, cable tray and conduits and their supports, control room ceiling, control boards, instrument panels and enclosures, flood and pressure doors, equipment component supports, HVAC ducts, instrument lines, pipe supports, crane rails and girders, and stairs, platforms and gratings supports. These 25 structural components are within the scope of license renewal because they perform at least one of the following intended functions, as noted in the table:

- provide structural and/or functional support to safety-related equipment
- provide shelter/protection to safety-related or non-safety related equipment
- provide structural and/or functional support to non-safety-related equipment where failure of this structural component could directly prevent satisfactory accomplishment of any of the safe shutdown functions
- serve as missile a (internal or external) barrier
- provide a protective barrier for an internal/external flood event

These 25 structural components within the scope of license renewal, are subject to an AMR because the intended functions are performed without moving parts or without a change in configuration or properties, and are not subject replacement based on qualified life or specified time period.

2.2.3.6.6.2 Staff Evaluation

The staff reviewed Section 2.7.8 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the SSF have been properly identified as being 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(a)(1).

2.2.3.6.6.2.1 Standby Shutdown Facility Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information presented in Section 2.7.8 and Table 2.7-6 of Exhibit A of the LRA, supporting information in the UFSAR, and the applicant's response to the staff's question concerning water stops and structural sealants for the Standby Shutdown Facility (SSF) water-tight building to determine if all the structures and structural components have been included within the scope of the rule and subject to an AMR consistent with the requirements of 10 CFR 54.4 and 54.21(a)(1). The staff reviewed the 25 structures and structural components and their intended functions listed in Table 2.7-6.

In Section 2.2.3.6.1 of this report, the staff discusses the inclusion of expansion joints, caulking, structural sealants, and water stops within the scope of license renewal and subject to an AMR. This discussion also applies to expansion joints, caulking, structural sealants, and water stops associated with the SSF because this structure was designed to be water tight under all design-basis events. Section 2.2.3.6.1 identifies and addresses the generic need for the applicant to include expansion joints, caulking, structural sealants, and water stops within the scope of license renewal and subject to an AMR when applicable under 10 CFR 54.4 and 54.21(a)(1). As discussed in Section 2.2.3.6.1, the applicant did include expansion joints, caulking, structural sealants, and water stops as subcomponents for all applicable structures and structural components including the SSF.

In its response to Open Item 2.2.3.6.1.2.1-1, dated October 15, 1999, the applicant stated that materials, such as caulking, sealants, and water stops, are not considered as individual structures or components. However, these materials are important in maintaining the integrity of the components to which they are connected. The applicant has identified the inspection program for Civil Engineering Structures and Components as the program used to manage the aging of these subcomponents. The implementation of this program has identified instances where degradation of these materials have resulted in discoloration of the concrete and leaching in the SSF building, and have resulted in the implementation of corrective actions. Discoloration and leaching along the expansion joints with water stops also have been identified. The expansion joint has been sealed on the inside surface of the concrete. The applicant stated that continued implementation of the inspection program for Civil Engineering Structures and Components provides reasonable assurance that the caulking, sealants, and water stops can support the intended functions of the SSF building. The staff has previously reviewed the applicant's rationale for Open Item 2.2.3.6.1.2.1-1 and found it acceptable for the auxiliary building, as addressed in Section 2.2.3.6.1.2.1 of this report. Based on the same rationale, the staff finds that including caulking, sealants, and water stops within the scope of the rule and subject to an AMR as subcomponents is acceptable for the SSF.

2.2.3.6.6.2.2 Review Finding for Standby Shutdown Facility

The staff has reviewed the information presented in Section 2.7.8 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.7 Turbine Building

In Section 2.7.9, "Turbine Building," of Exhibit A of the LRA, the applicant identified the SSCs of the turbine building that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the turbine building SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.7.1 Summary of Technical Information in the Application

In Section 2.7.9 of Exhibit A of the LRA, the applicant identified the turbine building as being within the scope of license renewal. For the purpose of license renewal, the applicant defined the following structures as being part of the turbine buildings: the turbine buildings, Units 1 and 2 transformer and switchgear enclosure, and Unit 3 switchgear enclosure. The turbine building is a large steel frame structure which houses the turbine generators and its associated components and equipment for all three units without partitions between each unit. The turbine buildings are constructed with a reinforced concrete substructure and a steel frame superstructure. The substructure consists of a reinforced concrete mat foundation and walls that are below grade. The superstructure, which is above grade, is a structural steel building with metal sidings. The turbine building is a Class 2 structure. Class 2 structures are those whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown, but could interrupt power generation. Duke determined Class 2 structures meet the intent of 10 CFR 54.4(a)(2).

The Units 1 and 2 transformer (CT4) and switchgear (4kV) enclosure and the Unit 3 switchgear (4kV) enclosure are Class 1 structures that must remain functional after a safe-shutdown earthquake. The Units 1 and 2 transformer and switchgear enclosure is a reinforced concrete structure with penetrations on the walls for the electrical bus, ventilation, and personnel access. The enclosure is divided into two separate rooms by a masonry block firewall. Ventilation for transformer CT4 and its enclosure is provided by fans on the east wall and 12 penetrations through the North and South walls. The Unit 3 switchgear enclosure is a reinforced concrete structure supported by battered-pipe piles filled with concrete. Ventilation for this enclosure is provided by fans on the West wall. The ventilation penetrations and personnel access doors for all these enclosures are missile protected. The transformers and electrical buses are seismically braced with structural steel.

The applicant listed 29 generic structural components within the turbine building, and identified their intended functions in Table 2.7-7 of Exhibit A to the LRA. The 29 structural components are grouped into three categories based on their materials and function: (1) concrete, (2) steel in air environment, and (3) fire barriers. These 29 components are within the scope of license renewal because they perform one or more of the following intended functions, as noted in the table:

- provide structural and/or functional support to safety-related equipment,

- provide structural and/or functional support to non-safety-related equipment whose failure could directly prevent satisfactory accomplishment of any of the required safety-related functions,
- provide shelter/protection to safety-related equipment (including radiation shielding),
- provide rated fire barrier to confine or retard a fire from spreading,
- serve as missile barrier, and
- provide a protective barrier for internal/external flood event.

These 29 structural components within the scope of license renewal, are subject to an AMR because the intended functions are performed without moving parts or without a change in configuration or properties, and are not subject replacement based on qualified life or specified time period.

2.2.3.6.7.2 Staff Evaluation

The staff reviewed Section 2.7.9 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the turbine building structures and structural components have been properly identified as being 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(a)(1).

2.2.3.6.7.2.1 Turbine Building Within the scope of License Renewal and Subject to an Aging Management Review

The staff reviewed the information submitted in Section 2.7.9 of Exhibit A of the LRA, the structural components listed in Table 2.7-7 of Exhibit A of the LRA, and portions of Chapter 3 of the UFSAR to determine if there were any portions of the structures and associated components that the applicant did not identify as within the scope of license renewal or subject to an AMR.

In Exhibit A of the LRA, Table 2.7-7, the applicant lists roof slabs as concrete components. The staff's review found that the turbine building has a steel frame superstructure with a composite roof system (not concrete roof slabs) built on top of roof trusses. Furthermore, the turbine building roof supports the pull-off structures of the transmission lines. These special devices were not described and the applicable components were not listed in Exhibit A, Table 2.7-7. The staff asked the applicant about the roof slabs and the pull-off structures of the transmission lines in a May 27, 1999, phone call, and documented these discussions in a June 2, 1999, summary.

The applicant stated in the May 27, 1999, phone call that the switchgear enclosures adjacent to the turbine building are reinforced concrete structures with reinforced concrete roof slabs that were listed in Table 2.7-7 of Exhibit A of the LRA. The turbine building has a composite roof system, which is comprised of a metal roof deck, covered with rigid insulation, bitumen, inorganic felts and a cover layer of aggregate. This composite roof system is a short-lived component and is subject to periodic replacement based on performance and condition.

Therefore, the applicant determined that the composite roof system was within the scope of license renewal but not subject to an AMR and did not listed the applicable components in Table 2.7-7.

However, as discussed in Subsection 2.2.3.6.4.2.1 of this report, neither the rule nor the Commission guidance provided in the SOC, allows for the generic exclusion of SCs based on performance or condition monitoring. An applicant may exclude a structure and component from an AMR on the basis of performance or condition monitoring activities only if the following two conditions are met: 1) the applicant identifies those SCs in the LRA that are being excluded based on performance and condition monitoring, and 2) the applicant submit a site-specific justification for the exclusion of these components. This item was addressed in Open Item 2.2.3.6.4.2.1-1.

In its October 15, 1999, response to Open Item 2.2.3.6.4.2.1-1, the applicant re-evaluated the roof systems for the Keowee powerhouse and turbine building to determine whether they are subject to an AMR. On the basis of its evaluation, the applicant determined that the turbine building roof system was not subject to AMR because it does not meet the scoping criteria under 10 CFR 54.4, and should not have been included within the scope of license renewal. The applicant stated that degradation or loss of the turbine building roof will not result in the loss of any structural, mechanical, or electrical system or component function. The turbine building contains safety-related SSCs in the basement, which would remain sheltered and protected by several reinforced concrete floors if the turbine building roof was to degrade. Since the roof does not perform an intended function within the scope of license renewal, the roof system is not listed in Table 2.7-7 of Exhibit A of the LRA and is not within the scope of license renewal.

The staff reviewed the applicant's response for excluding the roof system of the turbine building from within the scope of license renewal and found it's rationale acceptable. The roof system of the turbine building does not meet any of the scoping criteria of 10 CFR 54.4(a) and is not within the scope of license renewal. Because the roof system is not within the scope of the rule, it need not be considered under 10 CFR 54.21(a)(1) for an AMR.

The applicant also stated in the May 27, 1999, phone call that the shield wire pull-off structures, which are described in Section 2.7.10.6 of Exhibit A of the LRA, are A-frame towers similar to the strain structures in the 230 kV switchyard. These structures are constructed of hot-dipped galvanized steel with welded and bolted connections. The shield wire pull-off structures are included in the yard structures in Subsection 2.7.10.6 of Exhibit A of the LRA under transmission towers because of its similar function and construction materials. The transmission towers were listed in Table 2.7-8 and 3.7-8 of Exhibit A of the LRA. The shield wire pull-off structures are subject to an AMR. The staff found the applicant's response for the roof slabs and the shield wire pull-off structure to be acceptable.

As a result of the above review, the staff found no omissions in the SSCs of the Turbine Building that were included within the scope of license renewal as defined under 10 CFR 54.4(a). The staff also found no omissions in the structures and components of the Turbine Building included in the applicant's AMR that perform its intended function(s) without moving parts or without a change in configuration or properties, or that are not replaced based on a qualified life or specified time period, as required under 10 CFR 54.21(a)(1).

2.2.3.6.7.2.2 Review Findings for Turbine Building

The staff has reviewed the information presented in Section 2.7.9 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.8 Yard Structures

In Section 2.7.10, "Yard Structures," of Exhibit A of the LRA, the applicant identified the SSCs of the yard structures that are within the scope of license renewal as required under 10 CFR 54.4. The applicant also identified and listed the yard structure SCs that are subject to an AMR as required under 10 CFR 54.21 (a)(1).

2.2.3.6.8.1 Summary of Technical Information in the Application

As described in Section 2.7.10 of Exhibit A of the LRA, the yard structures consist of a 230 kV relay house, 230 kV switchyard structures, trenches, 230 kV towers from Keowee to the ONS, an elevated water storage tank, transformer pads for transformers CT1, CT2, CT3, and Keowee transformer 1, and the foundations and pipe supports located in the yard.

The 230 kV switchyard relay house is a rectangular steel frame structure that houses and protects the 230 kV switchyard relay. It is erected on a reinforced concrete slab on grade. This relay house is a Class 2 structure that is designed to withstand design basis seismic loads.

The 230 kV switchyard structures are Class 2 structures that are designed to support or protect the electrical equipment and transmission lines in the 230 kV switchyard and the overhead power path. The applicant identified the following switchyard structures to be within the scope of license renewal and subject to an AMR:

- Bus support bases
- Coupling capacitor potential device support bases
- Disconnect switch supports
- Lightning arrestor supports
- Power circuit breaker bases
- Strain structures and bases
- Wave trap support structures

Structures and Components Subject to an Aging Management Review

The bus support bases are cylindrical reinforced concrete footings embedded in earth that support the electrical buswork support steels. The coupling capacitor potential device support bases, disconnect switch supports, lightning arrestor supports, and the wave trap supports are steel post supports built in a reinforced concrete base. The power circuit breaker bases that support certain power circuit breakers for the Keowee overhead power path are reinforced concrete footings embedded in the ground. The steel strain structures and their reinforced concrete foundations in the 230 kV switchyard and at the Keowee site are an integral part of the Keowee overhead power path.

The elevated water storage tank is a 100,000 gallon circular atmospheric tank that stores water for the High Pressure Service Water System. The circular shaft and conical bell of the tank are constructed of structural steel. The bell is attached to the foundation by anchors. Both the interior and exterior of the tank are coated for corrosion protection.

The Keowee main step-up transformer base is located southwest of the Keowee powerhouse. The transformer is supported on piers which are on top of a reinforced concrete base on soil. A structural steel frame attached to each pier is provided as the seismic restraint for the transformer. The ONS CT1, CT2, and CT3 startup transformer bases are located in the ONS transformer yard to the east of the turbine building. Reinforced concrete bases on soil are provided for each of the unit's startup transformers. The transformers are supported on top of the reinforced concrete base with piers. These bases are Class 2 structures.

There are external reinforced concrete trenches throughout the ONS yard to route underground cables and piping. Only the trenches that provide shelter and protection for the safety-related equipment are within the scope of license renewal. The applicant identified the following trenches that are subject to an AMR:

- Standby shutdown facility cable trench
- Emergency power path cable trench
- Intake structure cable trench
- Borated water storage tank pipe trench

The standby shutdown facility cable trench carries electrical cables from the standby shutdown facility to each unit's auxiliary building. This cable trench is a Class 2 structure that is designed for missile, seismic, and truck loads. The emergency power path cable trench is a precast, reinforced concrete structure that is laid out on a grid pattern to cover the entire 230 kV switchyard. This cable trench is a Class 2 structure. The intake structure cable trench is a reinforced concrete trench with a checkered plate cover. The cable trench to the intake structure is a Class 2 structure. The borated water storage tank pipe trench is a reinforced concrete structure located between the auxiliary building and the borated water storage tank foundation such that the foundation of the auxiliary building forms the east side trench wall. The borated water storage tank pipe trench is a Class 1 structure. All of the trenches are covered with reinforced concrete panels except the intake structure cable trench.

The 230 kV Keowee transmission line, which provides the overhead power path from the 230 kV switchyard in the Keowee site to the ONS site, is supported by two dead-end type lattice towers and one suspension lattice tower. These three lattice towers are Class 2 steel structures that meet the requirements of the National Electric Code (NEC) for heavy loading Grade B construction and their components are seismically designed. The shield wire pull-off structures located on the roof of the turbine building support the loads of the transmission lines. The transmission towers are constructed of hot-dipped galvanized steel with welded and bolted connections. The applicant identified these structures as within the scope of license renewal and subject to an AMR.

2.2.3.6.8.2 Staff Evaluation

The staff reviewed Section 2.7.10 of Exhibit A of the LRA and the ONS UFSAR to determine if the applicant has adequately implemented its methodologies such that there is reasonable assurance that the structures and structural components comprising the yard structures have been properly identified as being 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(a)(1).

2.2.3.6.8.2.1 Yard Structures Within the scope of License Renewal and Subject to an Aging Management Review

The applicant identified the 230 kV relay house, 230 kV switchyard structures, certain cable and pipe trenches, transmission towers, elevated water storage tank, transformer pads, and pipe supports for transformers CT1, CT2, CT3, and the Keowee transformer, as being within the scope of license renewal. The staff agrees that these structural components are within the scope of license renewal because they perform either or both of the two yard structures intended functions: (1) provide structural and/or functional support to safety-related or non-safety related equipment, and (2) provide shelter/protection to safety-related equipment. Within the yard structures, the applicant listed 22 structural components and identified their intended functions in Table 2.7-8 of Exhibit A of the LRA. These 22 components are grouped into three categories: (1) concrete, (2) steel in air environment, and (3) steel in fluid environment. Other structural components that are part of the yard structures, but do not contribute to any of the intended functions of the yard structures are not included in the table. The components listed on Table 2.7-8 of Exhibit A of the LRA are subject to an AMR because the intended functions are performed without moving parts and without a change in configuration or properties, and are not subject to replacement based on qualified life or specified time period.

As a result of the above review, the staff found no omissions in the SSCs of the yard structures that were included within the scope of license renewal as defined under 10 CFR 54.4(a). The staff also found no omissions in the structures and components of the yard structure identified by the applicant as requiring an AMR.

2.2.3.6.8.2.2 Review Findings for Yard Structure

The staff has reviewed the information presented in Section 2.7.10 of Exhibit A of the LRA, the ONS UFSAR, and the applicant's response to the staff's RAIs. On the basis of this review, the staff has reasonable assurance that the applicant (1) has properly identified those SSCs within the scope of license renewal, as required by 10 CFR 54.4, and (2) has properly identified those SCs within the scope of license renewal which require an AMR, as required by 10 CFR 54.21(a)(1).

2.2.3.6.9 Pipe Supports

In Section 2.7.2, "Structural Components," of Exhibit A to the LRA, the applicant listed the concrete and steel structural components, including pipe supports, subject to an AMR. The applicant provided further details about which pipe supports are within the scope of license renewal and subject to an AMR in Section 2.7.2.2.1, "Pipe Supports," of Exhibit A of the LRA.

2.2.3.6.9.1 Summary of Technical Information Regarding Pipe Supports in the Application

At the ONS, piping is supported by different types of hangers and supports to satisfy the United States of America Standard (USAS) B31.1.0 and B31.7 code requirements. Piping supports are constructed of a standard support, a structural frame, or some combination of the two. Pipe supports are coated to prevent corrosion and loss of material.

The types of piping supports used at the ONS include:

- Single-acting rigid type supports
- Double-acting rigid type supports
- Constant support spring hangers
- Variable support spring hangers
- Anchors
- Guides and stops
- Restraints
- Snubbers

The applicant noted in Section 2.7.2.2.1 of Exhibit A of the LRA, that although snubbers themselves are excluded from an AMR by 10 CFR 54.21, the components that mount the snubber to the pipe and structure are subject to an AMR.

The applicant identified the pipe supports that are within the scope of license renewal using the system flow diagrams in OLRP-1002. Piping within the scope of license renewal is identified on these flow diagrams. The flow diagrams can be used to identify the associated math model that contains the pipe supports. All pipe supports within the license renewal evaluation boundary defined by the Oconee flow diagrams, including any overlap supports required by the seismic analysis math modeling, are within the scope of license renewal. The applicant identified the following groups of pipe supports within the scope of license renewal:

- Oconee Class A, B, C, and F piping supports
- Oconee Class D piping supports
- Oconee Classes E, G, and H pipe supports that are identified as Quality Assurance (QA) Condition 4
- Pipe supports that maintain piping required to meet any of the regulatory events defined in 10 CFR 54.4(a)(3).

The applicant inadvertently noted in the original application that pipe supports associated with Oconee Piping Class E are not within the scope of license renewal. The applicant corrected the list of piping classes within the scope of license renewal in a letter to the staff dated October 15, 1999, to include those Class E piping supports that are required for seismic structural integrity.

2.2.3.6.9.2 Staff Evaluation

The staff reviewed this section of the LRA to determine whether there is reasonable assurance that the pipe supports within the scope of license renewal and subject to an AMR have been identified by the applicant in accordance with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

2.2.3.6.9.2.1 Pipe Supports Subject to Aging Management Review

As part of the first step of its evaluation, the staff reviewed the information submitted by the applicant in the LRA to determine whether the applicant failed to identify systems, or portions of systems, that have pipe supports and that perform intended functions within the scope of license renewal. In Section 2.7.2.2.1 of Exhibit A of the LRA, the applicant stated that all pipe supports within the license renewal boundary, as defined by the flow diagrams in OLRP-1002, are within the scope of license renewal for Oconee Class A, B, C, D, and F piping. In addition, pipe supports associated with Oconee Class G and H piping assigned a QA Condition 4 and any piping required to meet any of the regulatory events defined in 10 CFR 54.4(a)(3) are also within the scope of license renewal, and identified as such on the flow diagrams in OLRP-1002. In a letter dated October 15, 1999, the applicant clarified the fact that pipe supports associated with Oconee Class E piping assigned a QA Condition 4, which had been inadvertently omitted from the LRA, were also included within the scope of license renewal.

In Section 2.2.3 of this SER, the staff reviewed the applicant's identification of those systems and structures at the ONS that were within the scope of license renewal and determined that there was reasonable assurance that the applicant had identified all of the systems and structures within the scope of license renewal. Sections 2.2.3.1 through 2.2.3.7 of this SER document the staff's review of the individual system and structure boundary evaluations to determine whether the applicant identified those portions of systems and structures within the scope of license renewal. Since the applicant includes all pipe supports within the license renewal boundary defined by the flow diagrams in OLRP-1002, and since the staff has reviewed and accepted the license renewal boundaries for the systems within the scope of license renewal, the staff has reasonable assurance that the applicant has identified all the pipe supports within the scope of license renewal.

Inasmuch as pipe supports are passive components and not subject to replacement on a periodic basis, they are subject to an AMR. Snubbers are specifically excluded from this group of components by 10 CFR 54.21(a)(1)(i) and have been appropriately identified by the applicant as not subject to an AMR. The staff reviewed Tables 2.7-1 through 2.7-8 and found pipe supports appropriately listed as components subject to an AMR, pursuant to 10 CFR 54.21, for each structure except earthen embankments (Table 2.7-2). Earthen embankments, which are reviewed in Section 2.2.3.6.2 of this SER, are dikes and dams made from rolled earthfill and do not have pipe supports performing intended functions as defined in 10 CFR 54.4.

Piping Segments that Provide Structural Support

Systems which have safety-related/non-safety-related (SR/NSR) transition points include a boundary valve or other flow controlling component (e.g., orifice) at the transition point. The structural integrity of the boundary point, which functions as system pressure boundary, must not be compromised. To ensure proper seismic structural support if the boundary component itself is not anchored, the system's structural boundary must be extended beyond the boundary component to the first seismic anchor (or equivalent) and include the pipe segment connecting the boundary component to the pipe support. The pipe segment and seismic anchor together act as a single support system ensuring the integrity of the SR/NSR functional boundary under all design basis conditions. Providing structural support under all CLB design loading conditions for safety-related components (within the scope of license renewal) is the only intended function for these piping segments and anchors.

Since all fluid systems containing safety-related piping are within the scope of license renewal, these systems potentially have SR/NSR functional boundaries where piping segments beyond the functional boundary could be credited with structural support of the boundary point. The applicant states in Section 2.7.2.2.1, that the flow diagrams in OLRP-1002 can be used to identify the associated math model that contains the pipe supports. However, the highlighted flow diagrams in OLRP-1002 do not show which pipe segments and pipe supports are credited with supporting the functional boundary components, and as such, the staff could not verify that the applicant had identified all pipe segments that are within the scope of license renewal and subject to AMR. This concern was documented as Confirmatory Item 2.2.3.6.9-1.

On June 2, 1999, the staff and the applicant held two conference calls to clarify the applicant's position on documenting pipe segments that provide structural support. In a memorandum dated June 2, 1999, the staff documented the conclusion from the conference calls. As documented in the June 2, 1999, memorandum, the applicant stated that all SR/NSR interface valves for Oconee piping classes B, C, and F included piping segments and anchorages beyond the SR/NSR interface boundary valve that ensured the integrity of the boundary valve under all design basis loadings. The applicant stated that these components were included within the scope of license renewal and subject to AMR. The applicant further clarified that Oconee piping class A does not interface with non-safety-related piping and, therefore, does not have any piping segments or anchorages that support SR/NSR boundary valves. Likewise, Oconee class D piping is NSR and is included within the scope of license renewal only to ensure its failure during a design-basis event does not affect the capability of adjacent safety-related equipment to perform its intended function. Therefore, class D piping included in the scope of license renewal for this reason will not have any SR/NSR interfaces requiring piping segments that provide structural support to boundary points. Likewise, Oconee piping Classes E, G, and H, which were included within the scope of license renewal, are not safety-related or seismically qualified, and therefore, will not have SR/NSR interfaces requiring piping segments that provide structural support to boundary points.

The applicant committed to document the information from the two conference calls regarding the status of piping segments that provide structural support to boundary points. In a letter dated October 15, 1999, the applicant provided the information necessary to close Confirmatory Item 2.2.3.6.9-1.

2.2.3.6.9.2.2 Review Findings for Pipe Supports

On the basis of this review the staff concludes that there is reasonable assurance that the applicant has identified and listed the pipe supports within the scope of license renewal and subject to an AMR, in accordance with 10 CFR 54.4 and 10 CFR 54.21.

2.2.3.6.10 Essential Siphon Vacuum Building and Trenches

In its LRA Amendment submittal of September 30, 1999, the applicant added essential siphon vacuum (ESV) building and trenches to its application for license renewal as a result of the plant modification (which was discussed in Section 2.2.3.4.9 of this report). This plant modification constitutes a change to the contents of the LRA, which was submitted in July 1998. In Section 1.2, "Structural Integrated Plant Assessment," of the LRA Amendment, the applicant described the ESV building and trench structures and listed their structural components that are within the scope, and subject to an AMR for license renewal.

2.2.3.6.10.1 Summary of Technical Information in the Application

The ESV building encloses the pumps, motors and associated equipment of the ESV System and provides a suitable environment (protected from weather) for maintenance activities. The ESV building is a single story, single span, pre-engineered rigid frame steel structure with metal sidings built on a reinforced concrete slab foundation. This pre-engineered ESV building and its foundation are Class 2 structures. Class 2 structures are those structures whose limited damage would not result in a release of radioactivity and would permit a controlled plant shutdown but could interrupt power generation. The applicant has determined that Class 2 structures meet the intent of 10 CFR 54.4(a)(2).

The essential siphon vacuum trenches, which include ESV System cable trench and ESV System intake dike trench, are designed for underground routing of cables and piping. The piping and cables associated with the ESV and SSW Systems are routed from the turbine building to the ESV building via the existing radwaste trench and the newly constructed ESV System cable trench. Routing of the ESV and SSW Systems piping, electrical heat trace cables, and electrical instrumentation cables from the ESV building to the intake structure is by way of embedded conduits and the newly constructed intake dike trench. The intake dike trench is constructed of reinforced concrete (bottom slab and walls) and covered with steel plate except at the roadway crossing. The covers at the roadway are the removable reinforced concrete slabs. The design and construction of the cable trench are similar to that of the intake dike trench. The ESV System cable and dike trenches are Class 2 structures.

The structural components of the ESV building and their intended functions are listed in Table 1-3 of the LRA Amendment. The applicant listed the anchorage and embedment in concrete, equipment pads, flood curbs, and foundation as the concrete components. The anchorage and embedment at exposed surfaces, expansion anchors, cable tray and conduit and their supports, checkered plate, electrical and instrument panels and their enclosures, instrument line and pipe supports, instrument racks and frames, louvers and vents, as well as the structural steel beams, columns, plates, and trusses are listed as the steel components in air environment. The applicant identified a total of 17 component types in the table that are within the scope of license renewal because they perform one or more of the following intended functions, as noted in the table:

- provides structural and/or functional support to safety-related equipment
- provides structural and/or functional support to non-safety related equipment where failure of this structural component could directly prevent satisfactory accomplishment of any of the required safety-related functions.
- provides shelter/protection to safety-related equipment
- provides a protective barrier for internal/external flood event

These components are subject to an AMR because the intended function(s) are performed without moving parts, or without a change in configuration or properties, and are not replaced based on qualified life or specified time period. The table does not list the components of the ESV trenches. However, because these trenches are similar in design and construction, the applicant determined that the ESV trenches are part of the trenches in the yard structures of Section 2.7.9 of Exhibit A of the LRA. Therefore, the ESV trenches are within the scope of license renewal, and are subject to an AMR. The staff's review of the group of trenches is provided in Section 2.2.3.6.8 of this report.

2.2.3.6.10.2 Staff Evaluation

The staff reviewed Section 1.2 of the LRA Amendment and the ONS UFSAR to determine if there is reasonable assurance that the SCs comprising the ESV building and trenches have been properly identified as being 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(a)(1).

2.2.3.6.10.2.1 Essential Siphon Vacuum Building and Trenches Within the scope of License Renewal and Subject to Aging Management Review

The staff has reviewed Section 1.2 of the LRA Amendment and the supporting information in Section 3.8.5.1 of the ONS UFSAR, design drawings Nos. 0-347-J-001 and -002 (for the ESV building), and the partial site plan (for the trenches) to determine if there were any structures or associated components within the ESV building and trenches that the applicant did not identify as being within the scope of license renewal or did not identify as being subject to an AMR. On the basis of this review, the staff requested additional information regarding the ESV building roof and siding. The drawings submitted by the applicant did not include the roof of the ESV building. In addition, the roof and siding were not listed in Table 3-1 of the LRA Amendment as being within the scope of license renewal. The staff asked the applicant whether the roof and siding are within the scope of license renewal and also asked the applicant to describe the roof system. In its response by an e-mail (which was documented in the RAI response summary of November 18, 1999), the applicant stated that the roof and siding are structural components of the ESV building but they are not within the scope of license renewal because they do not meet any of the scoping criteria under 10 CFR 54.4(a). The roof and siding are not required to provide shelter/protection to safety-related equipment, or structural and/or functional support to safety-related and non safety-related equipment within the scope of license renewal. The applicant stated that degradation or loss of the roof or siding would not result in loss of intended functions for any structure, system, mechanical component, or electrical component. Because these components are not within the scope of license renewal, the roof and siding are not subject to AMR and, therefore, are not listed in Table 3-1 of the LRA Amendment.

As a result of the above review, the staff found no omissions by the applicant on scoping the structural components. The staff also found that all the within the scope structural components are subject to an AMR. Therefore, the staff has reasonable assurance that the applicant has properly identified those SCs associated with the ESV building and trenches as being within the scope of license renewal.

2.2.3.6.10.2.2 Review Findings for Essential Siphon Vacuum Building and Trenches

On the basis of the above review, the staff concludes that there is reasonable assurance that the applicant has properly identified the structural components of the ESV building and trenches 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.

2.2.3.7 Electrical Components

In Section 2.6, "Electrical Components," of Exhibit A of the LRA, the applicant described the technical information related to electrical components at the ONS site that are within the scope for license renewal and identified which of those electrical components are subject to an AMR.

2.2.3.7.1 Summary of Technical Information in the Application

For scoping purposes, the applicant grouped all plant electrical components into one of three categories:

Category 1: Electrical components that are designated as QA Condition 1 and are scoped in because they meet the criteria of 10 CFR 54.4(a) and are subject to an AMR.

Category 2: Four selected groups of electrical components that do not meet the 10 CFR 54.4(a) criteria and are scoped out (these are electrical components associated with (1) the 525-kV switchyard, (2) the Jocassee, Calhoun, Oconee, and Dacus 230-kV transmission lines, (3) the radwaste facility, and (4) the Oconee retail substation. These electrical components are not included in the AMR.

Category 3: All remaining electrical components that are not in Category 1 or Category 2 and are included in the scope of the review.

On the basis of this scoping methodology, all electrical components at the ONS are within the scope of license renewal, except for the four groups of components identified in Category 2 above. In accordance with this scoping methodology, the applicant provided a list of all of the electrical device types and determined which of the ONS electrical device types perform their intended function without moving parts, without a change in configuration or properties, or are not subject to replacement based on a qualified life or specified time period. As a result of the applicant's scoping methodology, the following electrical device types were identified as subject to an AMR for license renewal:

- bus
  - isolated phase bus
  - nonsegregated-phase bus
  - segregated-phase bus
  - switchyard bus

- insulated cables and connections
- insulators (high-voltage equipment)
- transmission conductors

In the LRA, the applicant has identified the following intended functions for the listed electrical components:

Bus, insulated cables & connections, and transmission conductors	Provide electrical connection between two sections of an electrical circuit.
Insulators (high-voltage equipment)	Insulate and support an electrical conductor.

Subsequent to completing the electrical scoping process for the ONS, the applicant reviewed the results of the Oconee Safety-Related Designation Clarification (OSRDC) project to verify that the four selected groups of electrical components referenced in scoping Category 2 are not required to meet the criteria in 10 CFR 54.4(a)(1) or (a)(2). The OSRDC project generated a list of all ONS electrical components required to meet the criteria of 10 CFR 54.4(a)(1) or (a)(2). For electrical scoping verification, the location of each component on the OSRDC list was identified and verified to confirm that none of the components was associated with the four selected groups of electrical components identified in scoping Category 2. The applicant stated that the results of the OSRDC study verified that the four selected groups of electrical components in scoping Category 2 are not required to meet the criteria in 10 CFR 54.4(a)(1) or (a)(2).

2.2.3.7.2 Staff Evaluation

The staff reviewed Section 2.6 of Exhibit A 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 the requirements of 10 CFR 54.21(a)(1). After completing the initial review, the staff issued a request for additional information (RAI) on November 25,1998, and met with representatives of the applicant on March 11,1999, to discuss RAI 2.6-1 regarding the methodology for electrical scoping. On February 17, 1999, the staff received the applicant's response to the November 25, 1998 RAIs. On March 18, 1999 and May 10,1999, the staff received revised responses to the original RAIs.

2.2.3.7.2.1 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 whether the applicant had properly identified the electrical components within the scope of license renewal. The applicant chose to group all plant electrical components into one of three categories as detailed in Section 2.2.3.7.1 above.

Structures and Components Subject to an Aging Management Review

The starting point of the integrated plant assessment began with the applicant identifying the following ONS electrical device types as part of the screening and scoping process:

- alarm units
- analyzers
- annunciators
- batteries
- chargers
- circuit breakers
- converters
- communication equipment
- electrical controls and panel
- internal component assemblies
- electrical penetration assemblies
- elements
- fuses
- generators
- heat tracing
- heaters
- indicators
- insulated cables and connections
- insulators
- inverters
- isolated-phase bus
- isolators
- light bulbs
- load centers
- loop controllers
- meters
- motor control centers
- motors
- non-segregated phase bus
- power distribution panels
- power supplies
- radiation monitors
- recorders
- regulators
- relays
- resistance temperature detectors (RTDs)
- segregated phase-bus
- sensors
- signal conditioners
- solenoid operators
- solid-state devices
- surge arresters
- switches
- switchgear
- switchyard bus
- thermocouples
- transducers
- transformers
- transmission conductors
- transmitters
- uninsulated ground conductors

Following the development of the preceding ONS electrical device type list, the applicant's process screened the electrical components in accordance with the requirements of 10 CFR 54.21(a)(1)(i), followed by 10 CFR 54.4(a) scoping, and further screening in accordance with 10 CFR 54.21(a)(1)(ii). On the basis of this screening and scoping process, the staff finds that there is reasonable assurance that Section 2.6 of Exhibit A of the LRA has appropriately identified the electrical component device types listed above as being within the scope of license renewal.

In the second step of the staff evaluation, the staff reviewed the results from the application of the criteria of 10 CFR 54.21(a)(1)(i), 10 CFR 54.4(a), and 10 CFR 54.21(a)(1)(ii) to the above-listed electrical components, to determine whether the applicant had properly identified the electrical components within the scope of license renewal and subject to an AMR. The staff reviewed the selected electrical components identified by the applicant as within the scope of license renewal to verify that they had been identified as subject to an AMR because they perform an intended function without moving parts or without a change in configuration or properties, and that they are not subject to replacement on the basis of a qualified life or specified time period. From the preceding list, the applicant identified the following electrical device types that are subject to an AMR:

- Bus
  - isolated phase bus
  - nonsegregated-phase bus
  - segregated-phase bus
  - switchyard bus

- Insulated cables and connections
- Insulators (high-voltage equipment)
- Transmission conductors

The staff reviewed the information submitted by the applicant to verify that the applicant had not omitted or made any mistakes in the classification of electrical components requiring an AMR. The staff requested additional information relating to cables/connections used for fire detectors and pump motors and switchgear stored in warehouses that were determined by the applicant not to be subject to an AMR for license renewal.

In Section 2.6.6.1.2 of the application, the applicant identified insulated cables and connections used for fire detectors as part of the fire detection system and excluded them from an AMR because they are replaced based on a performance or condition monitoring program. In response to RAI 2.6-4, the applicant referenced the discussion on excluding components from an AMR on the basis of performance or condition monitoring in the SOC, Section III.f.(I)(b) and 10 CFR 54.21 (a)(1)(ii) as its justification for excluding fire detector cables and connections from an AMR. However, the applicant also stated that the fire detector cables are not physically different from other insulated cables.

In the SOC, Section III.f.(I)(b), the Commission states that there is no generic exclusion for components that are replaced based on performance or condition. An applicant may exclude from an AMR components or structures that are replaced on the basis of specific performance and condition monitoring activities if the following two conditions are met: 1) that the applicant identifies those SCs in the LRA that are being excluded based on performance and condition monitoring, and 2) that the applicant submit a site-specific justification for the exclusion of these components. Therefore, the staff considered this Open Item 2.2.3.7-1, and told the applicant that they need to either provide a plant-specific justification for excluding these components from an AMR or include them in an AMR. By letter dated October 15, 1999, Duke has included the fire detector cables and connections in the scope of components requiring an AMR. Open Item 2.2.3.7-1 is closed.

During a plant walkdown at the ONS, the staff identified a generic renewal issue regarding exclusion of equipment from an AMR that meets the scoping criteria of 10 CFR 54.4 but is kept in storage. Specifically, this issue focuses on the replacement of pump motors, switchgear, and electrical cables associated with the low-pressure injection, high-pressure injection, or low-pressure service water that may be required for cold shutdown in order to comply with Appendix R to 10 CFR Part 50, which requires the plant to be in cold shutdown within 72 hours after a specific event(s) involving a fire. The identification of the SCs that are excluded in 10 CFR 54.21(a)(1)(i) presumes that they are installed in the plant and are challenged by operation, testing, or maintenance. The logic that was used to screen-out SSCs that perform active functions does not apply to pump, motors, and switchgear stored in warehouses because these components are not challenged until they are installed during an event, and called upon to perform an immediate function. Therefore, the staff believes that these pumps, motors, and switchgear should be subject to an AMR. This was Open Item 2.2.3.7-2.

By letter dated October 15, 1999, Duke stated that Appendix R equipment stored in the warehouse is routinely inspected, tested, and maintained, and as such, are not subject to an AMR. The rule does not require an AMR of active components that are routinely tested, inspected, and maintained. Therefore, the staff considers Open Item 2.2.3.7-2 closed.

2.2.3.7.2.2 Review Findings for Electrical Components

The staff has reviewed the information in Section 2.6 of Exhibit A of the LRA and additional information submitted by the applicant in response to the staff's RAIs and conference calls to clarify the response. The staff has determined that there is reasonable assurance that the applicant has appropriately identified the electrical components subject to an AMR to meet the requirements stated in 10 CFR 54.21(a)(1).

3 AGING MANAGEMENT REVIEW

Chapter 3 of this SER provides the staff's evaluation of Duke's aging management review. The applicant provided a proposed supplement to the final safety analysis report (FSAR) in Exhibit B to the license renewal application (LRA), in accordance with 10 CFR 54.21(d). The purpose of the FSAR supplement is to provide an appropriate description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses, so that any future changes to the programs or activities that may affect their effectiveness will be controlled under 10 CFR 50.59.

The content of the FSAR supplement is dependent upon the final bases for the staff's safety evaluation. Therefore, the issue of the information which would be required to be contained in the FSAR supplement was designated as Open Item 3.0-1 in the June 16, 1999, SER. The staff has now concluded its evaluation, and the information which the staff has determined must appear in the FSAR supplement will be addressed by the staff prior to issuing a renewed license. A condition will be included in the renewed license requiring that the information be incorporated into the UFSAR at the next update required by 10 CFR 50.71(e) after issuance of the renewed license. Therefore, Open Item 3.0-1 is closed.

3.1 Applicable Aging Effects for Mechanical System Components

3.1.1 Introduction

Duke described its aging management review (AMR) of the mechanical system components for license renewal in Exhibit A of the LRA Sections 3.5.1. "Description of the Process To Identify the Applicable Aging Effects for Mechanical System Components" and 3.5.2, "Applicable Aging Effects for Mechanical System Components." Duke began the process of identifying the aging effects applicable to these mechanical system components by reviewing the potential aging effects defined in industry literature. From this set of potential aging effects, the component materials, operating environment, and operating stresses were used to determine the applicable aging effects for each component subject to an AMR. These applicable aging effects were then validated by a review of industry and ONS-specific operating experience to ensure that all applicable aging effects were identified for the AMR. In many instances, applicable aging effects were determined irrespective of the specific component type being evaluated because different component types constructed from the same material, located in the same environment, and operating under similar operating stresses will experience similar aging effects. The process is described in detail in Section 3.2 of Exhibit A of the LRA.

In Section 3.5.2 of the LRA, "Applicable Aging Effects for Mechanical System Components," Duke described the applicable aging effects for various material-environment combinations. Duke then applied the aging effects identified in this section of the LRA to the subsequent sections of the LRA that describe the Oconee systems. However, the staff identified that in some specific instances, the applicant did not consistently apply the aging effects identified in this section of the LRA to the subsequent system sections nor did the applicant discuss, for these specific instances, why the aging effects were omitted. The staff identified this discrepancy as Open Item 3.1.1-1. This Open Item is relevant to the following environments: air, oil, raw water, treated water and ventilation air. Duke provided its response to this open item in its October 15, 1999 submittal. The staff found the applicant's response acceptable and considers Open Item 3.1.1-1 closed. We provide our detailed evaluation of Duke's response to this open item, for each environment, in the "Staff Evaluation" section of this SER (Section 3.1.3.1).

3.1.2 Summary of Technical Information in the Application

The mechanical system components that require an AMR were grouped into seven environments (six internal environments and a set of five external environments) in order to facilitate the identification of the applicable aging effects. The groupings are based on the environments to which the components are primarily exposed. In some instances, portions of a mechanical system may be exposed to one environment and a smaller portion may be exposed to a second environment. For example, air can occupy the upper portion of a partially filled fuel oil tank. Each of the seven operating environments is described briefly below:

- The air/gas internal operating environment comprises systems within the scope of license renewal using dry instrument air and compressed gases such as air, carbon dioxide, hydrogen, halon, and nitrogen.
- The borated water internal operating environment comprises all systems within the scope of license renewal using borated water.
- The oil/fuel oil internal operating environment comprises systems within the scope of license renewal using fuel oil (liquid hydrocarbons used to fuel diesel engines) and lubricating oil (low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication).
- The raw water internal operating environment comprises systems within the scope of license renewal using water from Lake Keowee.
- The treated water internal operating environment comprises all systems within the scope of license renewal using demineralized water, except those using borated water that is also demineralized.

- The ventilation air internal operating environment comprises filtered and unfiltered ventilation systems within the scope of license renewal.

- The external surface operating environment set comprises the reactor building environment, sheltered environment, yard environment, underground environment, and embedded environment.

The applicant addressed each of these operating environments according to the component materials in order to determine the applicable aging effects that may apply to each material. For each operating environment, the applicant listed the affected mechanical systems, identified the materials of construction, and determined the applicable aging effects by performing a review of the industry and ONS-specific experience that is relevant to those mechanical system components. The LRA also contained information about the association of aging effects and aging management programs with specific components for each individual component. This information appears in Tables 3.5-1 through 3.5-12 of the LRA. Further, the applicable aging effects and associated aging management programs are addressed on a system-by-system basis in Sections 3.5.3 through 3.5.11 of the application for the ONS's mechanical system components, and in Sections 3.5.12 and 3.5.13 for mechanical components within the Keowee Hydroelectric Station and standby shutdown facility.

Listed below are the aging effects that the applicant has determined are applicable to the mechanical system components and those effects that will need to be managed to ensure an acceptable performance during the extended periods of operation.

- Loss of material from general corrosion, boric acid wastage, galvanic corrosion, crevice corrosion, pitting corrosion, erosion (including erosion caused by abrasive wear, erosive wear, cavitational wear, and droplet impingement wear), erosion-corrosion, microbiologically induced corrosion, or selective leaching.

- Fouling from macro-organisms, precipitation, or silting. Fouling is not a material degradation phenomenon; but is an aging effect that could cause the loss of a component-intended function for a limited set of component geometries in raw water systems.

- Cracking is service-induced cracking (initiation and growth) of base metal or weld metal caused by hydrogen damage, stress corrosion, intergranular attack, or vibration.

- Change in material properties is a reduction in fracture toughness caused by hydrogen embrittlement, radiation embrittlement, or thermal aging. Change in material properties was considered in all mechanical system components falling within the scope of license renewal. Except for the reactor coolant system components, discussed in Section 3.4 of Exhibit A of the LRA, change in material properties was not found to be an applicable aging effect for the mechanical system components.

- Distortion, which is a physical property change in a component, is caused by plastic deformation from the temperature-related phenomenon of creep. Components within Oconee are not exposed to the required high temperatures necessary for this mechanism to occur. Therefore, distortion is not considered an applicable aging effect for any of the mechanical system components at Oconee.

3.1.2.1 Time-Limited Aging Analysis

In Section 5.5, "Time-Limited Aging Analysis for Mechanical Components," of Exhibit A of the LRA, the applicant indicates that there are no time-limited aging analyses (TLAAs) applicable to the mechanical system components being evaluated in this section.

3.1.3 Staff Evaluation

As discussed in Section 3.1.2 above, the applicable aging effects for mechanical system components that require an AMR were grouped into six internal environments and one (group of five) external environments. Such grouping facilitates the identification of the applicable aging effects. The groupings are based on the environments to which the components are primarily exposed. The applicant addressed the aging management programs associated with aging effects related to the six internal environments on a system-by-system basis in Sections 3.5.3 through 3.5.11 of the LRA for the ONS's mechanical system components and in Sections 3.5.12 and 3.5.13 for mechanical components within the Keowee Hydroelectric Station and standby shutdown facility.

The staff's evaluation of these sections is documented in sections 3.5 through 3.7 of this SER. Further, the staff reviewed Sections 3.5.1 and 3.5.2 of Exhibit A of the LRA to determine whether the applicant has adequately identified the effects of aging on the mechanical system components so that those effects are managed during the period of extended operation as required by 10 CFR 54.21(a)(3). The staff's review and evaluation of applicable aging effects and associated environments are documented below.

3.1.3.1 Effects of Aging

Listed below are the results of the staff review of each of the seven operating environments and component materials that were identified by the applicant as being applicable to the mechanical components addressed in this section.

3.1.3.1.1 Applicable Aging Effects for an Air/Gas Environment

In the LRA, the applicant listed as being within the scope of license renewal 12 mechanical systems that have components exposed to an air/gas internal operating environment. For those 12 systems, the applicant identified the materials and specific air/gas environment combinations as follows: carbon steel exposed to air and nitrogen, chrome-molybdenum exposed to air, and stainless steel exposed to air, hydrogen, and nitrogen. The applicable aging effects for those materials exposed to an air, hydrogen, and nitrogen environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for carbon steel and chrome-molybdenum, materials in air environments containing moisture. General corrosion results from chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes in a buildup of corrosion products. The stainless steel materials in the plant/air environments are resistant to general corrosion.

Loss of material from pitting corrosion is an applicable aging effect for carbon steel, chrome-molybdenum, and stainless steel materials in an air environment that has concentrated contaminants present such as halide ions, particularly chloride ions. Pitting corrosion is a form of localized attack that results in depressions in the metal. The primary factor affecting the occurrence and rate of pitting corrosion is the severity of the contaminants in the air environment surrounding the metal.

Loss of material from galvanic corrosion in an air environment can occur when materials with different electrochemical potentials are in contact in a wetted location. In all galvanic couples involving carbon steel, chrome-molybdenum, and stainless steel, the lower potential (more anodic) materials, such as the carbon steel and chrome-molybdenum materials, would be preferentially attacked in a galvanic couple.

Carbon steel and stainless steel in a nitrogen environment have no aging effects since the nitrogen is an inert gas which has no effects on the corrosive resistance of the carbon or stainless steel materials. Stainless steel in a hydrogen environment has no aging effects since hydrogen has no affect on the corrosive resistance of stainless steel material.

The applicant also reviewed the industry experience which revealed that no other aging effects were identified beyond those noted in this section. Further, the ONS operating experience was reviewed to validate the applicable aging effects identified for carbon steel, chrome-molybdenum, and stainless steel components in an air/gas environment. In this review, the applicant surveyed documented instances of component aging and interviewed responsible engineering personnel. No additional aging effects were identified from this review.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to air/gas environments. Up-to-date industry and ONS-specific experience substantiate this conclusion.

As discussed in the introduction to this chapter (subsection 3.1.1), the staff found that Duke did not consistently apply the aging effects identified for an air environment to the subsequent system sections of the LRA. The staff identified this discrepancy as Open Item 3.1.1-1. In its

October 15, 1999 response, Duke stated that the aging effects associated with an air environment do not apply globally to all Oconee systems because of system-specific characteristics. Duke provided those system-specific characteristics which include the presence of instrument air dryers to eliminate moisture (this applies to the carbon steel components in the instrument air system, leak rate test system, and standby shutdown facility starting air system), oil films that prevent exposure to moisture (this applies to the carbon steel components in the reactor coolant pump motor oil collection system, the carbon steel pipe and tanks in the Keowee hydroelectric station governor oil and turbine guide bearing oil systems, and the carbon steel tank in the standby shutdown facility diesel generator fuel oil system), or infrequent system use (this applies to the cast iron pump casing in the standby shutdown facility auxiliary service water system). The staff agrees that when there is little or no exposure to moisture, loss of material is not an applicable aging effect. The staff concludes that Duke provided appropriate justification for its identification of applicable aging effects for components exposed to an air environment. The staff considers Open Item 3.1.1-1, as it relates to an air environment, closed.

3.1.3.1.2 Applicable Aging Effects for a Borated Water Environment

In Section 3.5.2.2 of Exhibit A of the LRA, the applicant indicated that 10 mechanical systems have the following component materials exposed to a borated water environment: carbon steel, Inconel (a nickel-based alloy), and stainless steel. Because the carbon steel material is unique to the borated water storage tank in the low-pressure injection system, the applicable aging effects for it are discussed in Section 3.5.5.3 of Exhibit A of the LRA. The staff's review of Section 3.5.5.3 of Exhibit A of the LRA is documented in Section 3.5 of this SER. The reactor coolant system, which also has components exposed to a borated water environment, is addressed in Section 3.5.4 of Exhibit A of the LRA. The staff's review of Section 3.5.4 is documented in Section 3.4 of this SER. With these exceptions, the applicable aging effects for Inconel and stainless steel in a borated water environment are discussed below.

Loss of material from pitting corrosion is an applicable aging effect for Inconel and stainless steel in a borated water environment under certain relevant conditions. Pitting corrosion is a form of localized attack that results in depressions in the metal. Oxygen is required for the initiation of pitting corrosion, and halogens and sulfates are required for continued dissolution of the material. For a borated water environment, two sets of relevant conditions can lead to pitting corrosion. The first set of relevant conditions needed for the occurrence of pitting corrosion is the continual presence of halogens in excess of 150 ppb, oxygen in excess of 100 ppb, and stagnant or low-flow conditions. A second set of relevant conditions needed for the occurrence of pitting corrosion is the continuing presence of sulfates in excess of 100 ppb, oxygen in excess of 100 ppb and stagnant or low flow conditions. If either set of relevant conditions are satisfied, loss of material from pitting corrosion is an applicable aging effect for Inconel and stainless steel materials in a borated water environment.

Cracking from stress corrosion and intergranular attack of the Inconel and stainless steel materials in a borated water environment is an applicable aging effect under certain relevant conditions. Stress corrosion cracking and intergranular attack require a combination of a susceptible material, a corrosive environment, and tensile stress. For Inconel and stainless steel, the relevant conditions required for stress corrosion cracking are the continuing presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb. The relevant conditions for intergranular attack in Inconel and stainless steel are the continuing presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb and temperatures in excess of 200°F.

In order to validate the set of applicable aging effects for mechanical components exposed to an internal operating environment of borated water, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to borated water. Up-to-date industry and ONS-specific experience substantiate this conclusion.

3.1.3.1.3 Applicable Aging Effects for an Oil/Fuel Oil Environment

In the LRA, the applicant listed five mechanical systems within the scope of license renewal that have components exposed to an oil/fuel oil environment. For these five systems, the applicant identified that component materials exposed to a oil/fuel oil environment are brass, bronze, carbon steel, copper, and stainless steel. The applicable aging effects for these materials in an oil/fuel oil environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for carbon steel in oil/fuel oil environment at locations containing water. Since any significant amount of water contamination would accumulate at the lower portions of components, such as tank bottoms, only a limited portion of the carbon steel components would be affected by general corrosion. General corrosion is the result of a chemical or electrochemical reaction on the material when both oxygen and moisture are present. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products. The stainless steel, brass, bronze, and copper in the plant oil/fuel oil environments are resistant to general corrosion.

Loss of material from pitting corrosion is an applicable aging effect for brass, bronze, carbon steel, copper, and stainless steel materials in an oil/fuel oil environment at locations containing oxygenated water and such contaminants as halide ions, particularly chloride ions. Pitting corrosion is a form of localized attack that results in depressions in the metal. Oxygen is required for the initiation of pitting corrosion and halogens or sulfates are required for continued dissolution of the material.

Loss of material from crevice corrosion is an applicable aging effect for brass, bronze, carbon steel, copper, and stainless steel materials in an oil/fuel oil environment at locations containing oxygenated water. Oxygen is required for the initiation of crevice corrosion. Oil and fuel oil do not contain oxygen in sufficient quantities for crevice corrosion to occur. Water contamination of the oil and fuel oil is required for the introduction of oxygen. Since any significant amount of water contamination would accumulate at the lower portions of the system in components such as tank bottoms, only a limited portion of the components would be affected by crevice corrosion.

Loss of material from galvanic corrosion in an oil/fuel oil environment can occur only when materials with different electrochemical potentials are in contact in the presence of water. Since any significant amount of water contamination would accumulate at the lower portions of the system in components such as tank bottoms, only a limited portion of the components within a system would be affected by galvanic corrosion. In all galvanic couples, the lower potential (more anodic) material would be preferentially attacked. That is the more anodic material would corrode while the less anodic material would not corrode. In the oil and fuel oil environment, the lower potential carbon steel material would be preferentially attacked.

Loss of material from microbiologically induced corrosion (MIC) is an applicable aging effect for brass, carbon steel, copper, and stainless steel materials exposed to fuel oil. MIC is a localized, corrosive attack accelerated by the influence of microbiological activity. Microbiological organisms present in the fuel oil can produce corrosive substances as a byproduct of their biological processes that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion.

Cracking from stress corrosion of the stainless steel material in a fuel oil environment is an applicable aging effect at locations containing oxygenated water. Stress corrosion cracking is an aging effect requiring a combination of a susceptible material, a corrosive environment, and tensile stress. Since tensile stresses are unknown, the stresses are assumed to be sufficient to initiate stress corrosion cracking if the other conditions for its occurrence are met. Since any significant amount of water contamination would accumulate at the lower portions of the system in components such as tank bottoms, only a limited portion of the components would be affected by stress corrosion cracking.

In order to validate the set of applicable aging effects for mechanical components exposed to an oil/fuel oil internal operating environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to oil/fuel oil environment. Up-to-date industry and ONS-specific experience substantiate this conclusion.

As discussed in the introduction to this chapter (subsection 3.1.1), the staff found that Duke did not consistently apply the aging effects identified for an oil environment to the subsequent system sections of the LRA. The staff identified this discrepancy as Open Item 3.1.1-1. In its October 15, 1999 response, Duke stated that the aging effects associated with an oil environment do not apply globally to all Oconee systems because of system-specific characteristics. Duke provided those system-specific characteristics which include the use of lubricating oil additives to prevent corrosion (this applies to the stainless steel valve bodies and tubing in the reactor coolant pump motor oil collection system and the stainless steel valve bodies and tubing in the Keowee hydroelectric station governor oil system), a closed system design that prevents moisture accumulation (this applies to the components in the Keowee hydroelectric station generator high pressure oil system), or a continuously recirculating operation that prevents moisture accumulation (this applies to the components in the Keowee hydroelectric station turbine guide bearing oil system). The staff agrees that with the presence of additives and the absence of significant moisture, loss of material is not an applicable aging effect. The staff concludes that Duke provided appropriate justification for its identification of applicable aging effects for components exposed to an oil environment. The staff considers Open Item 3.1.1-1, as it relates to an oil environment, closed.

3.1.3.1.4 Applicable Aging Effects for a Raw Water Environment

In the LRA, the applicant listed nine mechanical systems within the scope of license renewal that have components exposed to a raw water internal operating environment. For these nine systems, the component materials exposed to a raw water environment are admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel. The applicable aging effects for these materials in a raw water environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, and ductile cast iron component materials in a raw water environment. General corrosion is the result of a chemical or electrochemical reaction on the material when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products. The stainless steel materials in the plant raw water environments are resistant to general corrosion.

Loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel materials in a raw water environment. Pitting corrosion is a form of localized attack that leaves depressions in the metal. Oxygen is required for the initiation of pitting corrosion and halogens or sulfates are required for continued dissolution of the material. Pitting corrosion can be inhibited by maintaining an adequate flow rate, which prevents impurities from adhering to the material surface. The more susceptible locations for pitting corrosion to occur in materials in a raw water environment are locations of low or stagnant flow.

Loss of material from galvanic corrosion in a raw water environment can occur only when materials with different electrochemical potentials are in contact in the presence of water. In all galvanic couples involving admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel, the lower potential (more anodic) brass, bronze, carbon steel, copper, 90-10 copper-nickel, cast iron and ductile cast iron materials would be preferentially attacked in a galvanic couple.

Loss of material from MIC is an applicable aging effect for admiralty brass, brass, bronze, carbon steel, cast iron, copper, 90-10 copper-nickel, ductile cast iron, and stainless steel materials exposed to raw water. MIC is a localized, corrosive attack accelerated by the influence of microbiological activity. Microbiological organisms present in the raw water can produce corrosive substances as a byproduct of their biological processes that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion.

Loss of material from selective leaching is an applicable aging effect for cast iron component materials in a raw water environment. Ductile cast iron is not susceptible to selective leaching because the material properties are different from cast iron. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

In order to validate the set of applicable aging effects for mechanical components exposed to a raw water internal operating environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to raw water environment. Up-to-date industry and ONS-specific experience substantiate this conclusion.

As discussed in the introduction to this chapter (subsection 3.1.1), the staff found that Duke did not consistently apply the aging effects identified for a raw water environment to the subsequent system sections of the LRA. The staff identified this discrepancy as Open Item 3.1.1-1. In its October 15, 1999 response, Duke stated that the aging effects associated with a raw water environment do not apply globally to all Oconee systems because of system-specific characteristics. Duke provided those system-specific characteristics which demonstrated that the components in question do not support a system intended function and therefore require no aging management review. The staff found Duke provided a reasonable and justifiable explanation of why the components in question do not support a system intended function (this applies to the cast iron pump casing, recirculating cooling water heat exchangers and screens of the condenser circulating water system, tubing of the high pressure service water system, and the heat exchanger shell, tubes and tubesheet in the Keowee hydroelectric station turbine guide bearing oil system). The staff therefore agrees that there is no need to identify aging effects for these particular components because no aging management review is required. For two other components exposed to raw water, Duke provided details on the design and operation of the systems (e.g., very high flow rates, infrequent use of the component, turbulence and/or very large diameter piping) that render fouling, which was the aging effect of concern to the staff, unlikely to impact the intended function of these components (this applies to the valve bodies in the condenser circulating water system and the cast iron pump casing in the high pressure service water system, tubing and the cast iron pump casing in the Keowee hydroelectric station service water system, and the cast iron and carbon steel pump casings in the standby shutdown facility auxiliary service water system). The staff agrees that these characteristics render fouling unlikely to impact the system intended function. The applicant did agree with the staff that fouling is an applicable aging effect for the component coolers of the low pressure service water system and provided an appropriate aging management program for the coolers. The staff's evaluation of this particular aspect may be found in Section 3.6.1 of this SER. In summary, the staff concludes that Duke provided appropriate justification for its identification of applicable aging effects for components exposed to a raw water environment. The staff considers Open Item 3.1.1-1, as it relates to a raw water environment, closed.

3.1.3.1.5 Applicable Aging Effects for a Treated Water Environment

In the LRA, the applicant listed nine mechanical systems within the scope of license renewal that have components exposed to a treated water operating environment. For these nine systems, the component materials exposed to a treated water environment are admiralty brass, brass, carbon steel, cast iron, copper, low-alloy steel, and stainless steel. The applicable aging effects for these materials in a treated water environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for admiralty brass, brass, carbon steel, cast iron, copper, and low-alloy steel in a treated water environment because of the presence of oxygen. General corrosion is the result of a chemical or electrochemical reaction on the material when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes the buildup of corrosion products. The stainless steel materials in the treated water environments are resistant to general corrosion.

Loss of material from pitting corrosion is an applicable aging effect for admiralty brass, brass, carbon steel, cast iron, copper, low-alloy steel, and stainless steel materials in a treated water environment under certain conditions. Pitting corrosion is a form of localized attack that leaves depressions in the metal. Oxygen is required for the initiation of pitting corrosion and halogens or sulfates are required for continued dissolution of the material. For a treated water environment, two sets of relevant conditions can lead to pitting corrosion. The first set of relevant conditions needed for the occurrence of pitting corrosion is the continuing presence of halogens in excess of 150 ppb, oxygen in excess of 100 ppb, and stagnant or low-flow conditions. A second set of relevant conditions needed for the occurrence of pitting corrosion is the continuing presence of sulfates in excess of 100 ppb, oxygen in excess of 100 ppb, and stagnant or low-flow conditions.

Loss of material from galvanic corrosion in a treated water environment can occur only when materials with different electrochemical potentials are in contact in the presence of oxygenated water. In all galvanic couples involving admiralty brass, brass, carbon steel, cast iron, copper, low-alloy steel, and stainless steel materials, the lower potential (more anodic) carbon steel, cast iron, and low-alloy steel materials would be preferentially attacked in a galvanic couple.

Loss of material from selective leaching is an applicable aging effect for cast iron component materials in a treated water environment. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Loss of material from erosion-corrosion is an applicable aging effect for carbon steel component materials in treated water systems under certain conditions. Erosion-corrosion is a term used to describe the alternating pattern of oxide erosion from fluid flow followed by corrosion of the newly exposed material surface, which is again followed by oxide erosion as the pattern repeats. Relevant conditions required for erosion-corrosion to be a concern in treated water systems include physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, and mechanical component geometry and configuration. Loss of material from erosion-corrosion is considered an applicable aging effect for carbon steel component materials in a treated water environment when the system operates more than 2 percent of plant operating time at a temperature greater than 200 °F, but where the steam is not superheated.

Cracking from stress corrosion of the stainless steel materials in a treated water environment is an applicable aging effect under certain conditions. Stress corrosion cracking is an aging effect requiring a combination of a susceptible material, a corrosive environment, and tensile stress. For stainless steel, the relevant condition required for stress corrosion cracking is the continual presence of halogens in excess of 150 ppb or sulfates in excess of 100 ppb. If either of these relevant conditions is satisfied, stress corrosion cracking is an applicable aging effect for stainless steel materials in a treated water environment.

In order to validate the set of applicable aging effects for mechanical components exposed to a treated water internal operating environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those already identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to treated water internal operating environment. Up-to-date industry and ONS-specific experience substantiate this conclusion.

As discussed in the introduction to this chapter (subsection 3.1.1), the staff found that Duke did not consistently apply the aging effects identified for a treated water environment to the subsequent system sections of the LRA. The staff identified this discrepancy as Open Item 3.1.1-1. In its October 15, 1999 response, Duke stated that the aging effects associated with a treated water environment do not apply globally to all Oconee systems because of system-specific characteristics. Duke provided those system-specific characteristics which demonstrated that the components in question do not support a system intended function and therefore require no aging management review. The staff found Duke provided a reasonable and justifiable explanation of why the components in question do not support a system intended function (this applies to the carbon steel heat exchanger shells of the emergency core cooling system and the carbon steel and brass recirculating cooling water heat exchangers of the condenser circulating water system). The staff therefore agrees that there is no need to identify aging effects for these particular components because no aging management review is required. The staff concludes that Duke provided appropriate justification for its identification of applicable aging effects for components exposed to a treated water environment. The staff considers Open Item 3.1.1-1, as it relates to a treated water environment, closed.

3.1.3.1.6 Applicable Aging Effects for a Ventilation Air Environment

In the LRA, the applicant listed six mechanical systems within the scope of license renewal that are exposed to a ventilation air environment. For these six systems, the component materials exposed to a ventilation air environment are aluminum, brass, carbon steel, copper, 90-10 copper-nickel, galvanized steel, and stainless steel. The applicable aging effects for these materials in a ventilation air environment are discussed below.

Loss of material from galvanic corrosion in a ventilation air environment can occur only when materials with different electrochemical potentials are in contact in the presence of water. In all galvanic couples involving aluminum, brass, carbon steel, copper, 90-10 copper-nickel, galvanized steel, and stainless steel materials, the lower potential (more anodic) aluminum, 90-10 copper-nickel, and galvanized steel would be preferentially attacked in a galvanic couple.

Loss of material from boric acid wastage is an applicable aging effect for aluminum, brass, carbon steel, copper, and galvanized steel in a ventilation air environment containing a concentrated boric acid solution. Leaking fluid from a pressurized mechanical system containing borated water can vaporize, suspending the borated water in the air and allowing it to be transported to and deposited within the ventilation system components. If the boric acid deposits are re-dissolved by a wetted environment in the ventilation system, the boric acid solution will concentrate. When aluminum, brass, carbon steel, copper, and galvanized steel materials are exposed to a concentrated solution of boric acid, boric acid wastage can cause volumetric loss of material. Opportunities for ONS's ventilation systems to contain such a concentrated boric acid solution are limited to the reactor building cooling system inside the reactor building. Therefore, loss of material from boric acid wastage is an applicable aging effect for the aluminum, 90-10 copper-nickel, and galvanized steel in the reactor building cooling system.

In order to validate the set of applicable aging effects for mechanical components exposed to a ventilation air internal operating environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than the aging effects identified above.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to a ventilation air environment. Up-to-date industry and ONS-specific experience substantiate this conclusion.

As discussed in the introduction to this chapter (subsection 3.1.1), the staff found that Duke did not consistently apply the aging effects identified for a ventilation air environment to the subsequent system sections of the LRA. The staff identified this discrepancy as Open Item 3.1.1-1. In its October 15, 1999 response, Duke stated that the aging effects associated with a ventilation air environment do not apply globally to all Oconee systems because of system-specific characteristics. Duke provided those system-specific characteristics which included the specific materials of construction and local environment to which these materials are normally exposed. The staff agrees that loss of material is not an applicable aging effect for these specific materials because of the benign environment to which they are normally exposed (this applies to the carbon steel components in the reactor building purge system and penetration room ventilation system and the aluminum, galvanized steel, brass, carbon steel and copper components of the control room pressurization and filtration system). The staff concludes that Duke provided appropriate justification for its identification of applicable aging effects for components exposed to a ventilation air environment. The staff considers Open Item 3.1.1-1, as it relates to a ventilation air environment, closed.

3.1.3.1.7 Applicable Aging Effects for External Surface Environments

In the LRA, the applicant described the applicable aging effects for mechanical system components resulting from exposures to a set of five external surface environments. Because components of similar material will age similarly in the same environment, the aging management programs required to manage the applicable aging effects for all component external surfaces within these environments are also identified. Specifically, in Section 3.5 of Exhibit A of the LRA, the applicant identified that the boric acid wastage surveillance program, the inspection program for civil engineering structures and components, and the preventive maintenance activities program will be used to manage the aging effects associated with external surface environments. The staff's review of these programs is documented in Sections 3.2.1, 3.2.6, and 3.2.10 of this SER.

Mechanical system components are found in the following locations at the ONS site:

- reactor building
- sheltered areas (includes auxiliary building, intake structure, turbine building, warehouse, Keowee Hydroelectric Station, and standby shutdown facility)

- yard
- underground
- embedded

The applicable aging effects for the external surfaces of component materials exposed to each of the environments identified above, along with the associated aging management programs, are discussed below.

3.1.3.1.7.1 Applicable Aging Effects for the Reactor Building

In the LRA, the applicant indicated that the external environment in the reactor building is a warm, moist air environment. Temperatures in the higher elevations inside the reactor building can reach 130 °F during normal unit operation, and relative humidity is assumed to reach as high as 100 percent. The reactor building environment is cooled by the reactor building cooling system, which consists of three cooling units that reject heat to the low-pressure service water system. In the LRA, the applicant listed 25 systems that have mechanical components exposed to the reactor building environment. The materials of construction for the mechanical components located inside the reactor building are aluminum, brass, bronze, carbon steel, copper, galvanized steel, Inconel, and stainless steel. The applicable aging effects for these materials in the reactor building environment are discussed below.

Loss of material from boric acid wastage is an applicable aging effect for the external surfaces of aluminum, brass, bronze, carbon steel, copper, and galvanized steel component materials located in the reactor building environment. Leaking fluid from a borated water system may expose the external surfaces of components made from these materials to a concentrated boric acid solution, which can ultimately lead to volumetric loss of material. Loss of material from boric acid wastage could lead to loss of the pressure boundary function.

Loss of material from general corrosion is an applicable aging effect for carbon steel materials in the reactor building environment if the material is in contact with a moist air environment. General corrosion is the result of a chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products.

Loss of material from galvanic corrosion in the reactor building environment can occur when materials with different electrochemical potentials are in contact in the presence of water, which is needed to establish the galvanic couple. In all galvanic couples involving aluminum, brass, bronze, carbon steel, copper, galvanized steel, Inconel, and stainless steel materials, the lower potential (more anodic) carbon steel would be preferentially attacked in a galvanic couple. In the reactor building environment, only systems continuously operating at a temperature at which surface condensation occurs will have water present on their external surfaces. No applicable aging effects were identified for Inconel and stainless steel in the reactor building environment.

In order to validate the set of applicable aging for mechanical component external surfaces exposed to the reactor building environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to the reactor building environment. Up-to-date industry and ONS-specific operating experience substantiate this conclusion.

3.1.3.1.7.2 Applicable Aging Effects for a Sheltered Environment

In the LRA, the applicant indicated that the ONS-defined sheltered environment contains mechanical components located in the auxiliary building, intake structure, turbine building, warehouse, Keowee Hydroelectric Station, and standby shutdown facility. The components located in these areas are exposed to moist air but are protected from dew and meteorological precipitation. The auxiliary building and standby shutdown facility are heated and cooled. The turbine building, warehouse, and Keowee Hydroelectric Station are heated in the winter and ventilated in the summer. The intake structure is neither heated nor cooled. In the LRA, the applicant listed 47 systems that have mechanical components exposed to a sheltered environment. For these 47 systems, the component materials located inside the sheltered environments are aluminum, brass, bronze, carbon steel, cast iron, chrome-molybdenum, copper, galvanized steel, low-alloy steel, and stainless steel. The applicable aging effects for these materials in the sheltered environments are discussed below.

Loss of material from boric acid wastage is an applicable aging effect for the external surfaces of aluminum, brass, bronze, carbon steel, cast iron, copper, and galvanized steel component materials located in the auxiliary building environment only. Leaking fluid from a borated water system may expose the external surfaces of components made from these materials to a concentrated boric acid solution, which can ultimately lead to volumetric loss of material. Loss of material from boric acid wastage could lead to a loss of the pressure boundary function.

Loss of material from general corrosion is an applicable aging effect for carbon steel, cast iron, chrome-molybdenum and low-alloy steel materials in the sheltered environments if the materials are in contact with a moist air environment. General corrosion is the result of a chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. General corrosion is normally characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products.

Loss of material from galvanic corrosion in the sheltered environments can occur when materials with different electrochemical potentials are in contact in the presence of water, which is needed to establish the galvanic couple. In all galvanic couples involving aluminum, brass, bronze, carbon steel, cast iron, chrome-molybdenum, copper, galvanized steel, low-alloy steel and stainless steel materials, the lower potential (more anodic) carbon steel and cast iron would be preferentially attacked in a galvanic couple. In the sheltered environments, only systems continuously operating at a temperature at which surface condensation occurs will have water present on their external surfaces; these are the raw water systems.

No applicable aging effects were identified for stainless steel in the sheltered environments.

In order to validate the set of applicable aging effects for mechanical component external surfaces exposed to the sheltered environments, the applicant reviewed industry and ONS-specific experience. The review identified no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to the ONS-defined sheltered environment. Up-to-date industry and ONS-specific operating experience substantiate this conclusion.

3.1.3.1.7.3 Applicable Aging Effects for the Yard Environment

In the LRA, the applicant listed nine systems with mechanical components exposed to the yard environment. The materials of construction for the mechanical components within the scope of license renewal located outside in the yard environment are aluminum, bronze, carbon steel, cast iron, chrome-molybdenum, galvanized steel, and stainless steel. The applicable aging effects for these materials in the yard environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for carbon steel, cast iron, and chrome-molybdenum materials in the yard environment if the materials are in contact with a moist air environment. General corrosion is the result of a chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products.

Loss of material from galvanic corrosion in the yard environments can occur when materials with different electrochemical potentials are in contact in the presence of water, which is needed to establish the galvanic couple. In all galvanic couples involving aluminum, brass, bronze, carbon steel, cast iron, chrome-molybdenum, galvanized steel, and stainless steel materials, the lower potential (more anodic) carbon steel and cast iron would be preferentially attacked in a galvanic couple. In the yard environment, only systems continuously operating at a temperature at which surface condensation occurs will have water present on their external surfaces; these are the raw water systems.

No applicable aging effects were identified for aluminum, brass, bronze, galvanized steel, or stainless steel components exposed to the yard environment.

In order to validate the set of applicable aging effects for mechanical component external surfaces exposed to the yard environment, the applicant reviewed industry and ONS-specific experience. The review revealed no additional aging effects other than those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to the yard environment. Up-to-date industry and ONS-specific experience substantiate this conclusion.

3.1.3.1.7.4 Applicable Aging Effects for an Underground Environment

In the LRA, the applicant indicated that the underground environment at ONS contains mechanical components that are located below grade. The soil and groundwater are untreated and could be corrosive to materials located there. In the LRA, the applicant listed five systems that have mechanical components exposed to an underground environment. The materials of construction for the mechanical components located in an underground environment are carbon steel, cast iron, and stainless steel. The applicable aging effects for these materials in the underground environment are discussed below.

Loss of material from general corrosion is an applicable aging effect for carbon steel and cast iron materials in the underground environment if the materials are in contact with soil or groundwater. General corrosion is the result of a chemical or electrochemical reaction between the material and the air environment when both oxygen and moisture are present. General corrosion is characterized by uniform attack resulting in material dissolution and sometimes a buildup of corrosion products.

Loss of material from pitting corrosion is an applicable aging effect for the external surfaces of carbon steel, cast iron, and stainless steel materials in an underground environment if the materials are in contact with soil or groundwater. Pitting corrosion is a form of localized attack that leaves depressions in the metal. Oxygen is required for initiation of pitting corrosion and contaminants, such as halogens or sulfates are required for continued material dissolution.

Loss of material from MIC is an applicable aging effect for the external surfaces of carbon steel, cast iron, and stainless steel materials in an underground environment if the materials are in contact with soil or groundwater. MIC is a localized, corrosive attack accelerated by the influence of microbiological activity. Microbiological organisms present in the soil or groundwater can produce corrosive substances as a byproduct of their biological processes that disrupt the protective oxide layer on the component materials, leading to a material depression similar to pitting corrosion.

Loss of material from galvanic corrosion in an underground environment can occur when materials with different electrochemical potentials are in contact in the presence of water. However, in an underground environment, galvanic corrosion occurs between the material and the surrounding soil and groundwater. Loss of material from galvanic corrosion is an applicable aging effect for the external surfaces of carbon steel, cast iron, and stainless steel components in an underground environment if the materials are in contact with the soil or groundwater.

Loss of material from selective leaching is an applicable aging effect for cast iron component materials in an underground environment if the materials are in contact with soil or groundwater. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Cracking from stress corrosion is an applicable aging effect for stainless steel in an underground environment if the materials are in contact with soil or groundwater. Stress corrosion cracking is an aging effect requiring a combination of a susceptible material, a corrosive environment, and tensile stress. Since tensile stresses are unknown, the stresses are assumed to be sufficient to initiate stress corrosion cracking if the other conditions for its occurrence are met. For stainless steel in an underground environment, the presence of soil or groundwater could provide the corrosive environment conducive to stress corrosion cracking of stainless steel.

In order to validate the set of applicable aging effects for mechanical component external surfaces exposed to the underground environment, the applicant reviewed industry and ONS-specific experience. The review of industry experience revealed no additional degradation mechanisms other than those identified in this section. The review of ONS operating experience identified a limited number of concerns with components in an underground environment. Specifically, the following occurrences were reported:

In 1992, the presence of standing water in the transformer yard and substantial quantities of water flowing down the turbine building basement wall opposite the transformer yard was reported. Upon investigation, the source of the water was found to be a small hole that was centered in a deep symmetrical indentation in a buried condenser circulating water system branch line pipe. The root cause was galvanic or pitting corrosion of the pipe at a pinhole void in the coatings.

Another, more recent, experience was reported in October 1997. A maintenance activity was performed on the main Unit 1 discharge piping from the condenser circulating water system to remove existing internal coatings that contained asbestos. During this activity, a 1-inch-diameter hole was discovered in the 11-foot diameter piping. The hole was characterized as being nearly circular with pit walls steeply tapered from the outer diameter inward, implying that the corrosion initiated on the outer surface because of the presence of soil or groundwater. Analysis by Duke metallurgists determined that the one inch diameter hole was caused by corrosion that occurred because of a local galvanic cell created by a void in the exterior coating. The void in the exterior coating occurred during the original coating application and was not caused by aging. No additional aging effects were identified from the review or from these incidents beyond those identified in this section.

The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to an underground environment. Up-to-date industry and ONS-specific experience substantiate this conclusion. Open Item 3.1.3.1.7.4-1 requested the applicant to identify all buried piping that are subject to an aging management review, their materials of construction, and their aging management programs. The staff and the applicant had a telephone conversation on June 21, 1999, where this issue was discussed. The applicant provided the code on the isometric drawings that determines if the piping is buried. Also, the applicant stated that the aging management program for all buried piping is the internal visual inspection of the 11 foot diameter piping. The surface area of the 11 foot diameter piping accounts for 80 percent of the buried piping. In its October 15, 1999 submittal, Duke provided additional information on this issue. The following systems within the scope of license renewal contain components that are buried:

- Condenser Circulating Water System
- High Pressure Service Water System
- Service Water System (Keowee)
- Standby Shutdown Facility Diesel Generator Fuel Oil System
- Turbine Generator Cooling Water System (Keowee)

The materials of construction of the components that are buried are carbon steel, cast iron, and stainless steel. One or more of these materials may appear in each of the systems listed above.

Aging of all buried components in the systems identified above is managed by the Condenser Circulating Water System Internal Coatings Inspection and the Standby Shutdown Facility Diesel Fuel Oil Tank Inspection of the preventive maintenance activities. Duke described the preventive maintenance activities in the response to RAI 4.3.8-1. The staff evaluated the preventive maintenance activities in Section 3.2.10 of this SER.

The staff finds that the applicant's program for buried piping is adequate. Open Item 3.1.3.1.7.4-1 is closed.

3.1.3.1.7.5 Applicable Aging Effects for an Embedded Environment

The embedded environment contains mechanical components within the scope of license renewal that are in contact with concrete on their external surfaces. In the LRA, the applicant listed eight systems that have mechanical components exposed to an embedded environment. The materials of construction for the mechanical components located in an embedded environment are brass, carbon steel, and stainless steel. No applicable aging effects were identified for these components in an embedded environment because of the presence of the protective concrete cover.

In order to validate that no applicable aging effects exist for the mechanical component external surfaces exposed to an embedded environment, the applicant reviewed industry and ONS-specific experience. The review confirmed that no aging effects are associated with embedded mechanical system components. The applicant concluded that no aging effects for the component materials in an embedded environment have been identified and no aging management programs are required for brass, carbon steel, and stainless steel components that are in an embedded environment, because of the presence of the protective concrete cover on their external surfaces.

The NRC staff concurs with the applicant's conclusion that no aging effects are applicable for the materials exposed to an embedded environment. This conclusion is based on the applicant's demonstration that embedded mechanical system components at ONS are protected by a protective concrete cover and because up-to-date industry and ONS-specific experience indicated that no aging effects are associated with components embedded in concrete.

3.1.3.2 Time-Limited Aging Analysis

The applicant indicated in the LRA that there are no TLAAs applicable to the mechanical system components evaluated in this section. The staff's evaluation of the Duke identification of TLAAs is given in Section 4.0 of this staff SER.

3.1.4 Conclusions

The staff has reviewed the information in Sections 3.5.1 and 3.5.2 of Exhibit A of the LRA. On the basis of that review, the staff concludes that the applicant has adequately identified the aging effects that are associated with mechanical systems components reviewed in this section.

3.2 Common Aging Management Programs

This section of the SER contains the staff's evaluation of thirteen different aging management programs that are in Exhibit A of the LRA and are referenced as a part of the aging management for two or more of the systems or structures, or both, that are evaluated in this SER. It should be noted that the staff's conclusions on its evaluations of these thirteen common aging management programs assumes that they are implemented in conjunction with other relevant aging management programs as discussed in Sections 3.3 through 4.2 of this SER for managing aging effects for a particular system or structure.

3.2.1 Boric Acid Wastage Surveillance Program

3.2.1.1 Introduction

Duke described its evaluation of its boric acid wastage surveillance program in Section 4.5 of Exhibit A of the license renewal application (LRA). The applicant credits regular, periodic walkdowns of borated water systems with managing loss of material caused by exposure to concentrated boric acid. The staff reviewed the applicant's description of the program to determine whether the applicant has demonstrated that the effects of aging caused by boric acid corrosion will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.1.2 Summary of Technical Information in the Application

Boric acid in the concentrations found in the borated water systems of a nuclear power plant will not corrode most materials. However, borated water that has leaked outside of the system may become much more concentrated due to water evaporation. Many types of materials, particularly carbon and alloy steels, suffer general corrosion when exposed to concentrated boric acid. The corrosion rates may be significant and thus, if corrosion is not managed for an extended period the resultant material loss may render a component unable to perform its intended function under current licensing basis (CLB) design loading conditions. The potential for general corrosion from exposure to concentrated boric acid cannot be eliminated; however, actions can be taken to detect and mitigate this aging effect before there is a loss of intended function. The applicant credits the boric acid wastage surveillance program with both discovery and mitigation of the aging effects (loss of material) associated with general corrosion of components from exposure to concentrated boric acid. The program consists of regular, periodic walkdowns during which plant personnel visually inspect borated systems for leaks. Timely discovery of leaks and subsequent corrective action (e.g., repair of borated water leak path and removal of concentrated boric acid residue from affected component surfaces) mitigate the effects of concentrated boric acid corrosion. The program also requires an engineering evaluation of the affected component(s) as part of the damage assessment.

The applicant credits this program for managing loss of material from exposure to concentrated boric acid for all the systems and components located in the reactor and auxiliary buildings, including the reactor coolant system components, mechanical components, and structural components discussed in Sections 3.4, 3.5, and 3.7 of Exhibit A of the LRA, respectively. In Section 4.5 of Exhibit A of the LRA, the applicant describes the boric acid wastage surveillance program for managing the aging effects associated with corrosion of components from exposure to concentrated boric acid. The program is designed to ensure the maintenance of component intended functions under all CLB conditions for the period of extended operation.

In Section 3.5.2.7 of Exhibit A of the LRA, the applicant describes the applicable aging effects for external surface environments, including potential exposure to concentrated boric acid. The applicant identified loss of material due to corrosion from concentrated boric acid on the external surfaces of aluminum, brass, bronze, carbon steel, cast iron, copper, and galvanized steel component materials located in the reactor building and auxiliary building environments. Leaking fluid from a borated water system may come in contact with the external surfaces of components made from these materials. When the water in the fluid evaporates any remaining concentration of boric acid could lead to material loss. Unchecked material loss could eventually compromise the ability of the component to perform its intended function.

3.2.1.3 Staff Evaluation

The staff evaluation of the boric acid wastage surveillance program focused on the program elements rather than details of the specific plant procedure. The staff evaluated how effectively the boric acid wastage surveillance program incorporates the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff evaluation of the applicant's quality assurance program is provided separately in Section 3.2.3 of this staff SER. Thus, these three elements will not be discussed further in this section.

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information about the boric acid wastage surveillance program contained in Section 4.5 of Exhibit A of the LRA regarding the applicant's demonstration that it will adequately manage the effects of aging from corrosion so that the intended function of the affected components will be maintained consistent with the CLB for the period of extended operation. By letter dated December 3, 1998, the staff issued a request for additional information (RAI). The applicant responded to the RAI in letters dated February 8, 1999, and February 17, 1999. In addition, the staff documented additional information from the applicant in a March 31, 1999, phone call in a meeting summary dated April 6, 1999.

Program Scope
The staff finds the scope of the boric acid wastage surveillance program acceptable because the scope is comprehensive in that it includes periodic walkdowns in every area containing borated water systems in the reactor and auxiliary buildings. The program also includes an evaluation of all components potentially affected by borated water leakage.

Preventive or Mitigative Actions
The staff finds the mitigative actions required by the boric acid wastage surveillance program acceptable because removal of concentrated boric acid and eliminating borated water leakage mitigates corrosion by minimizing the exposure of the susceptible material to the corrosive element.

Parameters Inspected or Monitored
The applicant performs visual inspections of the external surfaces in accordance with plant procedures. Plant personnel look for leakage from both insulated and uninsulated components, as well as general corrosion of a component that may result from leakage. Plant personnel look for borated water leakage indicators such as discoloration or accumulated residue on surfaces such as insulation materials or floors. The staff finds the parameters monitored (e.g., boric acid residue, borated water leakage, and discoloration of insulation) acceptable because they are conditions directly related to the degradation of components.

Detection of Aging Effects
As discussed above, the staff found the scope and inspection technique of the boric acid wastage surveillance program acceptable. The applicant stated that it performs inspections at least each refueling outage, which is consistent with industry practice. Operating experience to date appears to support the continuation of such a frequency. In addition, the applicant's technical specifications require operator actions up to and including reactor shutdown provide defense-in-depth with respect to the detection of unidentified leakage in excess of 1 gpm and, therefore, the staff considers the applicant's technical specification limits on unidentified leakage an important part of the aging management program for detecting leakage that develops between refueling outages and ensuring that leakage is identified before there is a loss of component intended function. Based on the adequate scope, inspection technique, and inspection frequency, and supplemented by the applicant's TS on unidentified leakage, the staff concludes that the boric acid wastage surveillance program is adequate to detect the aging effects before there is a loss of component intended function. This conclusion is supported by both ONS-specific and industrywide operating experience to date.

Monitoring and Trending
There are no monitoring and trending processes associated with the boric acid wastage surveillance program, and the staff did not identify a need for such.

Acceptance Criteria
The staff finds the applicant's acceptance criteria acceptable because the applicant indicated that it evaluates all borated water leaks. The applicant implements corrective actions upon discovery of leakage. Such actions include corrective actions to prevent recurrence (e.g., identifying and correcting the cause of the leak), mitigative actions to prevent corrosion (e.g., removing concentrated boric acid residue) and confirmatory actions to verify adequate corrective actions (e.g., performing subsequent walkdowns prior to plant startup to ensure effective actions). The applicant evaluates all affected components to assess practicality of continued service, repair, or replacement.

Operating Experience
The applicant reported no structural damage to any components from boric acid corrosion. The staff finds that the applicant has demonstrated that the boric acid wastage surveillance program

has been effective in preventing damage to components due to exposure to concentrated boric acid.

3.2.1.4 Conclusions

The staff has reviewed the information in Section 4.5, "Boric Acid Wastage Surveillance," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Boric Acid Wastage Surveillance' program will adequately manage aging effects associated with boric acid wastage for the period of extended operation.

3.2.2 Chemistry Control Program

3.2.2.1 Introduction

Duke described its chemistry control program (CCP) in Section 4.6 of Exhibit A of the license renewal application (LRA). It also included relevant materials from Section 3.4, "Aging Effects for Reactor Coolant Systems Components and Class 1 Component Supports;" Section 3.5, "Aging Effects for Mechanical System Components;" Section 3.4.9; "Control Rod Drive Tube Motor Housing;" Section 3.5.2, "Applicable Aging Effects for Mechanical System Components;" Section 3.7, "Aging Effects for Structural Components;" and Section 4.10, "Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetration Inspection Program." These sections address the interaction of primary, secondary, or component cooling water and diesel generator fuel oil with the components in different systems and describe the resulting aging effects. The objective of chemistry control programs described in Section 4.6 is to optimize chemistry in different systems so that damage from corrosion will be minimized.

The staff reviewed the applicant's description of the program in Section 4.6 and the relevant material in the other referenced sections of the LRA to determine whether the applicant has demonstrated that it will adequately manage the effects of aging caused by different chemistries in the plant during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.2.2 Summary of Technical Information in the Application

3.2.2.2.1 Systems Subject to Aging Management

Duke identified the following systems and components that are affected by water and diesel generator fuel oil chemistries and are within the scope of the LRA:

Primary Water:

- reactor coolant system
- low-pressure injection system
- high-pressure injection system

- coolant storage system
- chemical addition system
- pressurizer
- core flood system
- borated water storage tank
- reactor building spray system
- spent fuel pool cooling system
- spent fuel pool liner
- spent fuel storage racks
- fuel transfer canal liner plate
- structural steel and plates in spent fuel pool
- SSF reactor coolant makeup system
- control rod drive mechanism

Secondary Water:

- condensate system
- feedwater system
- emergency feedwater system
- steam generators
- chemical addition system
- main steam system

Component Cooling Water:

- component cooling system

Diesel Generator Fuel Oil

- standby shutdown facility diesel generator fuel oil system

3.2.2.2.2 Effects of Water and Fuel Oil Chemistries on Aging

Duke evaluated various aging effects for the components exposed to primary, secondary, and component cooling water, and diesel generator fuel oil. Duke also stated that the chemistry control program will satisfactorily manage the majority of these aging effects. The following aging effects were identified by the applicant:

- cracking
- loss of materials due to corrosion
- erosion/corrosion

3.2.2.2.3 Water and Fuel Oil Chemistry Programs

In the license renewal application, Duke identified the following programs contributing to control of water chemistry:

- chemistry program based on EPRI "PWR Primary Water Chemistry Guidelines," Revision 3, EPRI Report TR-105714, November 1995 (existing program)

- chemistry program based on EPRI "PWR Secondary Water Chemistry Guidelines," Revision 4, EPRI Report TR-102135-R4, November 1996 (existing program)

- component coolant chemistry control specifications (existing program)

- standby shutdown facility (SSF) fuel oil surveillances (existing program)

Duke concluded that these programs will manage primary, secondary, and component cooling water, and diesel generator fuel oil chemistry control in a way that will prevent formation of the corrosive environments that could cause damage to the affected components. This will help maintain their integrity and allow them to perform their intended functions consistent with the current licensing basis (CLB), during the period of extended operation.

3.2.2.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in the sections of Exhibit A of the Duke LRA regarding the applicant's demonstration of the water and fuel oil chemistry control programs to ensure that the effects of aging due to water and fuel oil chemistries will be adequately managed so that intended functions will be maintained consistent with the CLB for the period of extended operation for all components in the systems included in the LRA. After completing the initial review, by letter dated October 29, 1998, the staff issued several requests for additional information (RAIs). By letter dated December 14, 1998, the applicant responded to the staff's RAIs.

3.2.2.3.1 Effects of Aging

Primary, secondary, and component cooling water, and diesel generator fuel oil serve different functions in different plant systems. These systems contain components made from various materials that are exposed to different environments. Since aging effects depend on both fluid chemistry and materials of construction of the affected components, the applicant has different programs for controlling the chemistries of primary, secondary, and component cooling water and diesel generator fuel oil.

Aging Management Review

Primary Water
Primary water contains dissolved boric acid for reactivity control and lithium hydroxide for pH control. The ONS uses different boron/lithium/pH chemistry regimes for minimizing corrosive action of primary coolant. Currently, Unit 2 uses the elevated lithium chemistry regime (maintaining high pH and high concentration of Lithium), and Units 1 and 3 use coordinated chemistry regimes (maintaining constant low value of pH) . In the future, however, all three units may be placed on the elevated chemistry regime, which the applicant found to produce optimum results. Most of the components in the system containing primary water are made of stainless steel, but other materials such as Alloy 600 in the steam generators are also present. If water chemistry is not properly controlled, these components may undergo corrosion damage. The magnitude will depend on component materials and operating conditions in the system. The staff concurs with the applicant that improper water chemistry may give rise to the following aging associated effects: cracking, loss of materials from corrosion, and erosion/corrosion. The staff review did not identify any other aging effects that may be induced by primary water chemistry.

Secondary Water
Secondary water consists of demineralized water containing pH-controlling and oxygen-controlling chemicals. The components in the systems containing secondary water are constructed mostly from carbon steel, although other materials such as stainless steel, brass, cast iron, and low-alloy steel are also present. The staff concurs with the applicant that these components, when exposed to uncontrolled secondary water environment, could experience corrosion damage due to the following aging effects: cracking, loss of material from corrosion, and erosion/corrosion damage to carbon steel components. The staff review did not identify any other aging effects that may be induced by secondary water chemistry.

Component Cooling Water
Component cooling water removes heat from various power plant auxiliary systems that contain components made from a variety of materials prone to corrosion in uncontrolled water environments. Component cooling water consists of demineralized water having a chromate-phosphate treatment recommended by Babcock & Wilcox. Materials of construction for the components are carbon steel, stainless steel, and copper alloys. The staff concurs with the applicant that when not controlled, interactions between component cooling water and these materials could lead to damage resulting in the following aging effects: cracking and loss of material from corrosion and stress corrosion cracking of stainless steel components. The staff review did not identify any other aging effects that may be induced by component cooling water chemistry.

Diesel Generator Fuel Oil
Diesel generator fuel oil is stored in the standby shutdown facility diesel generator fuel oil system. It is normally stagnant and remains at ambient conditions. This oil may contain some contaminants such as water and bacteria/fungal growth, which can cause corrosion of the exposed components. The components coming in contact with the contaminated fuel oil are

constructed from carbon steel and stainless steel. The mechanisms of degradation for these components are loss of material and cracking of stainless steel components. Loss of materials by general corrosion can occur in carbon steel components only, but pitting, crevice corrosion, and microbiologically influenced corrosion (MIC) can also occur in stainless steel, brass, and copper components. In addition, when a component is coupled with the other components made of more noble metal, it can lose material by galvanic corrosion. The staff review did not identify any other aging effects that may be induced by diesel generator fuel oil chemistry.

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 water and fuel oil chemistries for aging management considerations.

3.2.2.3.2 Aging Management Programs for License Renewal

The staff evaluation of the Duke aging management programs (AMPs) related to water and fuel oil chemistries focused on the program elements rather than details of specific plant procedures. To determine whether these programs adequately mitigate the effects of aging to maintain intended functions consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements applicable to these programs: scope of program, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience. The objective of the staff's evaluation was to determine if the AMPs contain the elements essential to providing adequate aging management for all the components exposed to different water and fuel oil chemistries. Duke, in its license renewal application, has indicated that water and fuel oil chemistry control will be adequately managed by the existing programs in conjunction with other programs, will address all the relevant aging concerns, and will meet the requirements of 10 CFR Part 50, Appendix B.

The application indicated that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and that they cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of the SER. Thus, these three elements will not be discussed further in this section.

Primary Water Chemistry
Duke has a program for controlling primary water chemistry in the ONS units. Its primary objective is to protect the integrity, reliability, and availability of the plant equipment and components in primary systems by minimizing corrosion caused by primary water. The components exposed to the primary water chemistry are listed in Section 3.2.2.2.1, *(Scope of Program.)* This objective is achieved through rigorous control of water chemistry. Components in these systems are made of stainless steel and Alloy 600 materials. The applicant's current program is based on the EPRI "PWR Primary Water Chemistry Guidelines." These guidelines

were based on technical input and concurrence from U.S. nuclear steam supply system vendors, utility personnel, and water treatment experts, and lessons learned from many years of operating experience. The guidelines are considered to contain the most advanced technologies for primary water chemistry control and have been widely adopted by the industry. They include detailed description of water chemistry parameters to be monitored and the criteria for determining their acceptable values, *(Parameters Monitored or Inspected, Acceptance Criteria and Preventive Actions.)* In addition, the program provides for routinely trending chemistry data for monitored parameters, through which the applicant can identify subtle trends that may indicate an underlying operational problem (*Monitoring and Trending*). These features of the program have resulted in very satisfactory operating experience in the ONS units and no chemistry related degradation has resulted in loss of component intended function on any primary side systems or components for which the fluid chemistry is controlled. The NRC staff's experience with the EPRI program, as implemented throughout the industry, is that, in general, it is an important contributor to managing the effects resulting from water chemistry (*Operating Experience*). On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Chemistry Control Program' will adequately manage aging effects associated with primary water chemistry for the period of extended operation.

Secondary Water Chemistry
Duke has a program for controlling secondary water chemistry in the ONS units. This program affects the components exposed to the secondary water which are listed in Section 3.2.2.2.1, *(Scope of Program.)* Through rigorous control of secondary water chemistry parameters, the program manages the applicable aging effects for components in the systems containing secondary water. Components in these systems are made primarily of carbon steel, although stainless steel, Inconel, brass, cast iron, and low-alloy steel are also present. The current secondary water chemistry program at the ONS is based on the EPRI "PWR Secondary Water Chemistry Guidelines." These guidelines are based on input from U.S. nuclear steam supply system vendors, utility personnel, and water treatment experts. They recommend parameters for chemistry control, sampling and analysis frequencies, acceptance criteria, and corrective actions to be taken if specified limits for monitored parameters are exceeded. The monitored parameters include, but are not limited to, dissolved oxygen, sodium chloride, sulfate, and silica (*Parameters Monitored or Inspected and Acceptance Criteria*). Organic amines control flow assisted corrosion in the extraction piping by maintaining a more alkaline pH condition in the liquid phase of the steam-water two phase fluid. The powdered resin condensate polisher system (Powdex) helps maintain purity of the secondary water. The Powdex is effective in filtrating suspended solids and removing ionic impurities (*Preventive Actions*). In addition, the applicant trends chemistry data which can indicate operational problems (*Monitoring and Trending*). The effectiveness of the existing secondary water chemistry program is demonstrated by satisfactory operating experience of the components exposed to secondary water environment and with the exception of steam generators, no chemistry-related degradation has resulted in loss of component intended functions on any systems for which fluid chemistry is controlled. In the steam generators, Alloy 600 tubes will undergo some degradation even when exposed to the controlled secondary water chemistry environment. The operability

of the steam generators is ensured by special maintenance procedures specified in the Steam Generator Tube Surveillance Program (see Section 3.4.3.3 of this SER) (*Operating Experience*). On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Chemistry Control Program' will adequately manage aging effects associated with secondary water chemistry for the period of extended operation.

Component Cooling Water Chemistry
Duke has a program for controlling component cooling water chemistry in the ONS units. This program affects the components exposed to component cooling water which are listed in Section 3.2.2.2.1, (*Scope of Program.*) The components in the systems containing component cooling water are constructed from carbon steel, stainless steel and copper alloys. To minimize corrosion effects, the chemistry of the component cooling water must be controlled by adding suitable corrosion inhibitors. Duke has a program for providing such control by maintaining cooling water parameters at prescribed levels. The program described in the current plant operating procedure, which the NRC has accepted for controlling water chemistry, is based on Babcock & Wilcox's chromate-phosphate water treatment methodology which the NRC has accepted for controlling water chemistry (BAW - 1385, Water Chemistry Manual for 177FA Plants) (*Preventive Actions and Acceptance Criteria*). The program specifies concentrations of the water additives, sampling frequency, and corrective actions to be taken if the monitored concentrations exceed their prescribed ranges (*Parameter Monitored or Inspected*). Although the exact nature of these corrective actions may vary depending on which parameter is out of range, in general they consist of either adding chromate, biphosphate or triphosphate if the concentration of additives is too low, or placing the system in feed-and-bleed mode if a parameter exceeds its prescribed limit. The program includes monitoring of several chemistry parameters including pH, chromate-phosphate, chloride, iron, and copper. The applicant trends chemistry data and in this way can detect some operational problems that allow suitable modification to the program (*Monitoring and Trending*). Successful application of the component cooling water chemistry program is evidenced by very satisfactory operating experience in the affected systems. Iron and copper monitoring of the ONS components cooling system confirms that the applied chemistry control program resulted in extremely low corrosion rates of steel and copper alloyed metallurgies in the system (*Operating Experience*). On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Chemistry Control Program' will adequately manage aging effects associated with component cooling water chemistry for the period of extended operation.

Diesel Generator Fuel Oil
Duke has a program for controlling diesel generator fuel oil chemistry in the ONS units. This program affects the components exposed to diesel generator fuel oil in the system, which is listed in Section 3.2.2.2.1 of this SER (*Scope of Program*). These components are constructed from carbon steel, stainless steel, brass, and copper. Their corrosion is caused by the presence of water and bacterial/fungal growth in the fuel oil. Duke's program has for its objective to ensure that diesel generator fuel oil does not contain contaminants which could create conditions detrimental to the components. The program consists of standby shutdown facility

fuel oil surveillances and requires specific corrective actions to be taken if water or bacterial/fungal contents exceed acceptable limits. The program requires that new fuel oil deliveries be treated with biocide and sampled and analyzed for water content (*Preventive Actions*). The parameters monitored by the surveillance program and acceptance criteria established are consistent with those provided in ASTM D975 Standard, "Standard Specification for Diesel Fuel Oil" (*Parameter Monitored of Inspected*). The standby shutdown facility surveillances include quarterly sampling and analysis of fuel oil (*Monitoring or Trending*). A review of sample results for water contamination and bacterial/fungal activity in the fuel oil in the standby shutdown facility diesel generator fuel oil system in the Oconee plant has indicated that it is well below acceptance criteria and the results do not have a recognizable trend. Also, no instances of exceeding the accepted values either for water or for bacterial/fungal activity was recognized in the past *(Operating Experience*). Should problems be encountered, the program requires that the operations staff be notified so that appropriate corrective actions can be taken. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the Standby Shutdown Facility Fuel Oil Surveillance Program will adequately manage aging effects associated with diesel generator fuel oil for the period of extended operation.

3.2.2.4 Conclusions

The staff has reviewed the information in Section 4.6, "Chemistry Control Program," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Chemistry Control Program' will adequately manage aging effects associated with primary water chemistry, secondary water chemistry, component cooling water chemistry, and diesel generator fuel oil chemistry for the period of extended operation.

3.2.3 Duke Quality Assurance Program

3.2.3.1 Introduction

As described in Exhibit A of the LRA, Subsection 4.13, "Duke Quality Assurance Program," the applicant has established a quality assurance program that conforms to the criteria in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." In this subsection, the applicant further states that the "Quality Assurance Program is presented in the Duke Power Topical Report 'Quality Assurance Program,' DUKE-1A, which is incorporated by reference into Chapter 17 of the ONS UFSAR." The applicant's submittal also states that the quality assurance program addresses all aspects of quality assurance at Duke's nuclear power stations, including selected activities associated with the license renewal process. Specifically, Subsection 4.13 describes aspects of "corrective actions," "confirmation process," and "document control" in DUKE-1A that are pertinent to the aging management programs identified for license renewal.

3.2.3.2 Summary of Technical Information in the Application

Exhibit A of the LRA Section 4.13.1, provides a general description of the process controls, responsibilities, and actions for initiating corrective actions in response to non-conforming conditions. These process controls include procedural requirements to ensure that conditions adverse to quality are properly documented and corrected. In the case of significant conditions adverse to quality, the provisions of DUKE-1A specify that the cause of the condition is determined and that action is taken to preclude repetition. Additionally, in this section, the applicant states that site personnel responsible for the performance and verification activities of QA Condition 1 structures, systems, and components (SSCs) are to ensure that reworked, repaired, and replaced items are inspected and tested in accordance with the original inspection and test requirements or specified alternatives. These quality assurance program provisions also direct that failures of QA -Condition 1 (safety-related) SSCs are evaluated for common-cause considerations and generic implications.

Similarly, Exhibit A of the LRA Section 4.13.2 addresses the document control provisions of the applicant's quality assurance program for QA-Condition 1 SSCs, which are to be accomplished in accordance with procedures, instructions, and drawings of a type appropriate to the circumstances. This section also states that the associated documents identify the equipment necessary to perform the activity, specify test conditions and parameters, identify independent verification requirements and include appropriate acceptance criteria in order to determine if the activity was satisfactorily accomplished. With respect to maintenance, instrumentation and controls, and modification procedures for QA-Condition 1 SSCs, the applicant states in its quality assurance program that cognizant station personnel shall determine the need for explicit inspections and that the associated procedures appropriately establish inspection methods, acceptance criteria, and documentation requirements.

3.2.3.3 Staff Evaluation

On the basis of the staff's review, it was determined that Exhibit A of the LRA Subsections 4.13.1 and 4.13.2 adequately describes the applicant's corrective action and document control programs as they relate to QA-Condition 1 (safety-related) SSCs subject to an aging management review (AMR). However, ONS's AMR program applies to both safety-related and non-safety-related SSCs. Accordingly, the staff requested clarification (see RAI G-1 and RAI 4.13-1) regarding the applicant's commitment to extend 10 CFR Part 50, Appendix B requirements for corrective actions, confirmation process, and document controls to cover ONS non-safety-related structures and components subject to an AMR.

In the applicant's letter to the NRC, dated February 17, 1999, the applicant responded to the RAIs stating that it would include the non-safety-related structures and components in a separate renewal program that will be summarized in Exhibit B to the LRA. By letter, to the NRC dated May 10, 1999, the applicant provided a revised response to RAI G-1 and RAI 4.13-1. In this letter the applicant stated that their previous response to RAI G-1 was unclear with respect to the characterization of a "separate" renewal program for non-safety-related structures and components. As articulated in this letter, the applicant does not plan to implement a new, separate program specifically for license renewal to address corrective actions, confirmation processes, and administrative controls for non-safety-related structures and components subject to aging management review at ONS. Instead the applicant will use their existing 10 CFR Part 50, Appendix B corrective action program embodied in their plant Problem Investigation Process which forms the basis of the applicant's aging management program corrective action element to address these aspects for non-safety-related structures and components. The revised response letter further states that the attributes related to corrective actions, including confirmation processes, and administrative controls for non-safety-related structures and components apply to both the non-safety-related as well as the safety-related structures and components subject to AMR.

The staff requested Duke to commit to applying 10 CFR Part 50, Appendix B corrective action requirements to non-safety-related structures and components that are subject to an aging management program. This was identified as Open Item 3.2.3.3-1. By letter dated October 15, 1999, Duke provided a response to Open Item 3.2.3.3-1and a supplemental response to RAI G-1 and RAI 4.13-1. This supplemental response documented the applicant's commitment to revise the UFSAR Supplement corrective action statement for each applicable credited aging management program that contains non-safety-related structures and components. As described in the applicant's letter, the revised UFSAR Supplement will direct that specific corrective actions are to be implemented in accordance with the Program Investigation Process (PIP) which applies to all structures and components within the scope of the affected aging management program. Accordingly, the staff has determined that the applicant's revised response to these RAIs is acceptable in that it satisfies the guidance regarding corrective actions, confirmation processes, and administrative controls for structures and components subject to an AMR. Open Item 3.2.3.3-1 is closed.

3.2.3.4 Conclusions

Based on the applicant's commitment to revise the UFSAR Supplement corrective action statement for each applicable credited aging management program that contains non-safety-related structures and components and to apply selected elements of their PIP program to non-safety-related structures and components subject to an AMR, the staff has determined that there is reasonable assurance that the applicant's QA program will contain the requisite elements for corrective actions, including confirmatory processes and administrative controls, for those structures and components requiring an AMR.

3.2.4 Fire Protection Program

3.2.4.1 Introduction

Duke described its fire protection program in Section 4.16 of Exhibit A of the LRA. The existing ONS fire protection program utilizes defense in depth for a high degree of fire safety. This approach includes (1) preventing fires from starting, (2) detecting and suppressing fires quickly to limit their damage, and (3) designing the plant safety systems so that in the unlikely event of a major fire, the capability to safely shutdown the unit is maintained. The staff reviewed the applicant's description of the program to determine whether the applicant has demonstrated that the effects of aging on structures and components that serve fire protection functions will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.4.2 Summary of Technical Information in the Application

Section 2.7.2.4 of Exhibit A of the application identifies fire doors, fire walls, and fire barrier penetration seals as subject to an AMR. Section 3.7.2.4 of the application identifies the aging effects applicable to fire walls, fire doors, and fire barrier penetration seals during the extended period of operation. Fire barrier inspections will help manage the effects of aging by ensuring that the intended functions of the fire barriers will be maintained in accordance with the CLB during the extended period of operation.

Section 2.5 of the application identifies the components in the high-pressure service water system, the low-pressure service water system, and the service water system (Keowee) subject to an AMR. Section 3.5 of the application identifies loss of material due to corrosion and fouling as applicable effects of aging for these three systems. The application states that the fire water system test manages fouling of the high-pressure service water system, the low-pressure service water system, and the service water system (Keowee) components that fall under the scope of license renewal. In addition to the fire water system test, the service water piping corrosion program, the galvanic susceptibility inspection, and the cast iron selective leaching inspection help manage the loss of material for the components within these systems. The program is designed to ensure that these systems comply with the applicable National Fire Protection Association (NFPA) standards and that the systems meet the applicable selected licensee commitments in ONS UFSAR Chapter 16.

3.2.4.3 Staff Evaluation

The staff evaluation of the Duke aging management programs focused on the program elements rather than details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of the program, (2) preventative actions,

(3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the quality assurance program is provided separately in Section 3.2.3 of the SER. Thus, these three elements will not be discussed further in this section.

3.2.4.3.1 Fire Barrier Inspections

Program Scope
The fire barrier inspections program has within its scope the Unit 1, 2, and 3 fire barrier penetration seals and walls as identified in the implementing procedure and associated drawings. The scope also includes Units 1, 2, and 3 fire rated doors that are equipped with automatic or self-closing devices, and doors that are manually closed as identified in the implementing procedure. The staff finds that the applicant included the fire barriers within the scope of the fire protection program in the fire barrier inspections program.

Preventive or Mitigative Actions
There are no preventive or mitigative actions, and the staff does not see a need for any.

Parameters Inspected or Monitored
The parameters monitored are the condition of fire barrier penetration seals such as cracking, separation from walls or components, separation of layers of material, and rupture or puncture of seals. The parameters monitored for fire barrier walls, ceilings, and floors are loss of material. The parameters monitored for fire doors are as follows: (1) a visual inspection to verify that hinges of self-closing doors are complete with all screws tight and pins in good condition; (2) a visual inspection to verify that bolts and the astragal of double self-closing doors are in good condition; (3) a visual inspection to verify that tracks, trucks, cables, and chains of automatic-closing doors are in good operating condition; and (4) a visual inspection of hollow metal fire doors for holes in the skin. The staff finds that the parameters monitored include the critical parameters.

Detection of Aging Effects
The applicant performs visual inspections to detect the effects of aging described above. Visual inspections are capable of detecting the effects of aging because defects would be identified and evaluated using the corrective action program before failure would occur. Accordingly, the staff finds that visual inspections are appropriate for these inspections. These inspections are conducted at least once every 18 months on exposed surfaces of fire walls and on at least 10 percent of each type of fire penetration seal. Fire doors are visually inspected bimonthly and

functionally tested bimonthly. The staff finds the method and frequency of inspections consistent with industry operating experience. This frequency is adequate to detect defects since degradation to failure would not occur in two months.

Monitoring and Trending
There are no monitoring or trending aspects to the fire barrier inspections program, and the staff did not identify a need for any.

Acceptance Criteria
The acceptance criterion for fire barrier penetration seals is no visual indication of cracking, separation from wall, separation of layers of material, holes, and ruptures or punctures of seals. The acceptance criterion for walls, ceilings, and floors is no visual indication of holes or cracks. The acceptance criterion for fire doors is no indication of loss of material (puncture). The staff finds these acceptance criteria to be acceptable because effects of aging will be detected and will be evaluated using the corrective action program before failure would occur.

Operating Experience
The previous fire barrier inspections conducted at ONS confirm the reasonableness and acceptability of the inspection frequency and demonstrate that the degradation of the fire barrier is detected prior to loss of function. The deficiencies discovered during these inspections were related to installation problems and missing tags for the fire barrier penetration seals. One inspection identified fire doors with worn hinges and handles. Holes found in the skins of doors were attributed to installation of signs on the doors, and not aging.

The staff concludes that the applicant provided information in its licensee renewal application to demonstrate that the fire barrier inspections provide reasonable assurance that the aging effects will be managed such that the fire barriers will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.2.4.3.2 Fire Water System Test

Program Scope
The scope of the program credited for license renewal includes the high-pressure service water system, the low-pressure water system, and the service water system (Keowee) components serving a regulatory-committed fire protection function important to safety and falling within the scope of license renewal. The staff finds that the scope covers the essential fire water systems and components and is acceptable.

Preventive or Mitigative Actions
There are no preventive or mitigative actions, and the staff does not see a need for any.

Parameters Inspected or Monitored
Piping and pumps are periodically performance-tested. Fire hydrants and deluge valves are periodically flow-tested. Hose racks and some sprinkler heads are periodically inspected visually. The staff finds that these tests demonstrate that these components are able to perform their intended functions and that the parameters monitored or inspected are adequate.

Detection of Aging Effects
The effects of aging are the fouling of smaller diameter piping and loss of material due to corrosion of bronze, carbon steel, cast iron, and stainless steel exposed to raw water. The effects of aging are detected using performance testing and visual examinations. The frequency of these tests and visual examinations are based on the type of component and are managed by plant procedures. The staff finds that the methods for detecting the effects of aging are adequate because they can detect fouling (by reduced flow) and corrosion (by appearance of water and components).

Monitoring and Trending
There are no monitoring or trending aspects to the fire barrier inspections program, and the staff did not identify a need for any.

Acceptance Criteria
The acceptance criteria vary depending on the type of component and are specifically stated in the plant procedures for each inspection or test. For instance, in the service water piping corrosion program, the acceptance criterion is that no inspection location can fall below the minimum pipe wall thickness. For the cast iron selective leaching inspection program, there can be no unacceptable loss of material due to selective leaching as determined by hardness testing and engineering analysis. Acceptability of component wall thickness will be judged in accordance with the ONS component design code of record. For the galvanic susceptibility inspection program, the criterion is no unacceptable indication of loss of material due to galvanic corrosion, as determined by engineering analysis. These acceptance criteria are acceptable since they will determine if unacceptable aging has occurred and the degradation will be evaluated using the corrective action program.

Operating Experience
The fire protection standards have been in place at ONS since it received the original license. The fire water system test was enhanced after the cable fire event at Browns Ferry and in response to IE Bulletin 75-04. The program conforms with the standards set forth by the NFPA, with exceptions that are noted in engineering specifications.

The program has been successful in managing fouling and loss of material in the high-pressure service water system, the low-pressure water system, and the service water systems, as follows: Full-flow testing has resulted in cleaning due to fouling of about two sprinkler heads at each of the transformers every 18 months. Fouling of the major header and other sprinklers has not been significant. Approximately 1/8-inch scaling has been noted on a small section of buried

8-inch pipe. This small amount of degradation has not jeopardized the systems' ability to perform their intended functions.

The staff concludes that the applicant provided information in its licensee renewal application to demonstrate that the fire water system test provides reasonable assurance that the aging effects will be managed such that the high-pressure service water system, the low-pressure water system, and the service water system will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.2.4.4 Conclusions

The staff has reviewed the information in Section 4.16, "Fire Protection," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Fire Protection Program' will adequately manage aging effects associated with structures and components that serve fire protection functions for the period of extended operation.

3.2.5 Inservice Inspection Plan

3.2.5.1 Introduction

Duke has described its inservice inspection plan in Section 4.18 of Exhibit A of the LRA. The applicant credits the examinations performed under the ASME Code, Section XI, inservice inspection program with managing the effects of aging for Class 1 components and Class 1, 2, and 3, and MC component supports during the period of extended operation. The staff has reviewed the section of the application to determine whether the applicant has demonstrated that the effects of aging will be adequately managed by the inservice inspection plan during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.5.2 Summary of Technical Information in the Application

In Section 4.18 of the LRA, the applicant has stated its intent to meet the requirements of the latest edition and addenda to the ASME Code, Section XI, that are incorporated by reference in 10 CFR 50.55a(b) for inservice inspection. These requirements are subject to the conditions specified in 10 CFR 50.55a, to the extent practical within the limitations of design, geometry, and materials of construction of the component or the support. The applicant has identified the fifth and the sixth 10-year inservice inspection intervals to cover the period of extended operation for each ONS unit. The inservice inspection plan for each of the two inservice inspection intervals will specifically address the following provisions and any other requirements of the applicable Code:

- Compliance with Appendix VII of the ASME Code, Section XI, "Qualification of Nondestructive Examination Personnel for Ultrasonic Examination"

- Compliance with Appendix VIII of the ASME Code, Section XI, "Performance Demonstration for Ultrasonic Examination Systems"

- Implementation of Subsections IWB and IWC examination requirements of either the 1989 Edition of ASME Code, Section XI, or the edition of the ASME Code, Section XI, required by 10 CFR 50.55a(b), or another edition of the ASME Code, Section XI, provided that an appropriate evaluation is performed in accordance with the regulatory requirements in effect at the time

- Compliance with 10 CFR 50.55a(g)(4)(ii) except that if an examination required by the Code or the addendum is determined to be impractical, then a relief request will be submitted to the Commission in accordance with the requirements contained in 10 CFR 50.55a(g)(5)(iv), for Commission evaluation

- Examination of pressurizer heater bundle welds in accordance with Examination Category B-E of the ASME Code, Section XI, or equivalent (see Section 4.3.7.2 of Exhibit A of the LRA)

In Section 2.4 of Exhibit A of the LRA, the applicant has identified the components in the reactor coolant system subject to an AMR and in Section 3.4, it has identified the applicable aging effects for these components (i.e., cracking, loss of material, and loss of closure integrity). The applicant credits the inservice inspections required under Subsection IWB of the ASME Code, Section XI, for Class 1 components with managing the aging effects during the period of extended operation. Table 3.4-1 of the LRA identifies the specific reactor coolant system component or component feature, the applicable aging effect, and the credited ASME Section XI examination category including other applicable inspection programs for aging management. The extent, the frequency of inspection, and the acceptance criteria for the examinations are specified in the ASME Code, Section XI, Table IWB-2500-1, for all applicable examination categories identified in Table 3.4-1 of the LRA. Components containing relevant conditions defined in the ASME Code, Section XI, Subsection IWB-3500, will be evaluated, repaired, or replaced prior to returning to service in accordance with the requirements of the Code. The applicant has provided its flaw evaluation methodology for cast austenitic stainless steel components that are susceptible to thermal embrittlement. These include valve bodies, reactor coolant pump casing and cover, and the outlet nozzle of the ONS Unit 3 reactor vessel internals. In each case, the requirement stated in the Examination Category of the ASME Code, Section XI, will be supplemented by flaw evaluation in accordance with IWB-3640.

Inservice inspection performed in accordance with ASME Code, Section XI, Subsection IWF is credited for the management of aging effects of ASME Code Class 1, 2, and 3, and MC component supports, including exposed surfaces of structural bolting, during the period of extended operation. The scope of the inspection, applicable aging effects, and the management of aging for structural components are identified in Tables 3.4-1, 3.7-1, 3.7-3, 3.7-4, 3.7-5. and 3.7-6 of the LRA. The extent, the frequency of inspection, and the acceptance criteria for the examinations are specified in the ASME Code, Section XI, Table IWF-2500-1, for all structural components.

3.2.5.3 Staff Evaluation

The staff evaluation of the Duke aging management programs focused on the program elements rather than details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of the program, (2) preventative actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

Pursuant to 10 CFR 54.21(a)(3), the applicant has proposed to use inservice inspection in accordance with the applicable ASME Code, Section XI, to manage the effects of aging in Class 1 components and Class 1, 2, 3, and MC component supports so that their intended functions will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. The scope of the inservice inspection program covers examination of safety-related components and supports that ensure (i) the integrity of the reactor coolant pressure boundary; (ii) the capability to shut down the reactor and maintain it in a safe-shutdown condition; or (iii) the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the 10 CFR Part 100 guidelines which are within the scope of license renewal. Because this is identical to the scope of license renewal in 10 CFR 54.4 for safety related SSCs, and the applicant is not relying on the ISI program to manage aging of non-safety related SSCs or SSCs covered by 10 CFR 54.4 (a)(3), the staff finds the *program scope* of inservice inspection to be acceptable.

The examinations of components under the ASME Code, Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components" performed during a 10-year inservice inspection interval, serve the following purposes:

- The volumetric, surface, or visual nondestructive examination (NDE) of components along with system pressure tests, *detect aging effects* (i.e., cracking, loss of closure integrity, and loss of material by general corrosion).

- The *parameters monitored* are specified in the ASME Code for each type of examination required. The results of examination demonstrate continuing structural integrity of the welds and the adjacent base metal, and they qualify the component for continued operation until the next required inspection — which provides for *monitoring* of the aging effects.

- The NDE results provide documentation of the "NDE signature" (e.g., geometric reflectors or acceptable flaws in the examination volume or area with current NDE technology that can be used for comparison with future inservice examination results). This provides for *trending* of the aging effects.

There are no *preventive or mitigative actions* associated with the inservice inspection program, and the staff did not identify a need for such. The operating experience with the inservice inspection program indicates that it has been successful in identifying and leading to correction of degradation effects as expected of this program.

The applicant has stated that the extent of, frequency of inspection for, and acceptance criteria for the inservice examination of components and supports complies with the requirement of the corresponding examination category in Tables IWB-2500-1 and IWF-2500-1 of the applicable ASME Code, Section XI. Furthermore, the corrective action for components and supports containing relevant conditions as defined in Subsections IWB-3500 and IWF-3122 is to evaluate, repair, or replace the item prior to returning it to service. The staff accepts the applicant's proposal for inspection in accordance with Subsections IWB and IWF of the ASME Code, Section XI, except for components for which the inspection method prescribed by the ASME Code is inadequate for detecting flaws that are smaller than the critical flaw size. In these instances, supplementary examinations or alternative acceptance criteria may be necessary. The supplementary examinations and acceptance criteria are discussed in Section 3.4 of this SER.

Therefore, this program, as supplemented by examinations of certain components discussed in Section 3.4 of this SER, demonstrates that the effects of aging will be adequately managed for all Class 1 components and Class 1, 2, and 3, and MC component supports so that their intended functions will be maintained consistent with the CLB for the period of extended operation.

3.2.5.4 Conclusion

The staff has reviewed the information in Section 4.18, "Inservice Inspection Plan," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Inservice Inspection Program' will adequately manage aging effects associated with Class 1 components and Class 1, 2, and 3, and MC component supports for the period of extended operation.

3.2.6 Inspection Program for Civil Engineering Structures and Components

3.2.6.1 Introduction

Duke described its inspection program for civil engineering structures and components in Section 4.19 of Exhibit A of the license renewal application (LRA). The program monitors and assesses the condition of structures and components affected by aging, which may cause loss of material, cracking, and change of material properties. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the aging effects on civil engineering structures and components will be adequately managed by this inspection program during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.6.2 Summary of Technical Information in Application

Section 3.4 of Exhibit A of the LRA identifies loss of material as an applicable aging effect for RCS structural components. Section 3.5 identifies loss of material as an applicable aging effect for the external surfaces of mechanical components in the reactor building, sheltered areas, and the open yard environment. Section 3.7 identifies loss of material, cracking, and change of material properties as applicable aging effects for structural components. The inspection program for civil engineering structures and components is an existing program. This program has identified unacceptable indications, which has resulted in implementation of appropriate corrective actions. Accordingly, operating experience has demonstrated that the implementation of the requirements contained in this program will be effective in managing aging during the license renewal term.

Duke indicated that it will use the inspection program for civil engineering structures and components to manage the following aging effects:

- loss of material for reactor coolant system structural components
- loss of material for the external surfaces of mechanical components in the reactor building, sheltered areas, and open yard environments
- loss of material, cracking, and change of material properties for all other ONS structural components

Scope
The scope of this program credited for license renewal is identified specifically for the structures and components in Table 3.4-1 of Exhibit A of the LRA, 3.5-1 through 3.5-12 of Exhibit A of the LRA, and 3.7-1 through 3.7-8 of Exhibit A of the LRA. For license renewal, the applicant will enhance the program to include any components identified in Table 3.4-1 of Exhibit A of the LRA, 3.5-1 through 3.5-12 of Exhibit A of the LRA, and 3.7-1 through 3.7-8 of Exhibit A of the LRA that currently are not included in the program.

Inspection Method
Each structure or component is visually inspected from the interior and exterior if accessible. Some components may be inaccessible because of radiological considerations, obstructions, or other reasons. ONS-specific characteristics, industry experience, and testing history of such components under similar environmental conditions are evaluated in lieu of actual inspection of

the inaccessible areas. If an inaccessible area becomes accessible (i.e., by excavation or other means) an inspection is performed, and the results are documented as part of the inspection program.

Teams of at least two people conduct inspections. Inspectors are qualified by appropriate training and experience and approved by responsible ONS management.

Industry Code or Standard
The inspection program follows the guidance of NEI 96-03, *Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants* (draft) for those components within the scope of 10 CFR 50.65.

Frequency
The inspection program for civil engineering structures and components will nominally be performed every five years, the exact schedule being established with consideration of refueling outages of each ONS unit. The interval may be increased to a nominal 10-year frequency with appropriate justification based on the structure, environment, and related inspection results. The inspection will be completed in phases as necessary due to the accessibility of individual structures, with the goal of completing the inspection and issuing the report within twelve months of starting the inspection.

Acceptance Criteria or Standard
The staff finds the applicant's acceptance criteria adequate because they require the evaluation of any visual indication of loss of material, cracking or change of material properties for concrete, and loss of material for steel, as identified by the accountable engineer. Inspected structures and components classified as acceptable are those structures and components that are capable of performing their intended functions and are considered to meet the requirements contained in 10 CFR 50.65(a)(2) of the maintenance rule.

Corrective Action
The accountable engineer evaluates items that do not meet the acceptance criteria for continued service, additional monitoring, or repair. Structures and components determined to be unacceptable are required to meet the provisions contained in §50.65(a)(1) of the maintenance rule. Specific corrective actions will be implemented in accordance with the Duke quality assurance program.

Administrative Controls
The Duke quality assurance program implements and controls the inspection program for civil engineering structures and components.

Operating Experience
The applicant stated that implementation of the requirements contained in the inspection program for civil engineering structures and components will be effective in managing aging

during the license renewal term in part because of the similarity with the features of the previous ONS five-year civil inspection program. The applicant considers the acceptance criteria and the frequency of the inspection program for civil engineering structures and components to be satisfactory based on recent ONS inspection results that revealed no serious degradation or conditions that would adversely affect the ability of the structures or components to perform their intended functions.

Prior to implementation of the maintenance rule and the inspection program for civil engineering structures and components, ONS had implemented a five-year civil inspection program to manage the condition of the structures and structural components deemed important to the safety and the operation of the plant. The structures that were previously inspected during the five-year civil inspection program are:

- reactor buildings
- auxiliary buildings
- radwaste facility
- standby shutdown facility
- 230 kV and 525 kV switchyard structures
- discharge structure
- intake structure
- turbine building

Previous five-year civil inspections have not noted any conditions or deficiencies that would adversely affect the ability of a structure or component to perform its intended function. Items were noted that required additional investigation, maintenance, or repair. Previous five-year civil inspections have noted findings similar to the findings from the inspection program for civil engineering structures and components. The majority of the findings were related to coatings degradation.

3.2.6.3 Staff Evaluation

The staff evaluation of the inspection program for civil engineering structures and components focused on the program elements rather than details of the specific plant procedure. The LRA includes a reference to NEI 96-03, "Industry Guideline for Monitoring the Condition of Structures 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). The acceptability of the proposed inspection program has been based on the attributes of the program as discussed below. The staff evaluated how effectively this program incorporates the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and covers all structures and components subject to aging management review. The staff evaluation of the applicant's quality assurance program is provided separately in Section 3.2.3 of this staff SER. This program satisfies the elements of "corrective actions," "confirmation process," and "administrative controls."

Program Scope
The staff finds the scope of the inspection program for civil engineering structures and components acceptable because the scope is comprehensive in that it includes a walkdown inspection of all civil structures and components affected by aging.

Preventive or Mitigative Actions
The applicant did not identify any specific preventive or mitigative activities, and the staff did not identify the need for such actions.

Parameters Inspected or Monitored
The applicant performs visual inspections on each structure or component from the interior and exterior where accessible. The applicant evaluated components that may be inaccessible because of radiological considerations, obstructions, or other reasons using ONS-specific characteristic, industry experience, and testing history of such components under similar environmental conditions. Whenever normally inaccessible areas become accessible (i.e., by excavation or other means), an inspection is performed. 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
As discussed above, the staff found the inspection technique of the inspection program for civil engineering structures and components acceptable for detection of the applicable aging effects. With respect to inspection frequency, the applicant stated that the inspections will be performed every five years. The applicant's operating experience to date supports the continuation of such a frequency. The staff finds that the five-year frequency is consistent with industry experience and is, therefore, acceptable. The applicants has also stated that the frequency of inspection may be reduced to a nominal 10 years with appropriate justification based on the structure, environment and related inspection results. Since the change to frequency of inspection is controlled by quality assurance requirements based on Appendix B to 10 CFR Part 50, there is reasonable assurance that proposed changes will be subject to an adequate approval process that the plant has in place. The staff finds that the proposed inspection techniques and the associated frequencies are consistent with industry experience and are, therefore, acceptable.

Monitoring and Trending
There are no monitoring and trending processes associated with the inspection program for civil engineering structures and components, and the staff did not identify a need for such.

Acceptance Criteria
The staff finds the applicant's acceptance criteria adequate because they require the evaluation of any visual indication of loss of material, cracking or change of material properties for concrete, and loss of material for steel identified by the accountable engineer. The applicant also indicated that all inspected structures and components will meet the requirements contained in 10 CFR 50.65(a)(2) of the maintenance rule.

Operating Experience
The inspection program for civil engineering structures and components is an existing program at ONS. The recent inspection results revealed no serious degradation or conditions that would adversely affect the ability of the structures or components to perform their intended functions. Previous inspection findings were mainly related to coatings degradation. The staff finds that the applicant's operating experience has demonstrated that the inspection program for civil engineering structures and components has effectively maintained the integrity of civil structures and components and will be effective for license renewal, as well.

3.2.6.4 Conclusions

The staff has reviewed the information in Section 4.19, "Inspection Program for Civil Engineering Structures and Components," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the "Inspection Program for Civil Engineering Structures and Components" will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

3.2.7 Reactor Coolant System Operational Leakage Monitoring

3.2.7.1 Introduction

Duke described its aging management review (AMR) of its reactor coolant system operational leakage monitoring in Section 4.23 of the license renewal application (LRA). The applicant credits this program with managing aging effects for the reactor coolant system (RCS), for specific heat exchangers in the high-pressure injection system (HPIS), and for the component cooling system (CCS). This program, in conjunction with the applicant's other aging management programs, such as Improved Technical Specification 3.4.13, the inservice inspection program, and the chemistry control program, manages cracking, loss of material, and loss of closure integrity. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the operational leakage monitoring for aging effects on the reactor coolant system will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.7.2 Summary of Technical Information in the Application

In Section 4.23 of Exhibit A of the LRA, the applicant describes monitoring activity that, in part, manages aging effects due to cracking, loss of material, and loss of closure integrity. The monitoring activity verifies the continuing capability of the RCS, HPIS, and CCS to perform their intended functions (i.e., maintain system pressure boundary integrity) under all current licensing basis (CLB) conditions for the period of extended operation. The applicant identified several components within the RCS that rely on this program, including the RCS piping, pressurizer, reactor vessel, steam generators, control rod drive tube motor housings, and letdown coolers. The applicant identified that the reactor coolant pump (RCP) coolers (Units 2 and 3 only), the RCP seal return coolers within the HPIS, and the quench tank coolers rely on this program. The applicant stated that the quench tank coolers within the CCS also rely on this program.

3.2.7.3 Staff Evaluation

The staff evaluation of the reactor coolant system operational leakage monitoring focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to aging management review. The staff evaluation of the applicant's quality assurance program is provided separately in Section 3.2.3 of this staff SER. This program satisfies the elements of corrective actions, confirmation process, and administrative controls.

Program Scope
The program monitors RCS inventory (the HPIS is contiguous with the RCS when in operation) to identify degraded conditions of the RCS pressure boundary. The scope of the program includes the Class 1 portions of the RCS, Class 1 portions of the HPIS, the letdown coolers, the RCP coolers found on ONS Units 2 and 3, the RCP seal return coolers on all three ONS units, and the CCS quench tank coolers. The applicant relies primarily on a combination of chemistry controls and inservice inspections to manage most aging effects applicable to large-diameter (i.e., greater than 4-inch-diameter) RCS piping and other RCS components such as the RCP casing. Although not explicitly credited by the applicant in the LRA, the staff considers the RCS operational leakage monitoring program will also manage, in part, aging effects of these components. Thus, the staff finds the scope of the reactor coolant system operational leakage monitoring 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.

Parameters Inspected or Monitored
The applicant describes how it monitors RCS inventory in the Bases section of its technical specification (TS), "RCS Operational Leakage"; specifically, in the surveillance requirements Section 3.4.13.1. The applicant performs an RCS water inventory balance to measure RCS leakage. The applicant monitors and measures primary to secondary leakage through effluent monitoring in the secondary systems or by comparison of primary and secondary radioisotope concentrations. The applicant performs the RCS water inventory balance with the reactor at steady state operating conditions. The applicant relies on the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level to provide an early warning of RCS leakage. The applicant specifies these leakage detection systems in its TS 3.4.15, "RCS Leakage Detection Instrumentation." The staff finds the parameters monitored acceptable because (1) RCS water inventory balance, containment atmosphere radioactivity, containment sump levels, and quench tank levels provide direct evidence of RCS leakage, and (2) these parameters are in accordance with the applicant's technical specifications, which the staff previously approved.

Detection of Aging Effects
The applicant performs RCS inventory monitoring 12 hours after achieving steady state plant conditions and thereafter performs RCS inventory monitoring every 72 hours, in accordance with its TS 2.4.13. To provide for early warning of leakage, the applicant relies on its containment air monitoring of radioactivity and the containment sump level monitoring. In response to RAI 4.23-4, the applicant stated that it continuously performs air monitoring and containment sump level monitoring. To monitor its primary-to-secondary leakage through steam generator tubes, the applicant relies on effluent monitoring in the secondary systems or a comparison of primary and secondary radioisotope concentrations. Effluent monitoring is performed continuously using radiation monitors installed in the air ejectors of each main condenser. As discussed earlier, the staff finds the parameters monitored in this program acceptable. The staff finds the frequency of monitoring acceptable because it is consistent with the applicant's technical specifications, industry practice, and staff expectations.

The staff finds that the combination of acceptable scope, parameters, and frequency can be relied upon to detect aging effects before there is a loss of intended function.

Monitoring and Trending
The applicant detects, monitors, and trends RCS leakage. The staff finds this aspect acceptable in that the trending provides advance warning to permit unit shutdown or prompts other corrective action before there is a loss of intended function.

Acceptance Criteria
The acceptance criteria are specified in the ONS Improved Technical Specification 3.4.13. These include limits on unidentified and identified leakage as well as primary-to-secondary steam generator tube leakage. The staff finds the acceptance criteria acceptable because they are consistent with the applicant's technical specifications.

Operating Experience
The applicant discussed ONS-specific operating experience with both RCS and HPIS leakage identified through the use of the RCS operational leakage monitoring. The applicant stated that specific examples of cracking, loss of material, or loss of mechanical closure integrity that resulted in RCS leakage in excess of technical specification leakage limits included: (1) a nonisolable leak at the pressurizer drain line weld in 1998, (2) a nonisolable leak at the weld that connects the HPIS branch connection to the safe end in 1997, (3) a once through steam generator tube leak in 1988, and (4) valve-packing failures in 1995 and 1985 that resulted in leakage at bolted closures. The applicant confirmed that the reactor coolant system operational leakage monitoring detected the leakage and allowed for timely corrective actions for each of these examples. The staff finds that the applicant's operating experience supports the attributes of its program.

3.2.7.4 Conclusions

The staff has reviewed the information in Section 4.23, "Reactor Coolant System Operational Leakage Monitoring," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Reactor Coolant System Operational Leakage Monitoring' program will adequately manage aging effects associated with the RCS, HPIS, and CCS for the period of extended operation.

3.2.8 Cast Iron Selective Leaching Inspection

3.2.8.1 Introduction

Duke described its aging management review (AMR) of a new program of cast iron selective leaching inspection in Section 4.3.2 of the license renewal application (LRA). The program aims to verify integrity of the components made of cast iron and exposed to water environments that may cause selective leaching of ferrite phase (graphitic corrosion). The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging on cast iron components will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.8.2 Summary of Technical Information in the Application

Section 4.3.2 of Exhibit A of the LRA describes a new program that the applicant intends to implement for determining acceptability of the cast iron components exposed to selective leaching in raw water, treated water, and ground water environments. These types of environments exist in the ONS and affect cast iron components in the following systems: auxiliary service water system, high-pressure service water system, condenser circulating water system, condensate system, and service water system in the Keowee plant.

The proposed cast iron selective leaching inspection program will provide a one-time inspection of the affected components. It will consist of inspecting a selected set of cast iron pump casings to determine whether loss of material due to selective leaching is occurring and whether it will cause concern for the period of extended operation. Brinnell Hardness checks will be used to determine if the phenomenon is occurring, and if it is, an engineering evaluation will be initiated to determine acceptability of the affected components for further service.

Section 5, "Time-Limited Aging Analyses and Exemptions Review," of Exhibit A of the LRA indicates that there are no time-related aging analyses (TLAAs) for the cast iron components exposed to selective leaching in water environments.

3.2.8.3 Staff Evaluation

The staff evaluation of the Duke aging management programs related to the cast iron selective leaching inspection focused on the program elements rather than details of specific plant procedures. To determine whether these programs are adequate for managing the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements applicable to this program: scope of the program, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation processes, administrative controls and operating experience.

The application indicates that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of the SER. Thus, these elements will not be discussed further in this section.

In this program, Duke will determine acceptability of the components exposed to selective leaching for service during the extended period of operation. This will be achieved by inspecting four pump casings which are most prone to selective leaching, one from each of the following systems: auxiliary service water system, high-pressure service water system, service water system (Keowee plant), and condensate system (one inspection location on any of the three ONS Units) (*Scope of Program*). The inspection program will be performed only once. With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable. If present, cast iron selective leaching is a slow acting corrosion mechanism; thus, the staff expects minimal corrosion, if any, and finds the use of a one-time inspection adequate.

Duke will perform Brinell Hardness testing on the inside surfaces of the selected set of cast iron pump casings to determine if selective leaching has occurred (*Detection of Aging Effects).* Identification of the selective leaching by the test will constitute the need for further engineering evaluation before the affected components could be qualified for further service (*Acceptance Criteria*). This evaluation will be performed under the plant's Problem Investigation Process, and if necessary will include a root cause analysis.

In the cast iron selective inspection program, there is no *monitoring and trending,* and the staff did not identify a need for such. Since this is a new program, *operating experience* does not exist.

3.2.8.4 Conclusions

The staff has reviewed the information in Section 4.3.2, "Cast Iron Selective Leaching Inspection," of Exhibit A of the LRA. On the basis of this review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Cast Iron Selective Leaching Inspection' program will adequately verify that there is no need to manage aging effects associated with components made of cast iron and exposed to water environments that may cause selective leaching of ferrite phase (graphitic corrosion) or otherwise take appropriate corrective actions for the period of extended operation.

3.2.9 Galvanic Susceptibility Inspection

3.2.9.1 Introduction

Duke described its aging management review (AMR) of a new program of galvanic susceptibility inspection in Section 4.3.3 of the license renewal application (LRA). The program is aimed at verifying integrity of the components subjected to galvanic corrosion. The staff reviewed this section of the application to determine whether the applicant has 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).

3.2.9.2 Summary of Technical Information in the Application

Section 4.3.3 of Exhibit A of the LRA, describes a new program the applicant intends to implement for determining acceptability of the components exposed to galvanic corrosion. This type of corrosion occurs when components are made of materials that are far apart in galvanic series, are coupled, and exposed to corrosive environments. In this situation a less-noble component will corrode. Duke identified three types of galvanic couples at the ONS: carbon steel-stainless steel, carbon steel-copper alloy, and copper alloy-stainless steel. Galvanic corrosion could occur in the following systems containing corrosive environments: auxiliary service water system, condensate system, portion of condenser, high-pressure service water system, low-pressure service water system, low-pressure injection system, and standby shutdown facility auxiliary service water system. It also could occur in the service water system, the turbine generator cooling water system, and the turbine sump pump system in the Keowee plant. The aging effect due to galvanic corrosion consists of material loss by the less-noble material in the galvanic couple.

The applicant's galvanic susceptibility inspection program is a one-time inspection program that will volumetrically examine a representative sample of the components most susceptible to galvanic corrosion. Thus, the program will be limited to inspecting only carbon steel-stainless steel couples in areas of low to stagnant flow of raw water, where a higher rate of galvanic corrosion of carbon steel is expected due to the large difference in the galvanic series for these metals. If the applicant detects significant damage to the affected components, it will implement corrective actions in accordance with the Duke quality assurance program.

3.2.9.3 Staff Evaluation

The staff evaluation of the Duke aging management programs related to galvanic susceptibility inspection focused on the program elements rather than details of specific plant procedures. To determine whether these programs are adequate for mitigating the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements applicable to this program: scope of the program, preventive or mitigative actions, parameters monitored or inspected, monitoring and trending, detection of aging effects, acceptance criteria, corrective actions, confirmation processes, administrative controls, and operating experience.

The application indicates that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's corrective action program is presented separately in Section 3.2.3 of the SER. Thus, these three elements will not be discussed further in this section.

There are no activities in the galvanic susceptibility inspection program for *preventive or mitigative* actions, or for *monitoring and trending.* The staff did not identify the need for such.

Duke conducted a review of more than 200 metallurgical inspection records for the ONS dated from 1981, and it found no component failures caused by galvanic corrosion (*Operating Experience*). However, because of the possibility of this type of corrosion, it established a one-time inspection program. In this program, Duke will determine acceptability of the components subjected to galvanic corrosion for service during the extended period of operation. This determination will be achieved by performing inspection of selected components. The sample will purposely contain components expected to be exposed to the highest rates of galvanic corrosion. It will be selected for this inspection from the following raw water systems within the scope of license renewal: auxiliary service water system, raw water portions of the condensate cooler and main condenser systems, condenser circulating water system, high-pressure service water system, low-pressure injection system, component cooling system (component coolers), low-pressure service water system, service water system, turbine generator cooling water system and turbine sump pump system in the Keowee plant (*Scope of Program*). The sample will consist of carbon steel components coupled with the components made from stainless steel. Since these materials are the farthest apart on the galvanic series, the highest galvanic corrosion will be expected. The wall thickness inspection of the representative sample will determine loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the components in the portion of the plant included in the LRA (*Parameter Inspected and Detection of Aging Effects*). The acceptance criterion is based on component wall thickness permitted by ONS component design code of record (*Acceptance Criteria*). The staff finds this approach acceptable because it bounds galvanic corrosion rates occurring in other components in the plant and therefore, provides meaningful detection of age-related damage caused by galvanic corrosion. As noted above, the inspection program will be performed once. With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable. If present, galvanic corrosion is expected to be a slow acting corrosion mechanism for the affected components in these systems; thus, the staff finds the use of a one-time inspection adequate.

The program also includes a description of the activities undertaken if significant component damage is detected. The staff finds that, as proposed by the applicant, engineering analysis followed by implementation of specific corrective actions specified in the Duke quality assurance program provide satisfactory management of the aging effects caused by galvanic corrosion.

3.2.9.4 Conclusions

The staff has reviewed the information in Section 4.3.3, "Galvanic Susceptibility Inspection," of Exhibit A of the LRA. On the basis of this review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Galvanic Susceptibility Inspection' program will adequately manage aging effects associated with components subjected to galvanic corrosion for the period of extended operation.

3.2.10 Preventive Maintenance Activities

3.2.10.1 Introduction

Duke described its aging management review (AMR) of preventive maintenance activity assessment in Section 4.3.8 of the license renewal application (LRA), as supplemented by its

September 30, 1999 and October 15, 1999 submittals. The applicant credits various maintenance activities with managing aging effects for a variety of systems. The affected systems include the low-pressure injection system, the low-pressure service water system, the condensate system, the condenser circulating water system, the reactor building cooling system, the standby shutdown facility (SSF) diesel generator fuel oil system, the Keowee hydroelectric station turbine generator cooling water system, and the SSF heating, ventilation, and air conditioning (HVAC) system. The staff reviewed the application to determine whether the applicant has demonstrated that the preventive maintenance (PM) activities will adequately manage aging effects during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.10.2 Summary of Technical Information in the Application

In Section 4.3.8 of Exhibit A of the LRA, the applicant describes a new program that assesses the effectiveness of various PM activities. The applicant relies on these PM activities to manage aging effects and to ensure that the component-intended functions are being maintained under all current licensing basis (CLB) conditions for the period of extended operation. The PM activity assessment is a one-time assessment performed in accordance with the applicant's quality assurance program (discussed in Section 3.2.3 of this safety evaluation report). The assessment will be completed by February 6, 2013 (the end of the initial license of ONS Unit 1). If the assessment determines that enhancements to one or more PM activities are needed, the applicant will implement appropriate corrective actions. The PM activities are described below.

Borated Water Storage Tank Internal Coatings Inspection and Decay Heat Cooler Tubing Examination

The low-pressure injection system removes decay heat during cold shutdown and refueling operations. Upon initiation of an accident, the system takes suction from the borated water storage tank and injects the tank contents into the reactor vessel. The borated water storage tank is made from carbon steel with an epoxy-phenolic coating. The internal environment is primarily borated water, and the upper portion of the tank is exposed to air. To manage loss of material due to corrosion of the internal surfaces of the tank, the applicant relies primarily on the protective plastic lining. The applicant credits its borated water storage tank internal coatings inspection with ensuring that the lining is intact and in good condition. The inspection consists of a visual examination of the lining to identify any coating failures. The applicant performs the inspection every third refueling outage after removing the borated water from the tank. The applicant implements corrective actions consistent with its quality assurance program for any indication of a coating defect.

The decay heat coolers of the low-pressure injection system are exposed to borated water through the tubes, and raw water in the shell and on the outer surface of the tubes. The shell of the decay heat coolers is made from carbon steel, and all other components are made of stainless steel. To manage loss of material due to corrosion of the stainless steel tubes, the applicant credits its decay heat cooler tubing examination. The examination consists of a 100%

eddy current inspection of the stainless steel heat exchanger tubes to identify degraded conditions. The applicant performs the inspection every fourth refueling outage. The applicant plugs all tubes with wall loss indications of greater than 60% throughwall.

Component Cooler Tubing Examination
The low-pressure service water system provides cooling water to a variety of safety-related components in the plant. The component coolers within the system are exposed to raw water through the tubes and treated water on the outer surface of the tubes. The component cooler tubes are made from admiralty brass. To manage loss of material due to corrosion of the tubes, the applicant credits its component cooler tubing examination. The tubing examination consists of a 100% eddy current inspection of the heat exchanger tubes to identify degraded conditions. The applicant performs the inspection every other refueling outage. The applicant evaluates all tubes with wall loss measured at greater than 60% throughwall to justify continuing service or plugging the tubes.

Main Condenser and Condensate Cooler Tubing Examination
The condensate system delivers condensate from the condenser hotwell to the suction of the main feedwater pumps, purifies the condensate, removes noncondensable gases from the condensate, and heats the condensate to improve plant efficiency. The system also supplies water to the emergency feedwater pumps during emergency operation. The main condenser and condensate coolers are exposed to raw water through the tubes and treated water in the shell and on the outer surface of the tubes. The tubes of the main condenser and the condensate coolers are made of stainless steel. To manage loss of material due to corrosion of the tubes, the applicant credits its "main condenser tubing examination" and its "condensate cooler tubing examination." The main condenser examination consists of eddy current inspections of 10% of the tubes in one-half of the condenser each refueling outage. Tubes in each half of the condenser are examined every other refueling outage. The condensate cooler examination consists of eddy current inspections of the most susceptible tubes (those along the perimeter and those at the baffle regions — approximately 25% of the tubes) every third refueling outage. For both examinations, the applicant evaluates all tubes with wall loss measured at greater than 60% throughwall to justify continuing service or plugging the tubes.

Condenser Circulating Water System Internal Coatings Inspection
The condenser circulating water system uses lake water as the ultimate heat sink during normal operation and for decay heat removal during plant cool down. The system also provides cooling water to certain plant equipment and is the suction source for other service water systems. The piping of this system is made from carbon steel lined with a coal tar epoxy, and it is exposed to raw water. To manage loss of material due to corrosion of the internal surfaces of the piping, the licensee relies primarily on the protective lining. To ensure the lining is intact and in good condition, the licensee credits its condenser circulating water system internal coatings inspection. The inspection consists of a visual examination of the large-diameter condenser circulating water system underground piping to detect degradation of the protective lining. This inspection provides indications of the condition of the piping, including symptomatic evidence of

the condition of the pipe's external surface. The applicant inspects the interior surface of the underground intake and discharge piping every five years. The applicant implements corrective actions consistent with its quality assurance program for any indication of a lining defect.

Reactor Building Cooling Unit Tubing Inspection
The reactor building cooling system provides cooling to the reactor building during both normal plant operation and following a loss-of-coolant accident. The cooling units of this system transfer heat from the containment atmosphere to the low-pressure service water system. The cooling units are exposed to raw water through the tubes and to ventilation air through the ducts and on the outer surface of the tubes. The duct work is constructed of aluminum, galvanized steel, and stainless steel. The tubes are made of 90-10 copper-nickel, the tube fins are made from copper, and the headers are made of stainless steel. To manage loss of material due to corrosion, the applicant credits its reactor building cooling unit tubing inspection. The inspection consists of rodding out the tubes followed by a visual inspection of the tubes, duct work, and internal supports to assess their condition. The applicant performs the waterside procedure (tube rodding) every refueling or as required by performance testing. The applicant performs the airside procedure (inspections of the duct work and internals supports) as required by performance testing. Heat exchanger performance testing is described in Section 3.2.12 of this SER. The applicant implements corrective actions consistent with its quality assurance plan if there is any indication of degradation.

Standby Shutdown Facility Diesel Fuel Oil Tank Inspection
The standby shutdown facility (SSF) diesel generator fuel oil system supplies fuel oil to each diesel engine injector for combustion and fuel injector cooling. The underground fuel oil tank of this system is made from coated carbon steel. The internal environment is exposed to fuel oil; however, the tops of the carbon steel tanks are open to the atmosphere. The external surface of the tank is exposed to soil and groundwater. To manage loss of material due to corrosion of the internal and external surfaces of the tank, the applicant relies on the protective coating. To ensure that the interior and exterior coatings are intact and in good condition, the licensee credits its standby shutdown facility diesel fuel oil tank inspection. The inspection consists of a visual examination of the tank interior after the fuel oil is removed. The applicant performs this inspection every ten years. The applicant implements corrective actions consistent with its quality assurance plan if there is any indication of coating degradation. For obvious practical reasons, there are no inspections of the exterior surface of the underground tank.

Turbine Generator Cooling Water System Strainer Inspection
The turbine generator cooling water system is part of the Keowee hydroelectric station. This part of the system provides cooling water to the turbine packing box, generator thrust bearing coolers, generator air coolers, and turbine guide bearing oil coolers, as well as back up cooling to other unit loads. Strainers in this system are made from carbon or stainless steel and are exposed to raw water. To manage loss of material due to corrosion of the strainers of the turbine packing box cooling water and the main inlet, the applicant credits its turbine generator cooling water system strainer inspection. The inspection consists of cleaning and performing a

visual examination of the strainers. The applicant performs this inspection on the turbine packing box cooling water strainer weekly and on the main inlet strainer bimonthly. The applicant implements corrective actions consistent with its quality assurance plan if there is any indication of degradation.

SSF HVAC Coolers Preventive Maintenance Activity
The SSF HVAC system maintains the SSF environment within a predetermined temperature range to support equipment operability. The HVAC system contains one heat exchanger that is within the scope of license renewal. The unit consists of air-cooling coils and a water-cooled condenser. The air-cooling coils transfer heat from the supply air in the SSF to the refrigerant while the water-cooled condenser rejects the heat from the refrigerant to the SSF auxiliary service water system. To manage loss of material due to corrosion of the various components of the cooling coils and condenser, the applicant credits its SSF HVAC preventive maintenance activity. The activity consists of measuring the heat transfer parameters (the inlet and outlet temperatures) of the HVAC system and visually inspecting the air-cooling coils (specifically the aluminum fins). This activity is performed on a semi-annual basis. The applicant implements its corrective actions consistent with its quality assurance plan if there is a loss of cooling capacity or if there are indications of loss of material of the air-cooling coils.

Reactor Building Auxiliary Cooler Inspection
The low pressure service water system provides cooling water to a variety of safety-related components in the plants. The reactor building auxiliary coolers within the system provide cooling to the upper portions of the Oconee reactor buildings. The coolers are exposed to raw water through the tubes and ventilation air on the outer surface of the tubes. The reactor building auxiliary coolers have copper tubes and stainless steel headers. To manage loss of material due to corrosion of the tubes, the applicant credits its reactor building auxiliary cooler inspection. The inspection consists of a pressure test and visual inspection to look for leaks. The applicant tests and inspects one of four tube bundles in each plant each refueling outage, rotating the inspection among the four bundles. The applicant evaluates any leakage or indication of material loss to justify continuing service or plugging the tubes.

3.2.10.3 Staff Evaluation

In its October 29, 1998, request for additional information (RAI), the staff requested that the applicant clarify the intent of the program and explain how it differs from the applicant's quality assurance program. The staff also requested that the applicant provide a description of the PM activities and suggested that it consider the activities as programs unto themselves. In its response dated December 14, 1998, the applicant agreed to consider the PM activities as stand-alone aging management programs for license renewal. Duke stated that the PM activities described in Section 4.3.8 of the LRA met most of the attributes of stand-alone aging management programs except that the programs lacked sufficient documentation to demonstrate the effectiveness of these activities. Thus, Duke initially intended to assess each of these PM activities against the attributes of a successful program listed in Section 4.2 of the

LRA, document and analyze the results, and demonstrate that the activities adequately manage the effects of aging so that the intended functions of the structures and components will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. This assessment was to be a distinct part of the current ONS self-assessment process. In response to RAI 4.3.8-8, the applicant withdrew its plans to perform a one-time assessment of the PM activities. Duke stated that the ongoing inclusion of these programs in its quality assurance program ensures the PM activities are effective in managing aging.

The applicant's successful operating experience to date using these PM activities provides reasonable assurance that these PM activities, which have been performed for most of the affected systems for more than a decade, will continue to be effective through the period of extended operation. If conditions adverse to quality are identified, including identification that aging effects are not being effectively managed by these PM activities, the applicant will implement its quality assurance program regardless of the status of the PM activity assessment program. As documented in a meeting summary dated April 7, 1999, the applicant confirmed that the results of the PM activities have been and will continue to be assessed to ensure the activities provide adequate management of aging effects. Thus, the staff finds the applicant's withdrawal of performing a one-time assessment acceptable.

The staff evaluation of the preventive maintenance activities focused on the specific PM activities and how they manage aging effects. The staff evaluated how effectively the PM activities incorporate the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions and confirmation process for license renewal are in accordance with the site-controlled quality assurance plan pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to aging management review. For administrative controls, the applicant provided its description of the specific controls for each PM activity, and these in turn will be included in the applicant's description of the PM activities in the UFSAR supplement. The staff finds this provides reasonable assurance that the "administrative controls" element is met for these PM activities. The staff evaluation of the applicant's quality assurance plan is provided separately in Section 3.2.3 of this staff Safety Evaluation Report. This program satisfies the elements of "corrective actions," "confirmation process," and "administrative controls." Thus, these three elements will not be discussed further in this section.

Program Scope
The applicant clearly defined the purpose and the scope of each PM activity. The scope of the inspections appears adequate because the sample size inspected during these activities usually consists of a 100% sample. For two activities (main condenser and condensate cooler tubing examination), the sample size is less than 100%. However, the staff concludes the sample size

is large enough to detect degradation significant enough to trigger an inspection scope expansion (or other corrective actions deemed appropriate by the applicant). For one activity (condenser circulating water system internal coatings inspection), the applicant inspects specific locations deemed either bounding or representative of the remainder of the system. The staff finds this approach practical and reasonable to detect significant degradation that may indicate a more generic problem to be addressed by expanded inspections.

Preventive or Mitigative Actions
There are no preventive or mitigative actions taken as part of these PM activities, and the staff did not identify the need for such.

Parameters Inspected or Monitored
For most of the PM activities, the parameters inspected are eddy current indications of wall loss. For other PM activities, the parameters inspected are direct indications of corrosion (e.g., rust, pits, and wall loss) or coating defects (e.g., holidays, and scratches). One activity also measures heat transfer parameters. The staff finds these parameters and their associated techniques acceptable because they are considered standard for this type of application and proven to be effective.

Detection of Aging Effects
The applicant performs these activities using written procedures, documented instructions, or drawings that conform to applicable codes, standards, specifications, and criteria. The scope and technique applied for these activities were discussed above and found to be acceptable. The frequencies for performing the PM activities depend on the type of component and on its degree of exposure to the damaging environment. Because the applicant has been performing most of these PM activities for more than a decade and has found no indication that the activities are ineffective, the staff finds the frequency at which the applicant performs the PM activities to be acceptable. Taken as a whole, the staff finds that the PM activities' scope, inspection technique, and inspection frequency provide reasonable assurance that aging effects will be detected before there is a loss of component-intended function.

Monitoring and Trending
There are no monitoring or trending actions taken as part of these PM activities, and the staff did not identify the need for such.

Acceptance Criteria
For those PM activities including a visual inspection, the applicant stated that it will evaluate all indications of degradation. The staff finds this acceptable. For the one PM activity that measures heat transfer parameters, the applicant stated that it will compare the values with the required heat transfer capacity of the system and evaluate any indication of degraded heat transfer capacity. The staff finds this acceptable. For those PM activities including an eddy current test, the applicant stated that it will evaluate all indications greater than 60% throughwall.

In response to RAI 4.3.8-7, the applicant stated that the 60% throughwall criterion for the decay heat removal coolers was based on the minimum wall thickness required to meet ASME Code requirements under the most severe loading conditions deemed possible. For the component coolers, condensate coolers, and main condenser coolers, the applicant stated that a rigorous calculation was not available. For these non-safety-related heat exchangers, the applicant follows industry practice that considers 60% wall loss a conservative standard for taking corrective action. The staff finds the applicant's acceptance criteria for eddy current testing of heat exchanger tubes reasonable because they are conservatively based on a combination of Code requirements and industry practice.

Operating Experience
The applicant has been performing most of these PM activities for over a decade and has not found any indication of ineffectiveness. The applicant has incorporated operating experience in its PM activities on an as-needed basis, as part of its quality assurance program. Thus, the staff finds the operating experience supports the attributes of the PM activities.

3.2.10.4 Conclusions

The staff has reviewed the information in Section 4.3.8, "Preventive Maintenance Activity Assessment," of Exhibit A of the LRA, as supplemented by submittals dated September 30, 1999 and October 15, 1999. On the basis of this review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Preventive Maintenance Activity Assessment' will adequately manage aging effects associated with the auxiliary service water system, the low-pressure injection system, the low-pressure service water system, the condensate system, the condenser circulating water system, the reactor building cooling system, the SSF diesel generator fuel oil system, the Keowee hydroelectric station turbine generator cooling water system, and the SSF HVAC system for the period of extended operation.

3.2.11 Treated Water Systems Stainless Steel Inspection

3.2.11.1 Introduction

Duke described its aging management review (AMR) of its inspection program for stainless steel components of treated water systems in Section 2.5 of Exhibit A of the LRA. The section identifies the stainless steel mechanical components in the chemical addition, component cooling, demineralized water, filtered water, liquid waste disposal, safe shutdown facility (SSF) drinking water, and SSF sanitary lift systems. Section 3.5 of the application identifies loss of material and cracking as the applicable aging effects for the stainless steel components in these systems.

Components of the filtered water system are exposed to filtered water. Filtered water is water that has been processed to remove particles and impurities.

Aging Management Review

The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging of stainless steel treated water system components will be adequately managed by this program during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.11.2 Summary of Technical Information in the Application

The applicant determined that for all components subject to pitting corrosion and stress corrosion, those aging effects are to be managed for license renewal. The applicant is planning an inspection of a select set of stainless steel piping locations to determine whether there has been loss of material due to pitting corrosion and cracking from stress corrosion and whether further programmatic aging management will be required to manage these effects for license renewal. The applicant has stated that until the time of application, it has found no evidence to confirm that these aging effects are applicable to these systems, and no industry experience has identified such effects in stainless steel components in these types of systems.

The purpose of the treated water systems stainless steel inspection program will be to characterize the loss of material from pitting corrosion and stress corrosion that could occur within the systems identified above. The results of the inspection will be applied to the stainless steel piping and valves in portions of several treated water systems that are exposed to treated or potable water falling under guidelines separate from those of the chemistry control program. The focus of this inspection will be to inspect a representative sample from each of the seven treated water groups identified in the list below. The results of the inspections in each group will indicate the condition of all of the stainless steel components in the systems within that group. The systems containing the stainless steel piping and valves under consideration for inspection are:

- chemical addition system (caustic addition portion containing demineralized water)
- component cooling system (the stainless steel containment penetration portion on Unit 2 only containing demineralized water)
- demineralized water system (containment penetration portion containing demineralized water)
- filtered water system (containment penetration portion containing filtered water)
- liquid waste disposal system (containment penetration portion containing demineralized water)
- SSF drinking water system (containing potable water)
- SSF sanitary lift system (containing potable water)

3.2.11.3 Staff Evaluation

The staff evaluated the treated water system stainless steel inspection program in order to determine the adequacy of the program to manage the aging effects of loss of material from pitting corrosion and stress cracking corrosion.

The application indicated that the treated water systems stainless steel inspection program for license renewal is part of the site-controlled quality assurance program. The program meets the requirements of 10 CFR Part 50, Appendix B, and covers all structures and components subject to an AMR. Compliance with the requirements of 10 CFR Part 50, Appendix B provides adequate assurance that quality and safety will be maintained. The staff evaluation of the applicant's quality assurance program is provided separately in Section 3.2.3 of this staff safety evaluation report.

Program Scope
The filtered water system includes three containment penetrations within its scope. Since the filtered water system has no parameters that would distinguish among the three containment penetrations, one of the three containment penetrations will be selected for inspection. A stainless steel weld at one containment isolation valve, along with piping and a weld between the isolation valve and the containment penetration schedule transition point, will be volumetrically examined in the 6-inch nominal pipe size stainless steel piping. In addition, one valve will be disassembled for an internal visual examination.

The demineralized water system includes four containment penetrations within its scope. Because the demineralized water system has no parameters that would distinguish among the four containment penetrations, one of the three 4-inch nominal pipe size containment penetrations will be selected for inspection. A stainless steel weld at one containment isolation valve, along with piping and a weld between the isolation valve and the containment penetration schedule transition point, will be volumetrically examined. In addition, one valve will be disassembled for an internal visual examination.

In the SSF drinking water system, a 1-foot section of 1-inch nominal pipe size piping will be volumetrically examined upstream of valve PDW-72. In addition, one valve will be disassembled for an internal visual inspection.

The staff considers the program scope adequate to verify whether stainless steel is experiencing pitting corrosion or cracking in the treated water systems. This is based on adequate sampling and inspection of stainless steel components to assess the system.

Preventive or Mitigative Actions
Based on the results of these inspections, if loss of material from pitting corrosion or stress corrosion cracking is occurring, the applicant will undertake further programmatic actions, such as repair and replacement, as necessary, to manage these aging effects.

Parameters Inspected or Monitored and Detection of Aging Effects
The applicant will perform a volumetric examination of various susceptible piping locations. This examination will include a stainless steel weld and heat-affected zone since these are the likely location for stress corrosion cracking to occur. The use of volumetric examinations, which evaluates the full volume of the piping, will ensure that unacceptable pipe flaws will be identified.

In addition to the volumetric examination, the applicant will visually examine the interior of a valve to determine the presence of pitting corrosion. To identify pitting or cracking, Duke will inspect portions of stainless steel piping and valves, as applicable, for each of the three groups of system components. The treated water systems stainless steel inspection will be performed only once. With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable. If present, pitting or cracking of stainless steel in the treated water systems would be slow acting mechanisms; thus, the staff expects minimal pitting or cracking, if any, and finds the use of a one-time inspection acceptable.

Monitoring and Trending
The applicant did not describe any activities for monitoring and trending aging effects in these systems, and the staff did not identify any need for such.

Acceptance Criteria
The acceptance criteria for the above mentioned inspections specifies minimum design wall thickness and maximum crack and flaw size. Indication of loss of material from pitting corrosion or cracking from stress corrosion not meeting these specified criteria as determined by engineering analysis, will not be accepted. Any unacceptable loss of material from pitting corrosion or stress corrosion cracking requires an engineering analysis to determine potential impact on component intended function. Specific corrective actions will be implemented in accordance with the Duke quality assurance program.

Operating Experience
The applicant has stated that until the time of application, no evidence has been found to confirm that these aging effects are applicable to these systems, and no industry experience has identified such effects on stainless steel components in these types of systems.

In view of this operating experience, the NRC staff finds the treated water systems stainless steel inspection program acceptable because the program will verify whether pitting and stress corrosion cracking are occurring in ONS treated water systems. If pitting and stress corrosion cracking are detected, the affected components will be repaired or replaced.

3.2.11.4 Conclusions

The staff has reviewed the information in Section 4.3.13, "Treated Water Systems Stainless Steel Inspection," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Treated Water Systems Stainless Steel Inspection' program will adequately manage aging effects associated with stainless steel mechanical components in the chemical addition, component cooling, demineralized water, filtered water, liquid waste disposal, safe shutdown facility (SSF) drinking water, and SSF sanitary lift systems for the period of extended operation.

3.2.12 Heat Exchanger Performance Testing Activities

3.2.12.1 Introduction

Duke described its aging management review (AMR) of heat exchanger performance testing activities in Section 4.17 of Exhibit A of the LRA. The applicant credits these activities with managing aging effects for heat exchangers in several systems. Those systems include the low-pressure injection system, the component cooling system, the reactor building cooling system, and the standby shutdown facility's heating, ventilation and air conditioning system and auxiliary service water system. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging on heat exchanger functions will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.12.2 Summary of Technical Information in the Application

In Section 4.17 of Exhibit A of the LRA, the applicant describes heat exchanger performance activities that manage aging effects from fouling and loss of material. The performance activities verify continuing capability of these heat exchangers to perform their intended function under all current licensing basis (CLB) conditions for the period of extended operation. The affected systems and performance activities are described in more detail below.

The low pressure injection (LPI) system removes decay heat during cold shutdown and refueling operations. During unit cooldown, the reactor coolant temperature and pressure are reduced using the steam generators. At approximately 250°F and 300 psig, the applicant places the LPI system into service. The system draws reactor coolant through the decay heat drop line and through the decay heat removal coolers before returning the coolant to the reactor coolant system. The decay heat coolers must remain intact and provide adequate heat transfer. The decay heat coolers of the LPI system are exposed to borated water through the tubes, and raw water in the shell and on the outer surface of the tubes. The shell of the decay heat coolers is made from carbon steel, and all other components are made of stainless steel. The applicant identified fouling on the raw water side of the tubes as an applicable aging effect because fouling may reduce the heat transfer capability of the decay heat coolers.

The component cooling system provides cooling water to various components in the reactor building. The component coolers of this system transfer heat to the low pressure service water system. The coolers are exposed to raw water through the tubes and treated water on the outer surface of the tubes. The tubes and tubesheet are fabricated from admiralty brass while the channel head and shell are fabricated from carbon steel. The applicant identified fouling on the raw water side of the tubes as an applicable aging effect because fouling may reduce the heat transfer capability of the component coolers.

The reactor building cooling system cools the reactor building during both normal operating and accident conditions. The cooling units of this system transfer heat from the containment atmosphere to the low-pressure service water system. The cooling units are exposed to raw water through the tubes and ventilation air through the ducts and on the outer surface of the tubes. The duct work is made of aluminum, galvanized steel, and stainless steel. The tubes are made of 90-10 copper-nickel, the tube fins are made of copper, and the headers are made of stainless steel. The applicant identified fouling on the raw water side of the tubes as an applicable aging effect because fouling may reduce the heat transfer capability of the reactor building cooling units.

The standby shutdown facility (SSF) heating, ventilation, and air conditioning (HVAC) system maintains the SSF environment within a predetermined temperature range to support equipment operability. The HVAC system contains one heat exchanger that is within the scope of license renewal. The unit consists of air-cooling coils and a water-cooled condenser (considered to be part of the SSF auxiliary service water system). The air-cooling coils provide both a heat transfer and pressure boundary function. The cooling coils transfer heat from the supply air in the SSF HVAC system to the refrigerant while the condenser rejects the heat from the refrigerant to the SSF auxiliary service water system. The cooling coils are exposed internally to refrigerant while the external surfaces are exposed to the ventilation air environment. The tubes of the cooling coils are made from copper and have aluminum fins. The applicant identified potential loss of material in the aluminum components from galvanic corrosion because loss of the fins may reduce the cooling capacity of the heat exchanger. The applicant did not identify any aging effects associated with exposure of the cooling coils to refrigerant. The water-cooled condensers are exposed to raw water through the tubes, and refrigerant in the shell and on outer surface of the tubes. The tubes and tubesheet of the condensers are made of 90-10 copper-nickel; all other components of the heat exchangers are made of carbon steel. The applicant identified fouling and loss of material in the carbon steel and 90-10 copper-nickel components exposed to raw water as applicable aging effects because fouling and loss of material may reduce the cooling capacity of the heat exchanger. The applicant identified no aging effects associated with exposure to refrigerant.

3.2.12.3 Staff Evaluation

The staff evaluation of the heat exchanger performance testing activities focused on how the activities manage aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to aging management review. The staff evaluation of the applicant's quality assurance program is provided separately in Section 3.2.3 of this staff safety evaluation report. This program satisfies the elements of corrective actions, confirmation process, and administrative controls.

Program Scope
The applicant clearly defined the purpose and the scope of the heat exchanger performance testing activities. The staff did not identify additional heat exchangers that should have been included in the scope of this program. Thus, the staff finds the scope of the applicant's program 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
During the tests for the LPI decay coolers and the reactor building cooling units, the applicant measures flow rates and temperature differences across the heat exchangers. The staff finds these parameters acceptable because they are considered standard for this type of application and proven effective for detecting reduction of cooling capacity caused by fouling and/or loss of material. For the component coolers and the SSF HVAC coolers, the applicant measures flow rate of the raw water through the condensers. In Open Item 3.2.12-1, the staff requested the applicant provide additional information to justify why temperature difference across the SSF HVAC coolers is not measured. The staff did not agree that all aging effects, specifically loss of material, could be managed by measuring only flow rates for these coolers. In its October 15, 1999 response, Duke agreed that the heat exchanger performance testing activities do not adequately manage loss of material. The applicant provided the staff a description of a new preventive maintenance activity for the coolers that the staff finds adequate to manage loss of material. A detailed description and our evaluation of that new activity is described in Section 3.2.10 of this SER. Open Item 3.2.12-1 is closed.

Detection of Aging Effects
On page 4.17-1 of the LRA, the applicant states that the frequency of the performance testing of the reactor building cooling units is on a refueling outage basis. In the applicant's response to RAI 4.17-1, the applicant stated that the reactor building cooling units receive a heat transfer test quarterly (see Attachment 2, page 18 of the RAI response dated February 8, 1999). The staff requested that the applicant clarify this discrepancy. The applicant responded in a letter dated May 10, 1999, that both statements are correct. Oconee improved standard technical specification (ISTS) 3.6.5.4 requires the units be tested on a refueling frequency. Selected licensee commitment (SLC) 16.6.3 requires the units be tested as needed, based on projected fouling rates. Generally this "as needed" testing has occurred on a quarterly basis. The component coolers are tested each refueling outage. The SSF HVAC coolers are in service at all times because they are required for SSF system operability, per Improved Technical Specifications 3.10.1.D. The applicant monitors the flow rates through these heat exchangers

twice per day. The applicant has been performing this test since 1986 with satisfactory results. Thus, the staff finds the frequency of testing can be relied upon to detect aging effects before there is a loss of intended function.

Monitoring and Trending
The applicant monitors and trends test results to predict the proper time for corrective actions (i.e., inspection and cleaning). The staff finds this aspect acceptable in that the trending aspect provides for corrective actions before there is a loss of intended function.

Acceptance Criteria
In Open Item 3.2.12-2, the staff requested the applicant provide the acceptance criteria and the basis for the acceptance criteria for the heat exchanger performance testing activities. In its October 15, 1999 response, Duke provided this information for the SSF HVAC coolers, decay heat coolers, and reactor building cooler units in its response to Open Items 3.2.12-1 and 3.2.12-2. For the SSF HVAC coolers, the applicant measures flow rates through the SSF HVAC coolers. The applicant also implements a preventive maintenance activity (evaluated in Section 3.2.10 of this SER) that measures operating temperatures across the coolers. Based on flow rates and operating temperatures, Duke then can calculate the heat transfer coefficient of the coolers and determine that adequate cooling is provided for the SSF. For the decay heat coolers and reactor building cooler units, the applicant measures both flow rates and operating temperatures across these heat exchangers to calculate the heat transfer coefficient for each cooler. Duke then uses the heat transfer coefficient to determine the total containment heat removal capability under both normal and accident conditions. Because the decay heat coolers can only be tested during a refueling outage, Duke applies an additional conservatism of 4% to the heat transfer value acceptance criteria to ensure operation under all design basis scenarios. The value of 4% is based on testing and operating experience. The applicant does not apply this 4% additional conservatism to the reactor building cooling units because those units are tested more frequently, on a quarterly basis, which provides for more effective trending of results. The staff finds the acceptance criteria acceptable because they are appropriately tied to the component intended function of the coolers. Any aging effects such as fouling or loss of material will result in a decrease in the cooling capacity of the coolers and will be detected by the applicant through the activities described above. On this basis, Open Item 3.2.12-2 is closed.

If the heat exchangers fail to meet the acceptance criteria, the applicant takes corrective actions, such as cleaning, in accordance with the quality assurance program. If normal testing reveals degraded performance that leads to maintenance being performed on a heat exchanger, the applicant tests the heat exchanger after completing the maintenance to verify the restoration of acceptable conditions.

Operating Experience
In RAI 4.17-1, the staff requested that the applicant provide ONS-specific operating experience that demonstrates the effectiveness of heat exchanger performance testing activities. The

applicant responded by stating that the heat exchanger program has been in effect since 1986. The test results initiate cleaning of the heat exchangers before there is a loss of component intended function. Since early 1986, all the decay heat removal coolers have been cleaned at least once as a result of the heat transfer test. With respect to the reactor building cooling units, the applicant stated that new cooling units were installed on all three ONS units in the early 1990s. With respect to the SSF HVAC, the applicant stated that only one of the two coolers has required a cleaning since their installation in the early 1980s. The applicant stated that test frequencies are adjusted as indicated by current test results. The applicant provided the staff information that supports the attributes of its heat exchanger performance testing activities.

The staff noted that there was no specific reference to NRC Information Notice (IN) 97-41, "Potentially Undersized Emergency Diesel Generator Oil Coolers." In RAI 4.17-8, the staff requested that the applicant describe how IN 97-41 applies to the ONS heat exchangers. Because fouling of heat exchanger tubing has been identified as an applicable aging effect, appropriate actions to avoid problems similar to those discussed in the IN may be necessary for the ONS heat exchangers. In its response Duke stated that according to IN 97-41 EDG oil coolers designed and constructed prior to 1985 would be considered undersized when inputting the design data into the new industry design equation developed in 1985. The design equation for cooling *viscous* shell side fluids was modified after extensive testing of industrial-sized heat exchangers. The Information Notice noted that this does not necessarily mean that they are now inadequate for meeting the design requirements, but they do have a lower fouling margin that would require more frequent cleaning and testing. This Information Notice was reviewed within Duke for applicability to Oconee EDG oil coolers. The results of this review determined that the oil coolers were adequately sized and no corrective actions were needed. Section 4.17 of Exhibit A of the Application presents Heat Exchanger Performance Testing Activities for managing fouling of the reactor building cooling units, decay heat removal coolers, and the SSF HVAC heat exchangers in the SSF Auxiliary Service Water System. None of these heat exchangers are oil coolers. Therefore, the Information Notice was considered not relevant for these heat exchangers. The staff concurs with the applicant's determination as discussed above that IN 97-14 does not impact the Oconee heat exchangers. On this basis the staff concerns, relative to RAI 4.17-8, are considered resolved.

3.2.12.4 Conclusions

The staff has reviewed the information in Section 4.17, "Heat Exchangers Performance Testing Activities," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Heat Exchanger Performance Testing Activities' will adequately manage aging effects associated with heat exchangers in the low-pressure injection system, the component cooling system, the reactor building cooling system, the standby shutdown facility's heating, ventilation and air conditioning system, and auxiliary service water system, for the period of extended operation.

3.2.13 Service Water Piping Corrosion Program

3.2.13.1 Introduction

Duke described its aging management review (AMR) of the service water piping corrosion program in Section 4.25 of Exhibit A of the license renewal application (LRA). The applicant credits this program with managing aging effects, specifically loss of material from corrosion, for a variety of systems. The affected systems include those within the scope of license renewal that have components exposed to the service water environment. These systems include the auxiliary service water system, the condenser circulating water system, the essential siphon vacuum system, the siphon seal water system, the high pressure service water system, the low pressure injection system, the component cooling system, the low pressure service water system, the standby shutdown facility auxiliary service water system, the Keowee service water system, the Keowee turbine generator cooling water system, and the Keowee turbine sump pump system. The staff reviewed this section of the application to determine whether the applicant has demonstrated that the effects of aging on service water piping will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.2.13.2 Summary of Technical Information in the Application

Several ONS systems within the scope of license renewal have a raw water internal operating environment. The components within these systems are made from various materials, including brass, bronze, carbon steel, cast iron, copper, ductile cast iron, and stainless steel. The applicant identified loss of material from general corrosion, pitting, galvanic corrosion, microbiologically influenced corrosion (MIC), and selective leaching as applicable aging effects for these materials exposed to a raw water environment. The applicant relies on several aging management programs to manage these aging effects for these systems and components. These programs include the preventive maintenance activity assessment, galvanic susceptibility inspection, cast iron selective leaching inspection, fire protection program, and service water piping corrosion program. The staff evaluation of the service water piping corrosion program is discussed below.

In Section 4.25 of Exhibit A of the LRA, the applicant describes an inspection and analysis program developed to verify the integrity of various systems exposed internally to a raw water environment. The applicant relies on the service water piping corrosion program to manage aging effects, specifically loss of material from various forms of corrosion, that may occur in these systems. The program aims to ensure that the component intended functions are maintained under all current licensing basis (CLB) conditions for the period of extended operation.

3.2.13.3 Staff Evaluation

The staff evaluation of the service water piping corrosion program focused on how the program manages aging effects through the effective incorporation of the following 10 elements: program scope, preventive or mitigative actions, parameters monitored or inspected, detection of aging effects, monitoring and trending, acceptance criteria, corrective actions, confirmation process, administrative controls, and operating experience.

The application indicated that the corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance plan pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff evaluation of the applicant's Quality Assurance Plan is provided separately in Section 3.2.3 of this staff Safety Evaluation Report. This program satisfies the elements of "corrective actions," "confirmation process," and "administrative controls."

Program Scope
The scope of the program includes all bronze, carbon steel, cast iron, and stainless steel components exposed to raw water and included within the scope of license renewal. The applicant clarified that program focus to date is on the carbon steel piping components exposed to raw water because they are the most susceptible to general corrosion and can serve as a leading indicator of the general material condition of the system components. The applicant stated that the program does not currently include inspections of the Keowee systems because the components in that system remain bounded by the overall program results. The applicant has established more than 30 carbon steel piping component inspection locations throughout the various systems encompassed by this program. The applicant established these inspection locations based on the assumption that fluid flow rates are the prime contributor to the conditions conducive to corrosion. The applicant performs inspections spread among four flow regimes: stagnant, intermittent, low flow (approximately less than 3 feet per second or less), and normal flow (greater than 3 feet per second).

In Open Item 3.2.13-1, the staff requested that the applicant discuss how loss of material is managed for the other material types exposed to raw water (e.g., copper, brass and ductile iron). In its response dated October 15, 1999, Duke stated that the service water piping corrosion program is not focused on specific components within each specific system; rather, the program consists of inspections of locations with conditions that are characteristic and/or bounding of conditions found throughout the various raw water systems within the scope of license renewal. The applicant stated that corrosion of copper, brass and ductile iron are bounded or represented by inspections of brass and carbon steel piping. The staff agrees because brass is more susceptible than copper to corrosion in this environment and, therefore, the brass inspections are bounding. The staff also agrees that the corrosive effects on carbon steel in this environment are similar to those for ductile iron and, therefore, the carbon steel inspections are representative. Thus, the staff considers that the service water piping corrosion program adequately addresses corrosion of these materials due to exposure to raw water, and Open Item 3.2.13-1 is closed.

In Open Item 3.2.13-2, the staff requested that the applicant provide the technical basis for relying on inspections of carbon steel components for general corrosion to "serve as a leading indicator" of the condition of other components (e.g., stainless steel) susceptible to localized corrosive mechanisms such as pitting or MIC. In its response dated October 15, 1999, Duke emphasized that gross material loss due to general corrosion is of primary concern because it can lead to structural instability and directly impact component intended functions. Localized corrosion, such as pitting and crevice corrosion, would reveal itself through pinhole leaks in the piping components. Pinhole leaks, due to their small size and localized characteristics, should not impact the component intended function or pose a threat to structural integrity. The applicant plans to enhance the service water piping corrosion program to document Oconee operating experience associated with incidents of throughwall leaks due to localized corrosion. The applicant stated no such incidents have occurred to date. Duke will initiate any needed changes to the service water piping corrosion program through its corrective actions program. The staff agrees that operating experience to date supports the program as described by the applicant and finds the planned enhancement to the program adequate to address the issue of localized corrosion. On this basis, Open Item 3.2.13-2 is closed.

In Open Item 3.2.13-3, the staff requested the applicant to state specifically how the Keowee system is bounded. In its response dated October 15, 1999, Duke clarified that the service water piping corrosion program inspects representative materials from representative environments. The program currently inspects components in the Oconee and standby shutdown facility that are representative (with respect to materials and environments) of components in the Keowee raw water systems. The applicant applies the results from its inspections of the Oconee and standby shutdown facility to the components in the Keowee systems. The staff finds the practice of applying the results from one system to another acceptable because the materials and environments are similar and thus, the effects of corrosion can be expected to be similar. On this basis, Open Item 3.2.13-3 is closed.

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.

Parameters Inspected or Monitored
The applicant inspects the bounding locations using ultrasonic test techniques (UT), supplemented by visual inspections if access to the interior surfaces is allowed, such as during plant modifications. In Open Item 3.2.13-4, the staff requested the applicant to justify the use of UT for localized degradation. As described earlier in this section for Open Item 3.12.3-2, the applicant does not inspect for localized degradation as part of the service water piping corrosion program. General corrosion is the corrosion mechanism of concern at this time and UT is an adequate inspection tool. Duke agreed that the use of UT for localized corrosion is not very

effective. If localized corrosion becomes a concern for service water system components, the applicant will apply appropriate techniques to manage this aging effect as part of its corrective action program. On this basis, Open Item 3.2.13-4 is closed.

Detection of Aging Effects
The frequency of service water piping inspections varies for different locations and depends on the results of previous inspection, but inspections are usually performed once every 5 to 10 years. The applicant performed the first inspections in the early 1990s. The applicant determines the frequency of reinspection based on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events, and plant operating experience. Most locations have received one reinspection at the time of the license renewal application. The staff finds the basis on which the applicant determines the inspection frequency reasonable.

Monitoring and Trending
The applicant identifies wall loss from corrosion and performs trending for those locations based on subsequent inspection results. The applicant relies, in part, on calculated rates of material loss to project the next inspection interval or repair time. The staff finds this aspect of the program acceptable because trending of the inspection results will enhance the applicant's ability to detect aging effects before there is a loss of intended function.

Acceptance Criteria
The program defines the minimum pipe wall thickness for the inspection locations within the scope of the program. The applicant determined these values based on design pressure or structural loading using the piping design code of record. The applicant compares inspection results with the minimum pipe wall thickness values. If the applicant finds that an inspection location fails to meet the minimum acceptance criteria, the applicant repairs or replaces the affected component prior to returning the system to service, unless an engineering evaluation allows further operation. For cases in which the applicant allows a component to remain in service, the applicant establishes the reinspection interval as part of the program. The applicant implements corrective actions in accordance with its quality assurance program. The staff finds the applicant's acceptance criteria adequate to allow for appropriate corrective action before aging effects cause loss of function.

Operating Experience
The applicant began the program in the 1980s and formalized the service water piping corrosion program in 1993. The applicant took the first sets of piping wall thickness data in 1990 and found minimal, to no wall loss at all inspection locations. These initial results confirmed the slow-acting nature of general corrosion, as these components had then been in service approximately 20 years. Inspection results obtained since 1990 continue to confirm the sound condition of the applicant's raw water system piping, with respect to carbon steel and general corrosion. The applicant has not needed to replace any piping based on the results of the piping inspections performed under this program.

3.2.13.4 Conclusions

The staff has reviewed the information in Section 4.25, "Service Water Piping Corrosion," of Exhibit A of the LRA. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the service water piping corrosion program will adequately manage aging effects associated with a loss of material from corrosion for those systems within the scope of license renewal that also have components exposed to the service water environment for the period of extended operation.

3.3 Containment Structures

3.3.1 Introduction

Duke describes the aging effect considerations for the reactor buildings (containments) in Section 3.3 of Exhibit A of the LRA. Section 3.3 of the LRA also identifies the aging management programs (AMPs) that Duke credits for managing the identified aging effects for the components of the ONS containments. Section 4.7, "Coatings Program," Section 4.8, "Containment Inservice inspection Plan," and Section 4.9, "Containment Leak Rate Testing Program" of the LRA have been credited by Duke for managing the aging effects on the components of the ONS containment. The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the ONS containment 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

3.3.2.1 Structures and Components Subject to an Aging Management Review

As pointed out in Section 2.2.1.2 of this SER, the applicant divides the containment structure into containment components, i.e., concrete components, steel components, and post-tensioning tendons. Each component has a "component grouping". For example, concrete components are grouped as (1) dome and cylinder, (2) floor above the basemat, and (3) foundation slab (i.e., basemat). The applicant describes the aging effects and AMPs for containment structures at ONS in Sections 3.3 and 4.8 of the LRA. The applicant also states that the Oconee coatings program and containment leak rate testing (LRT) program are part of the containment AMP. These programs are described in Sections 4.7 and 4.9 of the LRA.

3.3.2.2 Effects of Aging

In Section 3.3 of Exhibit A of the LRA, the applicant describes the aging effects for each of the component groups. Each component group is evaluated with respect to (1) ambient environment, (2) loss of material, (3) cracking, (4) change in material properties, (5) industry experience, and (6) ONS operating experience. The discussion on these aspects of the evaluation assesses the potential aging effects on the component groups.

The applicant describes the process to determine the aging effects applicable to the containment structural components. The process begins with an understanding of the potential aging effects described in industry literature. From this set of potential aging effects, the component materials, operating environment, and operating stresses define which aging effects apply to each component that is subject to an AMR. These applicable aging effects are then validated by a review of industry and ONS operating experience to provide reasonable assurance that the full set of applicable aging effects has been identified for each component subject to an AMR. Table 3.3-1, reproduced from the LRA, shows the specific aging effects for which the applicant has identified AMPs.

3.3.2.3 Aging Management Programs

The applicant identifies the containment ISI plan as a program to manage the effects of aging on containment components during the period of extended operation. The plan describes the essential elements of the ISI requirements of Subsections IWE and IWL of Section XI of the ASME Code in Section 4.8 of the LRA. Containment functionality as a leak-tight barrier is verified by the containment LRT requirements of Appendix J of 10 CFR Part 50. The applicant describes the essential elements of the LRT program, which is considered as a part of the containment AMP in Section 4.9 of Exhibit A of the LRA. Of the three types of LRT to be performed, the applicant considers Type A (integrated) and Type B (local) LRT part of the containment AMP. Type C LRT, performed to measure isolation valve leakage rates, is not considered part of the containment AMP. The integrity of the coatings is important for inhibiting degradation of the steel component surfaces of the ONS containments. The applicant states that the Oconee coatings program is relevant for managing the aging effects on the steel components.

The following table, reproduced from Exhibit A of the LRA, Revision 2, summarizes the applicant's AMP with respect to the aging effects considered for the containment structures at ONS.

Table 3.3-1 Applicable Aging Effects for Reactor Building (Containment) Components

Component	Applicable Aging Effect(s)	Aging Management Programs
Concrete Components		
Cylinder Wall Dome Floor Foundation Slab	Cracking Change in material properties due to leaching	Containment ISI Plan •Examination Category L-A, Concrete

Component	Applicable Aging Effect(s)	Aging Management Programs
Steel Components		
Anchorage, Embedments, and Attachments Electrical Penetrations Emergency Personnel Hatch Equipment Hatch Fuel Transfer Tubes Liner Plate Mechanical Penetrations Personnel Hatch	Loss of material from corrosion • for the liner, hatches, and penetrations if the coatings are not maintained • for the liner below the concrete floor if the expansion joint sealants are not maintained • for the liner behind welded attachments if the cavity formed between the attachment and the liner is not sealed	1. Coatings Program 2. Containment ISI Plan (Subsection IWE of ASME Section XI) • Examination Category E-A, Containment Surfaces • Examination Category E-C, Containment Surfaces Requiring Augmented Examination • Examination Category E-D, Seals, Gaskets, and Moisture Barriers • Examination Category E-G, Pressure Retaining Bolting, • Examination Category E-P, All Pressure Retaining Components • Welds within the scope of Examination Categories E-B, Pressure Retaining Welds, and E-F, Pressure Retaining Dissimilar Metal Welds, will be examined within the scope of the Examination Category E-A, examination. 3. Containment Leak Rate Testing (Appendix J 10 CFR 50)
Post-Tensioning System		
Tendon Anchorage Tendon Wires	Loss of material at tendon anchorages	Containment ISI Plan • Examination Category L-B, Unbonded Post-Tensioning System

As shown in the table, the AMP for the containment components comprises three programs: (1) "Coatings Program," (2) "Containment Inservice Inspection Plan," and (3) "Containment Leak Rate Testing." These programs (described in Sections 4.7, 4.8, and 4.9 of Exhibit A of the LRA) are summarized in the following sections.

3.3.2.3.1 Coatings Program

The ONS coatings program has four service levels based on the anticipated operating conditions. For each of these service levels, the ONS coatings program contains guidance for:

- establishment of coating schedules

- selection and procurement of coatings
- specification of surface preparation and coating application requirements, including inspection requirements and criteria

Service Level I coatings apply to exposed surface areas within the containment, which are designed to withstand the postulated loss-of-coolant accident environment (LOCA). Service Level I coatings are specified in an ONS coating schedule and apply to structures and components within the containment, including (but not limited to) the liner plate, structural steel and support steel, hangers, concrete equipment bases, insulated piping and pipe hangers, electrical penetrations, polar crane, and carbon steel attachments to the liner plate. Service Level I coatings currently used for maintenance have been LOCA-tested in their installed configuration, i.e., over the original coating in accordance with ANSI N101.2 and ANSI N101.4. Duke specifications are based on industry standards (References 4.7-3, 4.7-4, 4.7-5, 4.7-6, 4.7-7, 4.7-8, 4.7-9, 4.7-10, 4.7-11, and 4.7-12 of the LRA). These standards are used in surface preparation, application of the coating, and quality control inspections during the coating process. Additional descriptions of the coatings inside the reactor building are given in the ONS UFSAR, Chapter 3, Table 3-12.

In conclusion, the applicant states that the ONS coatings program has been in effect at ONS since prior to initial licensing. The program is based on well-established industry standards and has been revised as necessary on the bases of ONS experience. The continued implementation of the ONS coatings program provides reasonable assurance that the specified coatings will remain intact under design loading conditions so that the base material is not subject to the detrimental effects of aging, including loss of material due to corrosion or wastage, and the coated structure or component will continue to perform its intended functions consistent with the current licensing basis (CLB) for the period of extended operation.

3.3.2.3.2 Containment Inservice Inspection Plan

The containment ISI plan is described in Section 4.8 of Exhibit A of the LRA. For each inservice inspection interval of the license renewal term, the plan will:

(1) Implement the examination requirements of either:

    (a) 10 CFR 50.55a (61 FR 41303, August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWE, “Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants,” and Subsection IWL, “Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants,” with the limitation listed in Subsection (b)(2)(vi) and the modifications in Subsections (b)(2)(ix) and (b)(2)(x) of 10 CFR 50.55a; or

(b) The edition of the ASME Section XI Code required by 10 CFR 50.55a(b) prior to start of the 120-month ISI interval or another edition of ASME Section XI provided an appropriate evaluation is performed in accordance with the regulatory requirements in effect at the time; or

(c) Another edition of ASME Section XI provided an appropriate evaluation is performed in accordance with the regulatory requirements in effect at the time; or

(2) Comply with 10 CFR 50.55a (g)(4)(ii), except that if an examination required by the Code or Addenda is determined to be impractical, a relief request will be submitted to the Commission in accordance with 10 CFR 50.55a(5)(iv), for Commission evaluation.

In the following paragraphs of the LRA, the applicant discusses the essential elements of Subsections IWE and IWL in terms of scope, aging effects or relevant conditions, frequency of examination, acceptance criteria, corrective actions, and quality controls. In Sections 4.8.1.2 and 4.8.2.2, the applicant described the operating experience and demonstration of the effectiveness of the plan as an AMP. These sections of the LRA are summarize below.

For the steel liners of the ONS concrete containments, Subsection IWE is expected to be effective in managing loss of material due to corrosion of the base metal during the period of extended operation because it contains examination requirements for containment steel component surface areas that are subject to degradation and aging. Furthermore, NUREG-1540 states that inspection mandated by Appendix J to 10 CFR Part 50, though basically visual, has been reasonably effective in identifying containment problems known to date.

Based on the above review, the applicant states that the implementation of the Subsection IWE examinations of the containment ISI plan, in conjunction with the coatings program (see Section 4.7) and the containment LRT program, provides reasonable assurance that the aging effects will be managed so that the containment steel components will continue to perform their intended functions consistent with the CLB for the period of extended operation.

The containment LRT program (see Section 4.7.1) complements the Subsection IWE examinations and provides additional assurance that the steel components of the containment, that form the essentially leak-tight barrier, will be maintained during the period of extended operation.

For the concrete components of the ONS containments, Subsection IWL is expected to be effective in managing corrosion of the post-tensioning system because it contains examination requirements similar to Regulatory Guide (RG) 1.35. Furthermore, information contained in NUREG/CR-6424 supports Duke's conclusion that current examination programs appear adequate to ensure the continuing physical integrity of post-tensioning systems.

In December 1997, during the ONS Unit 1 tendon surveillance required by ONS Custom Specification 4.4.2, some precursor conditions of abnormal tendon degradation were observed. These precursor conditions indicated higher than normal water content in tendon filler grease, presence of free water, grease leakage from the reactor building, lower than expected tendon elongation, and low filler grease reserve alkalinity. The engineering evaluation concluded that these precursor conditions did not result in loss of tendon prestress forces and that the examined tendons were capable of performing their intended functions. The tendon surveillance was conducted using the methodology contained in RG 1.35, Revision 3. Furthermore, Duke states that the staff has previously determined that the requirements contained in Subsection IWL for tendon surveillances are similar to those contained in this regulatory guide. Accordingly, inspections performed in accordance with either RG 1.35, Revision 3, or Subsection IWL will provide reasonable assurance that the functionality of the tendons will be maintained.

Based on the above review, the applicant concludes that the implementation of the Subsection IWL examinations of the containment ISI plan provides reasonable assurance that the aging effects will be managed so that the containment post-tensioning system will continue to perform its intended functions consistent with the CLB for the period of extended operation.

3.3.2.3.3 Containment Leak Rate Testing

The containment LRT program is described in Section 4.9 of Exhibit A of the LRA. The applicant states the purposes of the containment LRT are:

a. to assure that the leakage through the containment and systems and components penetrating containment shall not exceed allowable leakage rate values specified in the Improved technical specifications or associated bases, and

b. to assure that periodic surveillances of containment penetrations and isolation valves are performed.

The containment LRT program contains three types of tests: Type A, which are tests intended to measure the overall leakage rate of the containment; Type B, which are tests intended to measure leakage of containment penetrations whose design incorporates resilient seals and gaskets, including airlock door seals and equipment hatch gaskets; and Type C, which are tests to measure containment isolation valve leakage.

Of these three tests, only Type A and Type B are considered to be AMPs for license renewal. In Sections 4.9.1 and 4.9.2 of Exhibit A of the LRA, the applicant discusses Type A and Type B tests in terms of scope, aging effects, frequency, acceptance criteria, corrective actions and administrative controls. In Sections 4.9.1.2 and 4.9.2.2, the applicant described the operating experience related to Type A and Type B tests, which is summarized below.

More than 20 Type A integrated leak rate tests (ILRTs) have been performed for the ONS containments. Results have shown that all containment steel components have successfully passed the Type A ILRT. Based on the review of ONS operating experience, the continued implementation of the ONS Type A ILRT complements the Subsection IWE inservice examinations, providing reasonable assurance that the aging effects will be managed so that the containment will continue to perform its intended function consistent with the CLB for the period of extended operation.

Numerous Type B LLRTs have been performed at ONS in over 20 years of operation. Results of previous Type B tests have shown few failures. When test failures have occurred, they have been traced to failure of nonmetallic components (gaskets, o-rings). Results have shown no test failures of steel components during the Type B LLRT. Based on the above review, the continued implementation of the ONS Type A ILRT and Type B LLRT, which complement the ASME Section XI, Subsection IWE inservice examination, provides reasonable assurance that the aging effects will be managed so that the containment will continue to perform its intended functions consistent with the CLB for the period of extended operation.

3.3.2.4 Time-Limited Aging Analyses

Based on the criteria in 10 CFR 54.3(a), the applicant identified TLAAs related to (1) containment liner plate and penetration fatigue and (2) the containment post-tensioning system. These analyses are evaluated in Sections 4.2.1 and 4.2.2 of this SER.

3.3.3 Staff Evaluation

3.3.3.1 Effects of Aging

In assessing the aging effects on containment components, the applicant evaluated the potential for age-related degradation of the containment components. As the age-related degradation mechanisms are mainly affected by the long-term exposure to sustained environmental conditions, the applicant discusses such effects based on the existing knowledge about the aging effects of such environment on the containment components. The applicant cites a number of relevant NUREG reports, industry reports, NRC Information notices and bulletins. These formed the basis for the assessment of the effects of aging on containment components. The applicant discusses the ONS operating experience for each of the containment components. Based on the combined database, the applicant identifies component attributes which should be monitored during the license renewal period. An open item from the June 1999 version of this report related to the aging effects is discussed below.

In Section 3.3.4.2 of Exhibit A of the LRA, Duke emphasized that in spite of the water infiltration and high humidity in the ONS tendon galleries, the tendon components were well protected. Based on the information contained in the database on the condition of the tendon grease caps and the bearing plates in tendon galleries (see Plates 2, 7, and 11 in Appendix A of

NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"), the staff did not agree with the applicant's conclusion. The intended function of the post-tensioning system is to impose compressive forces on the concrete containment structure to resist the internal pressure resulting from a design-basis accident with no loss of structural integrity. Operational experience, as documented in NUREG-1522, has shown that water infiltration and high humidity in the tendon gallery can be a significant aging effect on the vertical tendon anchorages that could potentially result in loss of the ability of the post-tensioning system to perform its intended function. Therefore, this aging effect needs to be adequately considered. This was identified as Open Item 3.3.3.1-1.

In its October 15, 1999 response to this open item, Duke stated; "based on the discussion in Section 4.8 of Exhibit A of the Application, the implementation of the *Containment Inservice Inspection Plan* provides reasonable assurance that the aging effects of the tendon anchorages, including those in the gallery, will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation." The staff closes open item 3.3.3.1-1, with a note that managing the condition and environment in the tendon galleries, e.g., moisture and humidity, may be a prudent way to manage the degradation (i.e. corrosion) of bearing plates and other vertical tendon anchorage components in the tendon galleries.

The staff considers the aging effect considerations for ONS containments acceptable.

3.3.3.2 Aging Management Program for License Renewal

The containment AMP consists of three separate programs:

Exhibit A of the LRA Section 4.7, "Coatings Program"
Exhibit A of the LRA Section 4.8, "Containment Inservice inspection Plan"
Exhibit A of the LRA Section 4.9, " Containment Leak Rate Testing"

The staff evaluation of these AMPs focused on the program elements rather than details of specific plant procedures. To determine whether the Duke AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the programs in context of the following 10 elements: (1) scope of the program, (2) preventative actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

3.3.3.2.1 Coatings Program

The ONS coatings program is an existing program. The purpose of the ONS coatings program is to protect systems and components from the effects of the environment and to reduce personnel exposure to as low as reasonably achievable in areas subject to radiation and contamination.

Coatings inside containment must remain intact during a postulated design-basis event or be documented as unqualified with no impact on the reactor building emergency sump. Information for this review was obtained from the LRA and from Duke's response dated November 11, 1998, to GL 98-04, "Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment."

Scope of the Program
The scope of the ONS coatings program includes prequalification of Service Level I coatings; guidance for coating schedules and selection and procurement of coatings; and specification of surface preparation and coating application requirements, including inspection requirements and criteria. Also within the scope of the ONS coatings program, is the periodic assessment of existing coatings as stated in the applicant's 10 CFR Appendix B, criterion IX program. The program is applicable to all inscope structures and components. The staff finds the scope of the program for aging management of containment coatings adequate.

Preventive Actions
The application did not discuss any preventive actions, and the staff did not identify any need for preventive actions for coatings in the ONS containments.

Parameters Monitored or Inspected
The parameters to be monitored or inspected are given in ANSI 101.2, ANSI 101.4 and ASME Section XI, Subsection IWE. Parameters monitored for prequalification of Service Level I coatings include responses to irradiation and design-basis accidents. Parameters monitored during application of the coatings include surface preparation, dry film thickness, and visual inspection of the coating for damage. Parameters monitored during periodic assessment of coatings include the visual appearance of the coating and the presence of corrosion products. The periodic assessments of coatings are conducted during each refueling outage. The staff finds that this element is appropriately included in the program.

Detection of Aging Effects
The effects of aging are identified in ANSI 101.2 and ANSI 101.4. Effects of aging for coatings include rusted areas, blisters, crazing, and peeling. Such effects are monitored or inspected as part of the program. The staff finds that effects of aging are properly identified in ANSI standards 101.2 and 101.4 and their detection is part of the applicant's coating program.

Monitoring and Trending
This element is not discussed in the LRA, and the staff does not see a need for trending.

Acceptance Criteria
The acceptance criteria for coatings is no visible evidence of areas of rust, blisters, crazing, and peeling as stated in ANSI 101.2 and ANSI 101.4. The staff finds that the acceptance criteria are adequate.

Corrective Actions, Confirmation Process and Administrative Controls
The application states that the corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and includes all structures and components subject to an AMR. The staff's evaluation of these elements is provided separately in Section 3.2.3 of this SER.

Operating Experience
The application does not discuss operating experience for the coatings in the LRA. However, the applicant did give the results of the most recent periodic condition assessment of coatings at ONS in its response to Generic Letter 98-04. They are summarized below for the purpose of this SER.

The last assessment of the coatings in Unit 1 containment occurred in September 1997 during the 1EOC17 refueling outage. The general overall condition of the coatings was satisfactory. Degraded coatings were evaluated and prioritized for repair during the current outage or in a future outage, as necessary. The sprinkler grid system and the polar crane had degraded coatings which were documented and will continue to be evaluated for potential removal and replacement.

The last assessment of the coatings in Unit 2 containment occurred in March 1998, during the 2EOC16 refueling outage. The general overall condition of the coatings was satisfactory. Degraded coatings were evaluated and prioritized for repair during the current outage or in a future outage, as necessary. The sprinkler grid system, the polar crane, and dome area contained degraded coatings, which were documented and will continue to be evaluated for potential removal and replacement.

The last assessment of the coatings in Unit 3 containment occurred in October 1998 during the 3EOC17 refueling outage. The general overall condition of the coatings was satisfactory with any degraded coatings evaluated and prioritized for repair during the current outage or for future outages as necessary. The sprinkler grid system, the polar crane, and the dome had degraded coatings that were documented and will continue to be evaluated for potential removal and replacement.

The staff concludes that the applicant has demonstrated that the coatings program is an effective AMP for maintenance of coatings in ONS containments. On the basis of its review, as set forth above, the staff concludes that the applicant has demonstrated that the 'Coatings Program' will adequately manage aging effects associated with containment coatings for the period of extended operation.

3.3.3.2.2 Containment Inservice Inspection Plan

The containment ISI plan essentially implements Subsections IWE and IWL of Section XI of the ASME Code as currently incorporated by reference in 10 CFR 50.55a, supplemented by the containment coating program and the containment LRT program.

Scope of the Program
This program relates to the periodic inspections of containment structures as required by Subsections IWL and IWE of the ASME Section XI Code. These subsections identify the specific containment structures requiring inspection. The Code has been incorporated in 10 CFR 50.55a by reference. This program in combination with the containment coating program and the containment LRT program is sufficient in scope to manage the effects of aging on the Oconee containment structures.

Preventive Actions
An effective implementation of the containment coating program (see section 3.3.3.2.1 of this SER) assures that the essential leak-tight barriers of the ONS containments will be protected from the environmental effects.

Parameters Monitored or Inspected
The parameters monitored and/or inspected are integrity of the coating, loss of material from corrosion, cracking and other degradations in concrete, expansion joint sealant integrity at the junction of the cylindrical walls and the concrete, seal integrity of the liner behind the attachment welds, loss of material in the prestressing tendon system, (e.g., corrosion of tendon anchorages, wires, corrosion inhibiting material). The staff finds the parameters monitored and/or inspected acceptable for managing the effects of aging on ONS containment structures.

Detection of Aging Effects
The staff finds that with the implementation of Subsections IWE and IWL, supplemented by the additional requirements of 10 CFR 50.55a, significant aging effects will be detected, principally, by visual examination. When there is a thickness reduction in the leak-tight barrier (containment liner), the reduction in thickness will be measured by volumetric examination.

Monitoring and Trending
All the parameters described in the "monitoring and trending" section of the SRP will be monitored as part of this plan. Additionally, 10 CFR 50.55a(b)(2)(ix)(B) requires the trending of prestressing forces in ONS tendons. This is further discussed in Section 4.1.2 of this SER under the TLAA for prestressing tendons.

Acceptance Criteria
Acceptance criteria for ONS containment liner and penetrations are in accordance with IWE-3500. Acceptance criteria for the concrete components of the containments and prestressing system are in accordance with the requirements of IWL-3000. The staff considers

these acceptance criteria adequate for ensuring the integrity of the pressure retaining-boundaries of the ONS containment structures.

Corrective Actions, Confirmation Process, and Administrative Controls
The applicant has stated that the areas of degradation not found acceptable by engineering evaluation would be corrected by repair or replacement in accordance with the applicable sections of Subsections IWE and IWL of Section XI of the ASME Code. The staff finds the applicant's approach acceptable. Moreover, the applicant has stated that the specific corrective actions will be implemented in accordance with the "Duke Quality Assurance Program." Duke's quality assurance program, including corrective actions, confirmation process, and administrative controls, is evaluated in Section 3.2.3 of this SER.

Operating Experience
The relevant operating experiences regarding corrosion of liner plate and prestressing forces in the ONS post-tensioning system are discussed in Sections 3.3.2.6, 3.3.3.6, and 3.3.4.4 of Exhibit A of the LRA. These operating experiences have been considered in developing the containment AMPs at ONS. The applicant has also considered industry-wide experience. The applicant should consider the information in the recently published NRC IN 99-10, "Degradation of Prestressing Tendon Systems in Prestressed Concrete Containments," for appropriate incorporation in this program.

3.3.3.2.3 Containment Leak Rate Testing

Scope of the Program
Type A and Type B tests of Appendix J of 10 CFR 50 are credited for managing leak-tight integrity of the containment pressure boundary. The applicant states that Type C testing is not credited for aging management of isolation valves. In RAI 4.9-1, the staff requested the applicant to discuss how the leak-tight integrity of the outboard containment isolation valves is verified. In response, the applicant stated that, depending on the systems containing the outboard containment isolation valves, other programs are credited with managing the effects of aging, as applicable, of these valves. Recognizing the implementation of other inservice inspection and inservice testing requirements of the systems containing these valves, and the aging management programs for mechanical components described in Section 3.5 of the LRA, the staff considers the scope of the program adequate.

Preventive Actions
The applicant does not discuss the preventive actions for the leak-rate testing program, and the staff did not identify the need for any.

Parameters Monitored or Inspected
Leakage through containment penetrations, leakage through access openings, and leakage through the containment structure are the parameters monitored in this program.

Detection of Aging Effects
The implementation of this existing program has been (and will be) effective in detecting the degradations (age-related or not) in the containment pressure boundary components, including seals and gaskets. A significant feature of this program is the program's ability to detect unacceptable leakage through the containment pressure boundary. The staff considers the program will adequately detect aging on the containment structural components.

Monitoring and Trending
As stated above, in *Parameters Monitored or Inspected.* Time-dependent trending of leakage rates is not required. However, the applicant is required to keep track of inadequate performance, as discuss below in *Operating Experience.*

Acceptance Criteria
The acceptance criteria for leakage are prescribed in the applicant's TS, and they are acceptable for the extended period of operation of the plant units.

Corrective Actions, Confirmation Process, and Administrative Controls
The basis for corrective actions will be Appendix J of 10 CFR Part 50 for leakage-related corrective actions. The quality assurance for corrective actions, confirmation process, and administrative controls will be in accordance with the "Duke Quality Assurance Program." This program is evaluated in Section 3.2.3 of this SER.

Operating Experience
As discussed in Section 3.3.2.3.2 of this SER, the operating experience described by the applicant indicates that the program is effective in detecting unacceptable leakage through the containment pressure boundary.

3.3.3.3 Time-Limited Aging Analyses

The time-limited aging analyses (TLAAs) for (a) liner plate and penetration fatigue and (b) the containment post-tensioning system are evaluated in Sections 4.2.1 and 4.2.2 of this SER.

3.3.4 Conclusion

The staff has reviewed the information in Section 3.3, "Aging Effects for Reactor Building (Containment) Structural Components," Section 4.7, "Coatings Program," Section 4.8, "Containment Inservice inspection Plan," and Section 4.9, "Containment Leak Rate Testing Program," of Appendix A of the LRA. On the basis of its review, the staff concludes that the applicant has demonstrated that the aging effects associated with the containment structural components at ONS will be adequately managed so that there is reasonable assurance that the containment structures at the ONS units will perform their intended functions in accordance with the CLB during the period of extended operation.

3.4 Reactor Coolant System

3.4.1 Introduction

Duke described its aging management review (AMR) of the reactor coolant system (RCS) in the following 19 sections of Exhibit A of its license renewal application (LRA). The NRC staff reviewed these sections to determine whether the applicant has demonstrated that the effects of aging on the reactor coolant system (RCS) will be adequately managed so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3):

3.4.1	Description of process to identify the applicable aging effects for RCS components and Class 1 component supports
3.4.3	Reactor Coolant System Piping
3.4.4	Pressurizer
3.4.5	Reactor Vessel
3.4.6	Reactor Vessel Internals
3.4.7	Once Through Steam Generators
3.4.8	Reactor Coolant Pumps
3.4.9	Control Rod Drive Tube Motor Housings
3.4.10	Letdown Coolers
4.3.1	AMP for Alloy 600
4.3.7	AMP for Pressurizer Examinations
4.3.11	AMP for Reactor Vessel Internals
4.3.12	AMP for Small-Bore Pipe Inspection
4.6	Chemistry Control Program
4.10	AMP for Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations
4.22	AMP to Inspect High-Pressure Injection Connections to the RCS
4.23	RCS leakage monitoring
4.24	AMP for Reactor Vessel Integrity
4.26	AMP for Steam Generator Tube Surveillance

The applicant previously described its aging management programs (AMPs) for the reactor coolant system in a series of Babcock and Wilcox Owners Group (B&WOG) topical reports. These reports are:

BAW-2243	Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping
BAW-2244	Demonstration of the Management of Aging Effects for the Pressurizer
BAW-2248	Demonstration of the Management of Aging Effects for the Reactor Vessel Internals
BAW-2251	Demonstration of the Management of Aging Effects for the Reactor Vessel

Aging Management Review

The staff previously approved BAW-2243 and BAW-2244, having determined that they presented adequate information to meet the requirements stated in 10 CFR 54.21(a)(3) for managing the effects of aging on the RCS for license renewal. Section 1.3.1 of this SER contains the status of BAW-2248 and BAW-2251, which were reviewed concurrently with Duke's LRA. Open items and applicant action items from these topical reports are discussed in this section of the SER.

An applicant may incorporate NRC-approved reports by reference if the conditions of approval in the safety evaluation (SE) of the specific report are met. Duke used the following process to meet the conditions stated in the SEs for incorporating approved B&WOG topical reports by reference:

- Comparison of the component intended functions of the RCS components under review. The Oconee Nuclear Station (ONS) specific component screening review first identifies the component intended functions and then compares these functions to those identified in the generic B&WOG topical reports. Differences are noted and justified.

- Identification of the items that are subject to an AMR. ONS drawings and pertinent design and field change data are reviewed.

- Identification of applicable aging effects. An independent assessment of the applicable aging effects was performed by reviewing plant operating environment, operating stresses and ONS–specific operating experience. This assessment was done to validate aging effects identified in the generic B&WOG topical reports.

In Section 3.4.1 of Exhibit A of the LRA, Duke described how it identified the applicable aging effects for RCS components. Duke stated that Section 2.4 of Exhibit A of the LRA describes the RCS mechanical components that require an AMR. Section 3.4.1 also listed the B&WOG topical reports that are applicable to the ONS RCS and that Duke plans to incorporate by reference. Section 3.4.1 of Exhibit A of the LRA is purely introductory and is not evaluated by the staff.

3.4.2 Summary of Technical Information in The Application

3.4.2.1 Structures and Components Subject to an Aging Management Review

The RCS mechanical components that require an AMR are B&W-designed vessels (i.e., the reactor vessel and control rod drive mechanism pressure boundary, pressurizer, and OTSGs) and reactor vessel internals, specifically the plenum assembly, the core support barrel assembly, and the lower internals assembly, with the addition of the thermal shield and the thermal shield restraint, the reactor coolant pumps, and all Class 1 piping, valves, and bolting. Brief descriptions of the components that comprise the RCS follow. For the most part, functions, environments, and materials, are described in the referenced topical reports.

Reactor Coolant System Piping

RCS piping includes piping (including fittings, branch connections, safe ends, and thermal sleeves); valve bodies (pressure-retaining parts of RCS isolation/boundary valves); and bolted closures and connections.

Duke states that the ONS units are bounded by NRC approved BAW-2243A with regard to the scope of the RCS piping and materials of construction. It also states that the operating environments (i.e., water chemistry and qualitative stresses) of the ONS RCS piping are consistent with the environments described in BAW-2243A.

Pressurizer

The pressurizer is a vertical cylindrical vessel with a bottom surge line penetration connected to the hot-leg piping by the surge line piping. The pressurizer contains electric heaters in its lower section and a water spray nozzle in its upper section. Since all sources of heat in the RCS are interconnected by piping with no intervening isolation valves, relief protection is provided on the pressurizer. Overpressure protection consists of two code safety valves and one power-operated relief valve. Piping attached to the pressurizer is Class 1 up to and including the first isolation valve and is discussed in Section 2.4.3 of Exhibit A of the LRA. Pressurizer supports are addressed in Section 2.4.11.2 of Exhibit A of the LRA.

Duke determined that the following items are subject to an AMR for the pressurizer:

- Pressurizer vessel
- Nozzles
- Other pressure-retaining items
- Bolted closures
- Integral attachments
- Internal spray piping and spray head

Duke stated that the ONS units are bounded by BAW-2244A with regard to the scope of pressurizer items in the first five groups defined above. The internal spray piping and the pressurizer spray head were not in the scope of BAW-2244A, but they are in the scope of license renewal and subject to an AMR for ONS.

Duke stated that the operating environments, i.e., water chemistry and qualitative stresses, of the ONS pressurizer are consistent with these described in BAW-2244A.

Reactor Vessel

The reactor vessel consists of the cylindrical vessel shell, lower vessel head, closure head, nozzles, interior attachments, and all associated pressure-retaining bolting. Coolant enters the reactor through the inlet nozzles, passes down through the annulus between the thermal shield and vessel inside wall, reverses at the lower head, passes up through the core, turns around through the plenum assembly, and leaves the reactor vessel through the outlet nozzles.

Duke states that it reviewed the current design and operation of the ONS reactor vessels using the process described in Section 2.4.1 of Exhibit A of the LRA, and has confirmed that they are bounded by the description contained in BAW-2251. Duke further states that it has committed to programs described in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor components. Duke has verified that all stated commitments will be subject to appropriate regulatory control and that it has identified and evaluated any deviations from the above-mentioned AMPs on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

Reactor Vessel Internals

The reactor vessel internals consist of two structural subassemblies that are normally located within the reactor vessel. These two subassemblies of the internals are the plenum assembly and the core support assembly.

Duke, having reviewed the current design and operation of the ONS reactor vessel internals, has determined that they are bounded by the description contained in BAW-2248 except for the thermal shield and thermal shield upper restraint. These austenitic stainless steel items support an internals intended function and are subject to an AMR.

The components described below were not the subject of B&WOG topical reports.

Once-Through Steam Generators (OTSGs)

Each ONS unit has two OTSGs. Each is a vertical, straight tube, once-through, counterflow, shell-and-tube heat exchanger with shell-side boiling. The SG consists of upper and lower hemispherical heads welded to tubesheets that are separated by a seven-course shell assembly. Over 15,000 straight Alloy 600 tubes are held in alignment by 15 tube support plates.

OTSG items that are subject to an AMR are: the hemispherical heads, secondary shell, tubes, plugs, mechanical sleeves, tubesheets, primary nozzles, main and auxiliary feedwater nozzles, steam outlet nozzles, instrumentation nozzles, drain nozzles, all associated pressure-retaining bolting, and integral attachments. Class 1 RCS piping attached to the primary once-through steam generators' nozzles, including the welded joints, is addressed in Section 2.4.3 of Exhibit A of the LRA. Secondary piping attached to the OTSGs' nozzles, including the main and auxiliary feedwater headers and riser piping, is addressed in Section 2.5.9, "Steam and Power Conversion Systems" of Exhibit A of the LRA. The SG supports are addressed in Section 2.4.11.5 of Exhibit A of the LRA.

The hemispherical heads, tubesheets, and pressure retaining bolting are low-alloy steel. The primary inlet and exit nozzles, secondary shell, secondary outlet nozzles, primary and secondary manway covers, secondary hand hole covers, secondary vent and level sensing nozzles, and main and auxiliary feedwater nozzles are carbon steel. The primary drain nozzle, nozzle dam support rings, tubes, plugs, sleeves, and secondary temperature sensing connections are Alloy 600.

Reactor Coolant Pumps

Reactor coolant pumps (RCPs) provide the head required to transport the reactor coolant through the reactor core, piping, and SGs.

RCP items subject to an AMR are the casing, cover, and associated pressure-retaining bolting. Non-Class 1 piping, flexhose, instrumentation, and similar components attached to the reactor coolant pump are addressed in Section 2.5 of Exhibit A of the LRA. Class 1 piping connected to the pump, including the welded joints, are addressed in Section 2.4.3 of Exhibit A of the LRA. The pump casings are cast austenitic stainless steel joined by electroslag welding. The pump casings received two heat treatment cycles: solution annealing followed by a stabilizing treatment. Bolting is fabricated from low-alloy steel and martenistic stainless steel. Duke stated that the materials and operating environment of the RCS pumps, including the bolted closures and connections, are similar to those evaluated in the RCS piping reviews.

Control Rod Drive Mechanism Motor Tube Housings

Control rod drive mechanism motor tube housings (CRDMMTHs) provide the reactor coolant pressure boundary around the control rod drive mechanisms (CRDMs). During normal operation, the housings are filled with borated reactor coolant at the system operating pressure. Thermal barriers keep the temperatures in the housings below system temperature. The material of construction for the housings is stainless steel or Alloy 82/182-clad low-alloy steel (motor tube center section only for Type A and B drives).

Letdown Coolers

The letdown coolers are in the reactor building. The tubes, tubesheets, and channel heads in the coolers are stainless steel; the cooler shell is carbon steel. During normal operation, the letdown coolers cool the letdown flow from the RCS to prevent damage to the purification system ion exchange resins. Internally, water from the RCS passes through the tubes and is cooled by the component cooling system (by treated water) on the shell side. The ONS chemistry control program has specifications for periodically monitoring the quality of the RCS and component cooling system water. According to the chemistry control program, Duke maintains corrosion inhibitors in the component cooling system and monitors certain impurities.

3.4.2.2 Effects of Aging

Duke determined that the aging effects for the components subject to an AMR are the following:

- cracking from stress-corrosion cracking, irradiation-assisted stress corrosion cracking (IASCC), fatigue, and thermal fatigue
- loss of material from intergranular attack, pitting, wear, erosion-corrosion, erosion, and wastage
- loss of fracture toughness from thermal aging and neutron embrittlement
- loss of mechanical closure integrity (bolting preload)
- mechanical distortion (of steam generator tubes)

Survey of Industry Experience

To validate its determination of applicable aging effects for all the components discussed above, Duke surveyed the industry experience and its own operating history. The survey included NRC generic communications, licensee event reports from nuclear power plants other than ONS, and NRC NUREGs. The documents reviewed in the survey are listed in Section 3.4.10.3 of Exhibit A of the LRA. The survey identified no additional aging effects beyond those identified in this section, nor did Duke observe any additional aging effects beyond those discussed in this section.

Duke identified two recent leaks associated with the ONS RCS piping. One leak was from a crack in the weld connecting the piping to the nozzle safe end on one of the two normal high-pressure injection lines. The cause was thermal fatigue. The other leak was from a crack in a 1-inch nominal pipe size (NPS) weld in a drain line off the pressurizer surge line. The cause was SCC coupled with vibration. The crack had initiated from the external surface. Investigation of the leak showed no evidence of cracking initiated from the inside diameter.

The review of Oconee operating experience of the letdown coolers identified that the letdown cooler heat exchanger tubes did experience cracking in the past as a result of improper operation of the coolers. The cooler design parameters were established for both coolers in a parallel configuration to be in operation during normal letdown and during cooldown after a reactor trip. For a number of years, only one cooler was in operation with the other in standby. During this time, a reactor trip increased flow through the operating cooler, causing severe thermal and vibrational stresses on the tubes, which eventually cracked. Two of the six letdown coolers have been replaced; the other four have been repaired and operating procedures have been changed to eliminate this practice.

3.4.2.3 Aging Management Programs

Duke identified the following AMPs for the RCS:

- Boric acid wastage surveillance program
- Chemistry control program
- Inservice inspection plan
- Program to inspect HPI connections to the RCS
- RCS operational leakage monitoring
- Alloy 600
- Small bore piping inspection
- Pressurizer examinations
- CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program
- Reactor Vessel Integrity Program
  - reactor vessel materials fracture toughness surveillance
  - reactor vessel materials Charpy upper shelf energy (USE)
  - reactor vessel pressurized thermal shock (PTS)
- Steam generator tube (SGT) surveillance program
- CASS flaw evaluation procedure
- Reactor vessel internals
- Pump and valve inservice test (IST) programs for vent valve bodies in core support shield assemblies of ONS Units 1,2, and 3

Duke concluded these programs would manage aging effects in such a way that the intended function of the components of the RCS would be maintained consistent with the current licensing basis (CLB), under all design loading conditions during the period of extended operation.

3.4.2.4 Time-Limited Aging Analyses (TLAAs)

Section 3.4.3, "Reactor Coolant System Piping," of Exhibit A of the LRA references topical report BAW-2243A. Likewise, Section 3.4.4, "Pressurizer," of the LRA references BAW-2244A, and Section 3.4.5, "Reactor Vessel," of the LRA references BAW-2251. Applicable aging effects for the CRDMMTH fall within the scope of the RCS piping. The staff SEs of these reports state that these reports do not address specific TLAAs of the RCS, the pressurizer, or the reactor vessel. It is left up to the individual plant to address TLAAs. By letter dated December 2, 1998, the staff requested that Duke demonstrate for ONS Units 1, 2, and 3, that the ASME Code Section III cumulative usage factor for all RCS Class 1 piping and pressurizer Class 1 components will be less than or equal to 1.0 for 60 years of plant operation. By letter dated February 17, 1999, Duke stated that applicable fatigue TLAAs for the RCS piping, the pressurizer, and the reactor vessel were addressed in Section 5.4.1.1 of Exhibit A of the LRA. Additional information was also presented in responses to staff RAIs 5.4.1-2 through 5.4.1-5.

Fatigue, USE, and PTS are evaluated as TLAAs in Section 4.0 of this SER.

3.4.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.4.3, 3.4.4, 3.4.8, 4.3.1, 4.3.7, 4.3.12, 4.5, 4.22, and 4.23 of Exhibit A of the Duke LRA and the staff's previous SEs on the topical reports BAW-2243, BAW-2244 (included in BAW-2243A and BAW-2244A), BAW-2251, and BAW-2248, regarding the applicant's demonstration that effects of aging will be adequately managed so that the intended function would be maintained consistent with the CLB for the period of extended operation for the RCS.

There were a number of action items in the staff's previous SEs on BAW-2243 and BAW-2244. The action items, Duke's responses, and the staff's evaluations are given below.

Action Items From Previous Staff Evaluation of BAW-2243A

As discussed below, the staff finds that Duke's responses to Items 1-7 resolve the action items of BAW-2243A.

Item 1: When incorporating BAW-2243 in its renewal application, the renewal applicant is to verify that its plant is bounded by the topical report.

Response: Duke participated in developing BAW-2243A by providing ONS-specific design and operational information. Duke has reviewed the current design and operation of the ONS RCS piping and confirms that this piping is bounded by the description contained in BAW-2243A.

Item 2: The applicant is to commit to programs identified as necessary in the report to manage the effects of aging on the functionality of the RCS piping components.

Response: Program descriptions contained in the ONS UFSAR are considered by Duke to be commitments.

Item 3: A summary description of these programs is to be presented in the license renewal UFSAR supplement in accordance with 10 CFR 54.21(d).

Response: Descriptions of these programs are provided in Exhibit B (UFSAR Supplement) of the Application for Renewal of Operating Licenses, Oconee Nuclear Station Units 1, 2, and 3.

Item 4: Any deviations from the AMPs described in this report as necessary to manage the effects of aging during the period of extended operation, to maintain the functionality of the RCS piping components or other information presented in BAW-2243, such as materials of construction and edition of the ASME Code Section XI (including mandatory appendices), must be identified by the applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3).

Response: No deviations from the AMPs described in BAW-2243A or other information presented in the report has been identified by Duke.

Item 5: The B&WOG defers to the renewal applicant referencing this topical report for the development of the details of (1) the inspection of the Alloy 82/182-clad hot-leg segment and plant selection for that inspection, and (2) the sample inspection of small bore RCS piping.

The applicant must provide details of these two augmented inspection programs in its renewal application for staff review and approval.

Response: Descriptions of these programs are provided in the application. (See the staff's review of these programs below).

Item 6: Since B&WOG elected to exclude TLAAs applicable to the RCS piping components from the scope of the topical report and indicated that they will be resolved on a plant-specific basis, any renewal applicant referencing this report will have to evaluate TLAAs applicable to the RCS piping components in its renewal application in accordance with the requirements of 10 CFR 54.21(c).

Response: Evaluations of ONS specific TLAAs are provided in the application. (See the staff's evaluation of the TLAAs in Section 4.0 of this SER).

Item 7: Since the staff has made no finding relative to whether BAW-2243 constitutes the complete list of RCS piping components subject to an AMR or the adequacy of the scoping methodology, the individual applicants must identify and list the structures and components subject to an AMR and describe a methodology for developing this list as part of their LRA.

Response: The list of structures and components of the RCS that are subject to an AMR is provided in Section 2.4 of the application. The identification of individual components is also contained in ONS-specific documents maintained on site. The methodology for developing and maintaining this list of components is consistent with the guidance contained in NEI 95-10, Rev. 0. (See the staff's evaluation of Section 2.4 of Exhibit A of the LRA in Section 2.1 of this SER).

Action Items From Previous Staff Evaluation of BAW-2244A

As discussed below, the staff finds that Duke's responses to items 1-4 below resolve the action items of BAW-2244A. Item 5 is evaluated in this section and item 6 is evaluated in Section 4.0 of this SER.

Item 1: When incorporating BAW-2244 in its renewal application, the renewal applicant is to verify that its plant is bounded by the topical report.

Response: Duke participated in developing BAW-2244A by providing ONS-specific design and operational information. Duke has reviewed the current design and operation of the ONS pressurizers and confirms that they are bounded by the description in BAW-2244A, except for the internal spray line and spray head. These components were omitted from the generic report; however, they are credited with mitigation of a steam generator tube rupture in the ONS UFSAR and are subject to an AMR. Duke addressed the AMR in Section 3.4 and Chapter 4 of its application.

Item 2: The renewal applicant is to commit to programs identified as necessary in the Topical report to manage the effects of aging on the functionality of the pressurizer.

Response: Program descriptions in the ONS UFSAR are considered by Duke to be commitments.

Item 3: A summary description of these programs is to be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).

Response: Descriptions of these programs are presented in Exhibit B of the LRA.

Item 4: Any deviations from the AMPs described in this Topical report as necessary to manage the effects of aging during the period of extended operation to maintain the functionality of the pressurizer or other information presented in the report, such as materials of construction and edition of the ASME Code Section XI (including mandatory appendices), must be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3).

Response: No deviations from the AMPs described in BAW-2244A or other information presented in the report has been identified by Duke. Duke has identified the ONS internal spray line and spray head as within the scope of license renewal and subject to AMR.

Item 5: Since B&WOG defers the development of details of the additional sample volumetric inspection program of small-bore nozzles and safe ends to the renewal applicant referencing this topical report, the renewal applicant must provide details of the additional sample inspection program in its renewal application for staff review and approval.

Response: Duke described these programs in Chapter 4 of Exhibit A of its application. (The staff's evaluation is presented below under its evaluation of small-bore piping).

Item 6: Since B&WOG elected to exclude TLAAs applicable to the pressurizer from the scope of the topical report and stated that they will be resolved on a plant-specific basis, any renewal applicant referencing this report must evaluate TLAAs applicable to the pressurizer in its renewal application in accordance with the requirements of 10 CFR 54.21(c).

Response: Duke described these programs in Chapter 5 of Exhibit A of its application. (The staff's evaluation is presented in Section 4.0 of this SER).

There were also two open items (cracking of stainless steel cladding inside the pressurizer vessel and aging management of pressurizer heater penetration welds) listed in the staff's SE of BAW-2244 which the applicant addressed in Chapter 4 of Exhibit A of the LRA. The staff's evaluation is contained in Section 3.4.3.3 of this SER.

Action Items from Previous Staff Evaluation of BAW-2248

As discussed below, the staff finds that Duke's responses to the Renewal Applicant Action Items from this report resolve the action items.

Item 1: The license renewal applicant is to verify that the critical parameters for the plant are bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. The applicant for license renewal will be responsible for describing any such commitments and proposing the appropriate regulatory controls. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel internal components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

Response: Duke participated in the development of BAW-2248 by providing Oconee-specific design and operational information. Duke has reviewed the current design and operation of the Oconee reactor vessel internals and has determined that the internals are bounded by the descriptions contained in BAW-2248 with the exception of the thermal shield and thermal shield upper restraint, which is within scope for Oconee.

Staff evaluation of the aging management program for the thermal shield and the thermal shield upper restraint is provided in Section 3.4.3.3 of this SER.

Item 2: A summary description of the programs and evaluation of TLAAs is to be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).

Response: The application contains new and revised FSAR sections to provide a summary description of the programs and evaluation of TLAAs, in accordance with 10 CFR 54.21(d).

Item 3: The license renewal applicant must identify whether an intended function of the RVI is to provide shielding for the RPV. If not an intended function, the license renewal applicant should provide justification for that conclusion. Should a license renewal applicant determine that the RVI's intended function is to provide shielding for the RPV, then the items that support this intended function, such as, the thermal shield and the thermal shield upper restraint assemblies, must be identified and reviewed in accordance with 10 CFR 54.21(a)(3).

Response: The application states that the Oconee reactor vessel internals provide gamma and neutron shielding of the reactor vessels. Consideration of aging effects for the components supporting this intended function, specifically the thermal shield and the thermal shield upper restraint, and aging management are described in the application. Staff evaluation of the aging management program for the components supporting this intended function is provided in Section 3.4.3.3 of this SER.

Item 4: The applicant must commit to participation in the B&WOG RVIAMP, and any other industry programs as appropriate, to continue the investigation of potential aging effects for RVI components, and to establish monitoring and inspection programs for RVI components. The applicant shall provide the NRC with either annual reports or periodic updates (after completion of significant milestones) on the status of the RVIAMP, commencing within one year of the issuance of the renewed license.

Response: Duke has stated that they will participate in the B&WOG RVIAMP and other industry programs, as appropriate, to continue the investigation of potential aging effects for RVI components and to establish monitoring and inspection programs for RVI components. Duke will provide to the NRC periodic updates (after the completion of significant milestones) on the status of the Oconee Reactor Vessel Internals Inspection program commencing within one year after the issuance of the renewed license, and Duke will provide a final report to the NRC upon completion of the program.

Item 5: The applicant must describe plans for augmented inspection of RVI components for management of SCC/IASCC and loss of fracture toughness (neutron embrittlement) of the RVI components. This description should specify the sample size, the examination method, acceptance criteria and timing of the inspection, or the process to be used to specify these items.

Response: Duke provided descriptions of programs for inspecting baffle bolts, CASS RVI components, and non-CASS RVI components. These programs are described in a revised UFSAR and are evaluated by the staff in Section 3.4.3.3 of this SER.

Item 6: According to the B&WOG, one of its objectives in BAW-2248 states, "it is intended that NRC review and approval of this report will allow that no further review of the matters described herein will be needed when the report is incorporated by reference in a plant specific renewal license application." The license renewal applicant must address the baffle-former bolt cracking issues addressed in Section 3.3.2 of this SE pertaining to Refs. 4 and 5, with regard to the industry ITG project, initiated after April 23, 1998, to address generic RVI materials issues. The B&WOG indicates this industry effort resulted in subsequent changes in the B&WOG RVI aging management program. The ITG is currently addressing the issues of cracking of baffle bolts. The B&WOG indicates that the changes in the aging management program now requires the applicants to be responsible for using the industry ITG project developed information to determine the necessary steps (e.g., inspection, operability determinations, and replacements) for the management of the applicable baffle bolt aging effects.

Response: Duke has provided a description of a program for inspection of baffle-former bolts. This program is described in a revised UFSAR and is evaluated by the staff in Section 3.4.3.3 of this SER.

Item 7: The applicant must describe plans for augmented inspection of RVI components for management of loss of fracture toughness due to thermal aging embrittlement of the RVI components. This description should specify the sample size, the examination method, acceptance criteria and timing of the inspection, or the process to be used to specify these items.

Response: Duke provided a description of a program for augmented inspection of CASS RVI components, to manage loss of fracture toughness by thermal aging embrittlement and irradiation embrittlement. This program is described in a revised UFSAR and is evaluated by the staff in Section 3.4.3.3 of this SER.

Item 8: The applicant must describe plans for management of stress relaxation for bolted closures of the RVI. This description should specify the critical locations, monitoring and inspection techniques, and timing of the inspection, or the process to be used to specify these items.

Response: Duke provided a description of a program for augmented inspection of non-CASS RVI components, in part to manage stress relaxation of bolted closures. This program is described in a revised UFSAR and is evaluated by the staff in Section 3.4.3.3 of this SER.

Item 9: The applicant must address aging management of void swelling. An adequate aging management program (AMP) would include participation in industry program(s) to address the significance of void swelling (either individually or through an owners or industry group), a commitment to develop a sufficient inspection program (including the basis, methods, locations to be examined, timing, frequency and acceptance criteria) for management of the issue based upon the results of the industry programs, and a commitment to implement the inspection program prior to the end of the current license period.

Response: Void swelling is addressed as one part of the Oconee Reactor Vessel Internals Inspection. This program is described in a revised UFSAR and is evaluated by the staff in Section 3.4.3.3 of this SER.

Item 10: If flaws have been detected in the reactor vessel internals, a TLAA plant-specific evaluation must be performed to determine the flaw growth acceptance in accordance with the ASME B&PV Code, Section XI, inservice inspection requirements.

Response: The applicant has stated that no flaws have been found in the reactor vessel internals, therefore, no flaw growth evaluations need to be performed for ONS.

Item 11: The applicant must address the plant-specific plans to continue monitoring and tracking design transient occurrences.

Response: The Oconee Thermal Fatigue Management Program provides monitoring and tracking of design transient occurrences. Staff review of this program is provided in Section 4.2.3 of this SER.

Item 12: Plant-specific analysis is required to demonstrate that, under loss-of-coolant-accident (LOCA) and seismic loading, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and that irradiation accumulated at the expiration of the renewal license will not adversely affect deformation limits. The RVIAMP must develop data to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license.

Response: The applicant will develop the necessary data, and perform the necessary analyses, to demonstrate that the reactor vessel internals will have sufficient ductility to absorb local strain in the regions of high stress intensity and will meet the deformation limits at the end of the period of extended operation. The development of data and analysis will be performed as part of Duke's aging management program, which is discussed in Section 3.4.3.3 of this SER.

Action Items from Previous Staff Evaluation of BAW-2251

As discussed below, the staff finds that Duke's responses to the Renewal Applicant Action Items from this report resolve the action items.

Item 1: The license renewal applicant is to verify that its plant is bounded by the topical report. Further, the renewal applicant is to commit to programs described as necessary in the topical report to manage the effects of aging during the period of extended operation on the functionality of the reactor vessel components. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within this topical report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).

Response: Duke participated in the development of BAW-2251 by providing Oconee-specific design and operational information. Duke has reviewed the current design and operation of the Oconee reactor pressure vessels and has determined that the RPVs are bounded by the descriptions contained in BAW-2251.

Item 2: A summary description of the programs and evaluation of TLAAs is to be provided in the license renewal FSAR supplement in accordance with 10 CFR 54.21(d).

Response: The application contains new and revised FSAR sections to provide a summary description of the programs and evaluation of TLAAs, in accordance with 10 CFR 54.21(d).

Item 3: Since the staff has not made any finding on whether the B&WOG topical report provides the complete list of reactor vessel components subject to an aging management review or whether the scoping methodology is adequate, individual plant applicants will need to provide a comprehensive list of structures and components subject to an aging management review and the methodology for developing this list as part of their license renewal applications. Any components determined by the applicant to be subject to an aging management review for license renewal, but not within the scope of the topical report, are required to be addressed in the license renewal application.

Response: The application provided a description of the reactor vessel and a list of the items subject to an aging management review. No additional components outside the scope of the topical report were identified by the applicant.

Item 4: The B&WOG has determined that the lower CRDM service support structure, including the weld that connects the lower CRDM service support skirt to the reactor vessel closure head, and the reactor vessel support skirt, including the weld that connects the reactor vessel support skirt to the transition forging, are subject to an aging management review for license renewal. However, the B&WOG has decided to exclude them from the scope of the topical report. Thus, a renewal applicant needs to address them in its license renewal application.

Response: The reactor vessel support skirt (including the attachment weld to the transition forging) and control rod drive service structure, including the attachment weld to the reactor vessel head, are described in the application, along with the applicable aging effects and aging management programs that manage the applicable aging effects. Staff evaluation of the aging management program for these components is provided in Section 3.4.3.3 of this SER.

Item 5: The license renewal application for Oconee needs to address the fatigue evaluation of the reactor vessel studs on a plant-specific basis.

Response: Fatigue of the reactor vessel studs is managed by the Oconee Thermal Fatigue Management Program. This issue is addressed in Section 4.2.3 of this SER.

Item 6: A license renewal applicant needs to discuss the plant-specific methodology and instrumentation used to assess the number of operational transients in its renewal application for staff review. The staff review will also include the number of operating cycles applicable to the reactor vessel studs.

Response: The Oconee Thermal Fatigue Management Program monitors operational transients. Staff review of this program is provided in Section 4.2.3 of this SER.

Item 7: The B&WOG identifies flaw growth acceptance in accordance with the ASME Section XI ISI program as a TLAA, but indicates that flaw growth acceptance evaluation is plant-specific, is not within the scope of the report, and will be resolved on a plant-specific basis. Thus, a license renewal applicant needs to address it in the renewal application.

Response: Flaw growth acceptance under ASME Section XI is addressed in the application and evaluated by the staff in Section 4.2.3.3 of this SER.

Item 8: Alloy 600 components in the reactor vessel such as CRDM housings and other penetrations may be subject to crack initiation and growth. The B&WOG originally proposed to use the ASME Section XI program, supplemented by leak detection and surveillance of boric acid, to manage cracking of Alloy 600 components. In an April 1, 1997, response to the staff's request for additional information concerning Generic Letter 97-01, "Stress Corrosion Cracking of Control Rod Drive Mechanisms and Other Vessel Head Penetrations," the B&WOG stated: "Each participating plant will address additional requirements for RV head penetrations, including closure head penetrations less than 2 inch N.S. (i.e., thermocouple nozzles at TMI-1 and ONS-2)." Thus, a license renewal applicant referencing the topical report will need to submit its plant-specific program to manage cracking of Alloy 600 components in the reactor vessel in its renewal application for staff review.

Response: The applicant indicates that aging management of these items will be accomplished through the (new) "Alloy 600 Aging Management Program" and the (existing) "CRDM and Other Vessel Head Penetration Inspection Program." These programs are described and evaluated in Section 3.4.3.3 of this SER.

Item 9: During the review of the topical report, the staff had a question regarding the need to update the reactor vessel fracture toughness estimates with new data as it becomes available. In its August 11, 1997, RAI response, the B&WOG states: "Each license renewal applicant will define a process to ensure that the time-dependent parameters used in the TLAA evaluations reported in BAW-2251 are tracked such that the TLAA remains valid through the period of extended operation. The process will be defined on a plant-specific basis at the time of the licensee renewal application." Thus, a license renewal applicant needs to describe such a process in its application for staff review. If new information affects the conclusions of the topical report for the applicant's plant, the applicant needs to update its TLAA evaluations as appropriate and provide the updated evaluations in its renewal application for staff review.

Response: The *Reactor Vessel Integrity Program* and the *Oconee Thermal Fatigue Management Program* provide assurance that the TLAA contained in the Oconee UFSAR remain valid for the period of extended operation. These programs are reviewed and evaluated by the staff in Sections 4.2.3 and 4.2.4 of this SER.

Item 10: In its August 11, 1997, RAI response, the B&WOG indicated that Oconee Unit 2 and TMI Unit 1 will provide updated predictions of RT_{PTS} for welds WF-25 and SA-1526, respectively, when the plant-specific application for license renewal is submitted. For plants with an RT_{PTS} value for 48 EFPY exceeding the corresponding PTS screening criterion, a license renewal applicant must address the requirements in 10 CFR 50.61(b)(3) by developing, and requesting staff approval for reasonably practicable flux reduction programs to avoid exceeding the PTS criterion.

Response: The applicant provided updated projections of RT_{PTS} for all three Oconee units. Staff evaluation of these projections is contained in Section 4.2.4.3.3 of this SER.

Item 11: If an applicant has installed flow stabilizers using Alloy 600 and/or Alloy 82/182 weld material, the applicant must include the flow stabilizers in its Alloy 600 aging management program. Alloy 600 and Alloy 82/182 weld materials are susceptible to cracking in primary water environments.

Response: The Oconee flow stabilizers are made of stainless steel and are attached to the stainless steel cladding with stainless steel weld material.

Item 12: Embrittlement of the reactor vessel will be managed to ensure intended functions of the reactor vessel for 60 years. For the staff to determine if the plant could be operated for 60 years, an applicant must show that an operating window will be available between the pressure-temperature limits and the net positive suction curves for the RC pumps for 60 years. Otherwise, the applicant will propose aging management activities to minimize the extent of embrittlement, or other alternatives, to permit safe plant operation for 60 years. Should the applicant show that the reactor could only be operated for a time period less than 60 years, the duration of the renewed license, if granted, would be limited to that time period.

Response: The applicant stated that the projected operating window at 48 EFPY for each unit is sufficient to conduct heatup and cooldown operations. The applicant's response to this item is described in Section 4.2.4.3.1 of this SER.

Item 13: The neutron fluence must be experimentally monitored by ex-vessel or in-vessel dosimetry, and if modifications to the design and operation of the plant changes either the neutron energy spectrum, gamma heating or the reactor inlet temperature, as discussed in section 3.3.4.1 of this safety evaluation, the licensee must notify the NRC and propose a program to determine the impact of the modifications.

Response: The applicant described the dosimetry program and actions to be taken should relevant modifications to the design or operation of the plants occur. These activities and the staff evaluation are provided in Section 3.4.3.3 of this SER.

During staff review of the Duke application, a question was raised concerning the need for aging management of the reactor vessel monitoring pipes, from the standpoints of both the Duke application and the topical report BAW-2251. These monitoring pipes serve a leak detection function in the event of reactor coolant leakage past the inner O-ring. In response (by letter dated November 19, 1999), the B&WOG stated that the monitoring pipes would be removed from the scope of BAW-2251A and addressed on a plant-specific basis by the applicant. This response resulted in the identification of Renewal Applicant Action Item 14 for BAW-2251. Concurrently, the staff directed SER Open Item 3.4.3.3-9 to Duke, with several specific questions concerning the monitoring pipes. The applicant responded to this open item in a letter dated December 17, 1999, and provided additional information concerning the geometry of the monitoring pipes. This additional description of the geometry enabled the staff to close both SER Open Item 3.4.3.3-9 and the renewal applicant action item from BAW-2251, as described below.

Item 14: Since the reactor vessel monitoring pipes are not addressed within the scope of BAW-2251, the applicant must identify and address aging of the reactor vessel monitoring pipes in accordance with 10 CFR 54.21(a)(3).

Response: By letter dated December 17, 1999, the applicant described the geometry of the reactor vessel monitoring pipes. In particular, the applicant identified that flow to the monitoring pipes is provided by a ½ in. diameter hole in the reactor vessel flange, which serves as an orifice to minimize leakage from the vessel flange area. This orifice would limit leakage to less than normal RCS makeup capacity and minimize the consequences of failure of the reactor vessel monitoring pipes. This closes Open Item 3.4.3.3-9.

3.4.3.1 Structures and Components Subject to an Aging Management Review

The staff evaluation of Duke's identification of structures and components subject to an AMR is presented separately in Section 2.2.3 of this SER.

3.4.3.2 Effects of Aging

RCS

The staff's SE of BAW-2243 concluded that B&WOG properly identified the potential aging effects to be evaluated for the RCS piping components.

Duke, in its LRA, included a section on piping in the HPI line that was the subject of staff review. ONS has experienced leaking of the HPI piping in the RCS. On April 21, 1997, a leak occurred in an unisolable section of a combined makeup and HPI line at ONS Unit 2. The cause of the leak was a crack in the weld connecting the piping to the nozzle safe end. Examination found additional cracks in the vicinity of the warming line and in the thermal sleeve and a gap in the contact area between the thermal sleeve and the safe end. The cause of the cracking in the weld, connecting the piping to the nozzle, and in the vicinity of the warming line was thermal fatigue. The cause of the cracking in the thermal sleeve was judged to be high-cycle fatigue due to flow-induced vibration. The examination and cause of the cracking is discussed in Information Notice (IN) 97-46, "Unisolable Crack in High-Pressure Injection Piping." This phenomenon was identified as the probable cause for similar safe-end cracking at Crystal River Unit 3 and other B&W plants (including ONS) in the early 1980s. This issue was previously addressed in IN 82-09, "Cracking in Piping of Makeup Coolant Lines at B&W Plants," and Generic Letter (GL) 85-20 "Resolution of Generic Issue 69: High Pressure Injection/Makeup Nozzle Cracking in Babcock and Wilcox Plants."

Based on previous examinations of the HPI lines, Duke has correctly identified the aging effect as cracking from thermal fatigue.

Pressurizer

The staff's SE of BAW-2244 concluded that B&WOG properly identified the potential aging effects to be evaluated for the pressurizer (for the items within the scope of BAW-2244).

Aging Management Review

The LRA stated that the aging effect for the spray head is cracking due to reduction in fracture toughness. The staff did not agree, since reduction in fracture toughness does not cause cracking. Reduction in fracture toughness causes cracked components to fail at lower stresses than they otherwise would fail, but reduction in fracture toughness is not the cause of the cracking. The staff believes that the aging effects for the spray head are cracking and reduction in fracture toughness due to thermal aging of the cast stainless steel. The staff requested that Duke properly identify the potential aging effects for the heater bundle penetration welds, cladding, spray line and spray head. This was Open Item 3.4.3.2-1.

In response to Open Item 3.4.3.2-1, Duke clarified that the applicable aging effects for the pressurizer spray head are cracking by fatigue and reduction of fracture toughness by thermal embrittlement. This clarification closes Open Item 3.4.3.2-1.

Reactor Vessel

The aging effects applicable to the ONS reactor vessel in the LRA are consistent with those described in BAW-2251 since ONS is bounded by the generic report with respect to materials of construction, operating environment, Level A and B service conditions, and operating experience.

Vessel Head Penetration Nozzles

On the basis of industry experience, the staff concurs with Duke that PWSCC is the aging effect that is applicable to vessel head penetration (VHP) nozzles. In 1989, the NRC staff identified PWSCC as an emerging technical issue to the Commission, after cracking was noted in Alloy 600 pressurizer heater sleeve penetrations at a domestic PWR facility. In September 1991, PWSCC-type flaw indications were detected in an Alloy 600 VHP in the reactor head at Bugey 3, a French PWR. Additional examinations were performed of the VHP nozzles of a number of European and Japanese PWRs, and some additional axially oriented flaw indications were detected in the VHP nozzles of several other European plants. In 1994, the American Electric Power Company recorded relevant PWSCC-type flaw indications in one of the VHP nozzles at D.C. Cook Unit 2 after completing augmented eddy current examinations of the nozzles during a routine refueling outage for the unit.

RV Internals

The aging effects identified by Duke as applicable to ONS reactor vessel internals are (1) cracking (initiation and growth); (2) reduction of fracture toughness; (3) loss of material (thinning); and (4) loss of mechanical closure integrity (bolted joints). The staff agrees that Duke has identified the aging effects that are applicable to ONS reactor vessel internals, on the basis of the description of the environment, the materials of construction, the ONS operating experience, and Duke's review of industry performance experience. However, the staff finds that change of dimensions due to void swelling must be reconsidered as an aging effect requiring an AMR, as described below.

<u>Change in Dimensions</u>

Section 3.1 of topical report BAW-2248 dismisses change in dimensions of the RVI components due to void swelling as a significant aging effect because there is no evidence of void swelling under PWR conditions. However, EPRI TR-107521 "Generic License Renewal Technical Issues Summary," cites several sources with different estimates of void swelling. One source predicts swelling as great as 14 percent for PWR baffle-former assemblies over a 40-year plant lifetime, whereas another source states that swelling would be less than 3 percent for the most highly irradiated sections of the internals at 60 years. The issue of concern to the staff is the effect of change of dimensions due to void swelling on the ability of the RVI to perform their intended function. The staff requested Duke provide the basis for concluding that void swelling is not an issue for RVI or provide an AMP. This was Open Item 3.4.3.2-2.

In response to Open Item 3.4.3.2-2, Duke incorporated void swelling as one item to be addressed by the Oconee Reactor Vessel Internals Inspection. This program is evaluated by the staff in Section 3.4.3.3 of this SER. This addition closes Open Item 3.4.3.2-2.

<u>Steam Generators</u>

As discussed in Section 3.4.7 of Exhibit A of the LRA, aging effects that may be applicable to the items that support the primary pressure boundary are loss of material, cracking, mechanical distortion of tubes, and loss of mechanical closure integrity. In addition to these aging effects, the staff considers fatigue to be an applicable aging effect for the steam generator tubes. The forces imposed on the tubes by the secondary fluid can cause high-frequency vibration of the tubes and eventual failure of the tubes from fatigue. The applicant did not identify fatigue of the OTSG tubes as an applicable aging effect, and the staff disagrees with this assessment. Fatigue due to flow-induced vibration and/or fluid elastic instability can result in circumferential cracking of the OTSG tubes. Past operational experience bears this out; in fact, fatigue failure of tubes at ONS led to two forced outages in 1994. Although fatigue is not considered an applicable aging effect by the applicant, as discussed in Section 3.4.3.3 of this SER, the staff finds that the applicant's aging management programs currently in place and credited for managing the affects of aging on the steam generator tubes are adequate to manage fatigue.

In a request for additional information (RAI), dated December 3, 1998, the staff requested the applicant to discuss why outside-diameter stress-corrosion cracking (ODSCC) was not considered an applicable aging effect for the steam generator tubes at ONS. The applicant responded in a letter dated February 17, 1999, that ODSCC had not been identified as an active degradation mechanism in once-through steam generator designs. However, the applicant recognized that ODSCC was a potential aging mechanism. The applicant stated that the aging management programs discussed in the license renewal application to manage pitting, IGA, PWSCC, IGA/SCC, and other active degradation mechanisms experienced by once-through steam generator tubes would provide adequate management of ODSCC if it were to occur. The staff agrees with the applicant's assessment.

Duke did not include fatigue or ODSCC as applicable aging effects. The staff considers fatigue and ODSCC applicable aging effects. However, the staff does not consider this an open item because the Duke program is capable of detecting these aging effects through the steam generator eddy current test program and the on-line primary to secondary leakage monitoring program.

In summary, with the inclusion of fatigue and ODSCC as applicable aging effects for the steam generators, the staff concludes that, on the basis of the applicant's description of the steam generator internal and external environments and materials, all applicable aging effects have been identified for the SGs, consistent with published literature and industry experience.

Reactor Coolant Pumps (RCPs)

Duke stated that the applicable aging effects are: (a) cracking at weld joints and reduction in fracture toughness of the CASS casings; (b) reduction in fracture toughness of the CASS covers; and (c) cracking of the bolting material, loss of bolting preload, and loss of ferritic material (low alloy steel) for the pressure-retaining bolting.

The aging effects for the pressure-retaining bolting is the same as the Reactor Coolant Systems piping bolted closures and connections evaluated in Section 3.4.3 of Exhibit A of the LRA.

Based on the description of the RCP internal and external environment, materials used to fabricate the pump casings, covers, and pressure-retaining bolting, the ONS operating experience, and Duke's survey of industry experience, the staff concludes that Duke has identified aging effects that are applicable for the reactor coolant pumps.

Control Rod Drive Mechanism Motor Tube Housing (CRDMMTH)

In Section 3.4.9.2 of Exhibit A of the ONS LRA, Duke identified that the CRDMMTH may be subject to cracking at the weld joints in the housings or to loss of mechanical closure integrity at the CRDMMTH flange. The staff concludes that Duke has appropriately identified the potential aging effects for the CRDMMTH for the following reasons:

- The CRDMMTHs are fabricated with a bimetallic weld between the CRDMMTH and the safe end of the control rod drive mechanism penetration nozzle. Such welds may be subject to high residual stresses, which may contribute to initiation of stress-corrosion cracking. To date, no age-related cracking, from either stress-corrosion cracking or fatigue-induced cracking, has been detected in any of the CRDMMTHs of domestic PWRs.

- The CRDMMTHs are secured at the other end to the remaining sections of the control rod drive systems by a bolted flange. Industry experience indicates that these gaskets may wear down over time and leak.

Letdown Coolers

As discussed in Section 3.4.2.2 of this SER, the review of the ONS operating experience of the letdown coolers identified that the letdown cooler heat exchanger tubes have experienced cracking and loss of material. However, as reported in Section 3.4.10.2 of Exhibit A of the LRA, no applicable aging effects were identified for the external surfaces of the letdown coolers exposed to the reactor building environment.

Based on the description of the internal and external environments and materials of the letdown coolers, the staff concludes Duke has identified aging effects that are consistent with published literature and industry experience.

3.4.3.3 Aging Management Programs for License Renewal

The staff evaluation of the Duke AMPs focused on the program elements rather than details of specific plant procedures. To determine whether the Duke AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The LRA states that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of Duke's corrective action program is presented separately in Section 3.2.3 of the SER. Therefore, these three elements will not be discussed further in this section.

Aging Management Programs for the RCS

The staff evaluation of Duke's AMPs listed below was previously approved in the staff's SE of BAW-2243 and will not be evaluated further in this section:

- Boric acid wastage surveillance program also, covered in Section 3.2.1 of this SER
- Inservice inspection plan also, covered in Section 3.2.5 of this SER
- RCS operational leakage monitoring also, covered in Section 3.2.7 of this SER

The following new AMPs are evaluated in this section:

- Alloy 600
- Small bore piping inspection
- Program to inspect HPI connections to the RCS
- CASS flaw evaluation procedure

Alloy 600 AMP

Introduction
Section 2.4 of Exhibit A of the LRA identifies Alloy 600 and Alloy 82/182 components of the RCS subject to an AMR. Section 3.4 of Exhibit A of the LRA identifies PWSCC as an applicable aging effect for such components. Section 4.3.1 of Exhibit A of the LRA describes the Alloy 600 AMP. This program, in combination with Duke's chemistry control program, inservice inspection plan, steam generator tube surveillance program, RCS operational leakage monitoring, pressurizer examinations, and CRDM nozzle and other vessel closure penetrations inspection program, manages PWSCC of Alloy 600 and Alloy 82/182 components.

Program Scope
The scope of the program includes all Alloy 600 base metal and all Alloy 82/182 weld metal in the RCS, except steam generator tubes, sleeves and plugs, which are managed by the steam generator tube surveillance program. The staff finds the scope of the Alloy 600 Program acceptable because it includes all Alloy 600 and Alloy 82/182 components, except steam generators which are addressed separately.

To determine the initial inspection locations, Duke completed a susceptibility study of all the Alloy 600 and Alloy 82/182 components in the RCS. Specifically, Duke considered the following parameters: maximum operating inside-surface stress, operating temperature, microstructure, surface condition, and water chemistry. Duke benchmarked the model using the two PWSCC events at B&W plants (the pressurizer nozzle cracking at ANO Unit 1 and the CRDM nozzle cracking at ONS Unit 2). Duke's susceptibility model appears to consider a comprehensive set of factors that contribute to PWSCC (e.g., operating stress, operating temperature, microstructure), and is consistent with staff expectations. The five most susceptible locations are the CRDM nozzles at ONS Unit 2, the pressurizer heater sleeves at ONS Unit 1, the pressurizer level taps and safe ends at ONS Unit 3, the pressurizer spray nozzle safe ends at ONS Unit 3, and the pressurizer vent nozzle at ONS Unit 3. The staff finds the applicant's inspection scope adequate in that the most susceptible locations will be inspected. The inspection results should be bounding for the remaining Alloy 600 and Alloy 82/182 components.

Preventive or Mitigative Actions
There are no preventive or mitigative actions associated with this program beyond standard repair and replacement plans should PWSCC occur, and the staff did not identify a need for such preventive or mitigative actions.

Parameters Inspected or Monitored
The specific inspection plans for the CRDM nozzles are described in Section 4.10 of Exhibit A of the LRA and evaluated by the staff in Section 3.4.3.3 of this SER. The specific inspection plans for the pressurizer heater sleeves are described in Section 4.3.7.2 of Exhibit A of the LRA and evaluated by the staff in Section 3.4.3.3 of this SER. The inspection plan for the pressurizer spray nozzle safe ends consists of a volumetric examination of the nozzle safe-end weld performed each inspection interval at each ONS unit as a part of Duke's inservice inspection plan. Duke describes its inservice inspection plan in Section 4.18 of Exhibit A of the LRA and the staff evaluation of this program is in Section 3.2.6 of this SER. Duke plans to develop new inspection programs for the remaining high-susceptibility components: the pressurizer level taps and safe ends, and the pressurizer vent nozzle. Duke intends to use a combination of surface and volumetric examinations. Duke will complete these inspections by February 6, 2013 (the end of the initial license term for ONS Unit 1). Duke plans to conduct inspections employing qualified inspection techniques and personnel, following the guidance in ASME Code Section XI. The staff finds Duke's use of surface and volumetric nondestructive examination techniques acceptable because these techniques have a demonstrated ability to detect the presence of PWSCC.

Detection of Aging Effects
Duke manages PWSCC of Alloy 600 and Alloy 82/182 components by doing engineering evaluations to predict the most susceptible components, coupled with periodic volumetric nondestructive examinations to confirm the predictions. This approach is supported by industry operating experience to date. Duke has already inspected some of its most vulnerable items and plans to inspect additional items before the end of its current licensing term. The schedule for some of these components is not specified other than that the inspections will be completed no later than February 6, 2013. The staff did not identify a need for a specific commitment from the applicant to perform the inspection at a particular time. Thus, recognizing that there are both advantages and disadvantages to performing inspections earlier rather than later in the time period following approval of the LRA, the staff accepts the applicant's general commitment to complete the inspection before the current operating license expires. The frequency of subsequent inspections will be based on findings of the initial inspections and will depend primarily on crack growth rates. Both the sample size and number of locations will be reevaluated following the completion of each inspection. These reevaluations will be documented annually once the inspections begin. As discussed earlier, the staff also found the susceptibility model, inspection scope, and inspection technique to be acceptable. This finding, combined with an acceptable inspection schedule, form the basis for the staff conclusion that Duke will detect PWSCC of Alloy 600 and Alloy 82/182 components before there is a loss of intended function.

Monitoring and Trending
Duke committed in Exhibit A of the LRA to performing periodic inspections of the most susceptible components to detect the occurrence of PWSCC. The staff finds this approach sufficient. This program involves no trending, and the staff did not identify the need for it.

Acceptance Criteria
The staff finds Duke's acceptance criteria acceptable because Duke stated any evidence of PWSCC will be evaluated and dispositioned in accordance with its Quality Assurance Program. All flaws will be evaluated, and corrective actions will be developed and implemented on a case-by-case basis, depending on the nature of the inspection findings. A complete replacement or repair in accordance with ASME Section XI may be appropriate for some locations. Taking no immediate action and monitoring by further inspections may also be appropriate. For example, the indications detected by Duke on several Alloy 600 CRDM nozzles at ONS Unit 2 were allowed to remain in service without immediate repair because the calculated growth rate plus the measured depth of the indications satisfied the staff's flaw depth criteria which was stated in the staff's safety evaluation dated November 19, 1993. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Operating Experience
The Alloy 600 program is a new program, but Duke presented operating experience that supports the attributes of the program (e.g., the susceptibility model, inspection scope, and techniques). In addition, industry-wide operating experience to date with PWSCC of Alloy 600 components supports the attributes of Duke's program. Although multiple crack like indications were detected in October 1994 on several Alloy 600 CRDM nozzles at ONS Unit 2, these indications were shallow and were attributed to craze cracking during fabrication of the nozzles. Duke used a variety of nondestructive examination techniques to identify and to confirm the indications. Duke reinspected two of the nozzles in 1996 and confirmed no growth of the crack like indications. The staff found that nozzles with these indications were acceptable for continued service both in 1994 and 1996 (see Letter from L.A. Wiens (USNRC) to J.W. Hampton (Oconee Nuclear Station), "Safety Evaluation of Control Rod Drive Mechanism (CRDM) Penetration Inspection Results–Oconee Unit 2 (TAC No. M90773)," dated March 31, 1995, and Letter from D.E. Labarge (USNRC) to J.W. Hampton (Oconee Nuclear Station), "Structural Integrity of Control Rod Drive Mechanism (CRDM) Penetration Nozzles No. 23 and 63–Oconee Nuclear Station Unit 2 (TAC No. M95291)," dated December 11, 1996). Duke plans a third inspection of its CRDM nozzles during the fall 1999 refueling outage. Duke completed two volumetric examinations of the pressurizer surge-nozzle-to-safe-end weld and spray-nozzle-to-safe end weld in accordance with ASME Section XI Code requirements, with no defects observed. The ONS units have not experienced any other instances of cracking of Alloy 600 or Alloy 82/182 by PWSCC, other than cracking of the steam generator tubes, plugs, or sleeves. In general, the Alloy 600 items and Alloy 82/182 welds in the B&W operating plants are believed to have a relatively low susceptibility to PWSCC, owing to the stress relief heat treatment that RCS components received during fabrication. Only one instance of through-wall cracking on an Alloy 600 item has been observed at a B&W operating plant (at a pressurizer level tap at Arkansas Nuclear One, Unit 1).

Conclusions Regarding Alloy 600 Program
The staff concludes Duke presented enough information in its LRA to demonstrate that the Alloy 600 Program is an effective AMP. The CRDM nozzles at the ONS units have been identified as

being the most susceptible Alloy 600 components in the ONS RCS. Duke has been an active participant in the joint NEI and B&WOG integrated program for CRDM nozzles, and has voluntarily performed volumetric and surface examinations of the CRDM nozzles at ONS Unit 2. In 1999, the staff informed NEI that the generic integrated program for inspecting vessel head penetration nozzles in the industry is acceptable to the staff (see Letter from J.R. Strosnider (USNRC) to D.J. Modeen (NEI), "Review of Generic Response to the NRC Requests for Additional Information Regarding Generic Letter 97-01," dated March 21, 1999). Because the applicant's responses to Generic Letter 97-01, "Degradation of Control Rod Drive Mechanism Nozzle and Other Closure Head Penetration Nozzles," indicate that Duke is an active participant in NEI's integrated program for CRDM nozzles, and because the Alloy 600 program calls for Duke to inspect the next four most susceptible components in the ONS RCS, the staff finds that Duke's Alloy 600 AMP is acceptable.

Small-Bore Piping Inspection

As described in the LRA, the small-bore piping inspection verifies that service-induced weld cracking is not occurring in the small-bore RCS piping. The small-bore piping inspection covers the ONS Class A piping welds in lines less than 4 inches nominal pipe size (NPS), including pipe, fittings, and branch connections.

The reason for this AMP is that small-bore piping may not be fully managed by the current ASME Code, Section XI program because the code does not require volumetric inspection of small-bore piping. Further, in many instances, small-bore piping cannot be isolated from the RCS and a leak could lead to a small-break loss-of-coolant accident (SBLOCA) and plant shutdown.

The small-bore piping inspection program will identify a sample of inspection locations in the piping to receive a destructive exam or a nondestructive examination that permits inspection of the inside surface of the piping. The sample will include pipe, fittings, and branch connections over the entire small-bore size range. To determine the inspection locations from the total population of welds, risk-informed approaches will be used to identify locations most susceptible to cracking. The consequences of weld failure, without respect to susceptibility, also will be evaluated to identify the most safety-significant piping welds. After the evaluation of susceptibility and consequences, a list of potential inspection locations will be developed. Actual inspection locations will be selected on the basis of physical accessibility, exposure levels, and availability of nondestructive examination techniques. If destructive examination is employed, the ASME Code, Section XI rules for repair and replacement will be used to return piping to its original condition. The small-bore piping inspection is a one-time inspection. Any unacceptable indication of cracking of piping welds requires that an engineering analysis be performed to determine proper corrective action including implementation of an AMP is necessary. Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program including implementation of an aging management program as appropriate. The small-bore piping inspection program will be implemented by plant procedures in accordance with the Duke

Quality Assurance Program. With respect to the inspection timing, the applicant stated that this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable. If present, cracking of small-bore piping welds may not be fully managed by the current ASME Section XI examinations. However, based on industry experience, cracking of small-bore piping should be minimal. Thus, the staff finds the use of a one-time inspection adequate.

The staff concludes that the RCS small-bore piping inspection program will verify whether there is a need to manage aging effects so that the structural integrity of the piping is maintained during the period of extended operation.

Program to Inspect HPI Connections to the RCS

The AMP for the high-pressure injection (HPI) nozzles connecting pipe and thermal sleeves is identified in the response to RAI 4.22-1. This program is a continuation of the program begun during the initial license term to manage the aging effects of the HPI connection to the RCS. The inspections are based on ASME Code Section XI requirements and Duke's commitments in response to GL 85-20 and Inspection and Enforcement Bulletin (IEB) 88-08 "Thermal Stresses in Piping Connected to Reactor Coolant Systems," and in a letter from Duke dated January 7, 1998. These commitments are to perform ultrasonic inspection to meet the requirements of Appendix VIII of ASME Code Section XI, 1992 Edition with 1993 Addenda, or to develop procedures through the use of mockups containing thermal-fatigue cracks.

Flaws in weld or base metal which cannot be accepted based on geometry screening or the fracture analysis methods of the ASME Code are corrected by repair or replacement. Any increase in the size of the gap between the thermal sleeve and the safe end is corrected by repair or replacement.

Based on the above, the staff finds that the inspection program for the HPI lines is adequate for detecting cracks in the piping and nozzles and the growth of a gap between the thermal sleeve and the safe end.

Cast Austenitic Stainless Steel (CASS) Flaw Evaluation Procedure

The loss of fracture toughness in CASS valve bodies was previously reviewed by the staff in a safety evaluation for BAW-2243A. The aging management approach described in the topical report, and agreed to by Duke, combines periodic inservice inspection required by ASME Code Section XI, Subsection IWB, for valve bodies (i.e., Examination Categories B-M-1 and B-M-2) with the flaw evaluation procedure specified in IWB-3640. The staff approved this approach in the SER for the topical report.

Aging Management Programs for the Pressurizer

The programs that are used to manage the applicable aging effects of the pressurizer, except for the pressurizer examinations, are evaluated in Section 3.2 of this SER. The pressurizer examinations are evaluated below.

Pressurizer Examinations

In the SE of BAW-2244, Renewal Applicant Action Item 4.2(1) identified the following aging effects that would require new or additional inspections for license renewal: (1) cracking of pressurizer cladding, including items attached to the cladding (e.g., tripod legs), that may result in cracking or loss of underlying ferritic steel; (2) aging management of the structural welds that connect the heater sheaths to the diaphragm plates; and (3) cracking of small bore nozzles and safe ends. In addition, the ONS-specific review determined that the internal spray line and spray head required a one-time inspection to detect cracking.

Aging management of the pressurizer Alloy 600 small- bore nozzles is addressed in the Alloy 600 management program. Small-bore safe ends are addressed in the small-bore piping inspections. The pressurizer examinations include two specific examinations: (1) the pressurizer cladding, internal spray line, and spray head examinations; and (2) the pressurizer heater penetration weld examination, described below:

Pressurizer Cladding, Internal Spray Line, and Spray Head Examination
Duke proposed an AMP with the following characteristics for the pressurizer cladding, internal spray line, and spray head. The method of examination and acceptance criteria will be visual examination (VT-3) to ASME Code Section XI requirements. The examination covers the pressurizer, the internal spray line, the spray head, and the fasteners that are used to attach the spray line to the internal surface of the pressurizer. The clad examination will focus on the cladding adjacent to the heater bundles since historical data indicates cracking may occur adjacent to the heater bundles. This one-time inspection will be performed on one pressurizer by February 6, 2013 (the end of the initial license of ONS Unit 1). The staff finds this inspection schedule acceptable. If present, cracking of the cladding, cracking of the internal spray line, and cracking of the spray head, is a slow acting mechanism; thus, the staff expects minimal cracking, if any, and finds the use of a one-time inspection adequate.

The corrective actions are as follows:

- If cracks are detected in the cladding that extend to the underlying ferritic steel, acceptance standards for Examination Categories B-B and B-D may be applied to the ferritic steel.

- If cracks are detected in the internal spray piping, acceptance standards for Examination Category B-J may be applied.

- If cracks are detected in the spray head, engineering analysis will determine the corrective action which could include replacement of the spray head.

- The need for subsequent examination will be determined after the results of the initial examination.

In response to RAI 4.3.7-1, Duke stated that cracking of stainless steel cladding, including attachment welds to cladding, is not an applicable aging effect for the period of extended operation. The basis for this conclusion was that the Haddam Neck pressurizer in which cracking of cladding was previously observed was significantly different from the ONS pressurizer. The staff believes cracking of the cladding, including attachment welds to cladding, is an aging effect needing additional evaluation. However, the one-time examination of the pressurizer cladding and attachment welds will verify whether this aging effects warrants an aging management program.

Pressurizer Heater Bundle Penetration Welds Examination
For the heater bundle penetration welds, the examination method and acceptance criteria will be to ASME Code Section XI requirements and will include:

- a surface examination of 16 peripheral welds on the first removed heater bundle;
- a visual examination (VT-3 or equivalent) of the remaining welds of the heater bundle;
- an inspection of the heater bundle welds to Examination Category B-E during the fifth inservice inspection interval.

The surface examination will be a one-time inspection performed when a heater bundle is removed. If the results are not acceptable, they may be used as a baseline for establishing a longer term programmatic action covering all ONS pressurizer heater bundles. Open Item 3.4.3.3-1 requested that Duke identify the schedule for the heater bundle examination. In response, Duke stated that the heater bundle examination will occur not on a fixed schedule, but when a heater bundle is replaced due to inoperable heater elements. This position is justified by Duke due to the unreasonableness of removing a functional heater bundle assembly and due to the ability of the current leakage monitoring program to easily detect leakage from the structural welds that attach the heater sheath to the heater sleeve and the heater sleeve to the diaphragm plate. Leakage from these welds would be within the make-up system capacity and leakage would not compromise the integrity of the heater bundle bolted closure and the function of the pressurizer. The staff concurs with this assessment and thus, closes Open Item 3.4.3.3-1.

For ONS Unit 1, Duke proposed in the LRA, to inspect the heater-sheath-to-sleeve penetration welds, but not the heater-sleeve-to-heater-bundle diaphragm plate. The ONS Unit 1 heater sleeves and heater bundle diaphragm plates are fabricated from Alloy 600, which is susceptible to PWSCC. Hence, both the heater-sheath-to-sleeve plate and the heater-sleeve-to-bundle diaphragm plate need to be inspected to determine whether the Alloy 600 materials in the heater bundle have experienced PWSCC. The heater sheaths and heater bundle diaphragm plates in

ONS Units 2 and 3 are stainless steel. Therefore, they are not susceptible to PWSCC. The ONS Unit 1 heater bundles are susceptible to PWSCC and the ONS Unit 2 and 3 heater bundles are not. Open Item 3.4.3.3-2 requested that the scope of the Unit 1 heater bundle inspection be expanded to include inspections of both the heater sheath-to-heater sleeve structural weld and the heater sleeve-to-heater bundle diaphragm plate structural weld. Unit 1 is the subject of this one-time inspection due to the fact that the Unit 1 heater sleeves and heater bundle diaphragm plates are fabricated from Alloy 600, and hence subject to PWSCC, whereas those in Units 2 and 3 are stainless steel and are not susceptible to PWSCC. Duke agreed to this revision. Therefore, Open Item 3.4.3.3-2 is closed.

The staff concludes that Duke has acceptable AMPs for managing the aging effects for the pressurizer heater bundle penetration welds, cladding, spray line, and spray head.

Aging Management Programs for the Reactor Vessel

Pressure-Temperature (P-T) Limits

P-T limits are discussed in Section 4.2.4.3.1 of this SER, "Reduction of Fracture Toughness."

Reactor Vessel Materials Surveillance Program

Criteria are specified in 10 CFR Part 50, Appendix H, "Reactor Vessel Materials Surveillance Program," for monitoring changes in the fracture toughness properties of ferritic materials in the reactor beltline region as a result of the exposure of the materials to neutron irradiation and a thermal environment. Appendix H requires that the surveillance program design and withdrawal schedule meet the requirements of American Society for Testing Materials (ASTM) E-185, "Standard Practice for Conducting Surveillance Tests for Light Water Cooled Nuclear Power Vessels."

The NRC accepted the technical basis for an integrated surveillance program with regard to design and operating conditions by approving BAW-1543, Revision 4, including Supplements 1 and 2, "Master Integrated Reactor Vessel Surveillance Program" (MIRVP), to demonstrate continuous management of these aging effects. The NRC stated that the MIRVP met the requirements of Appendix H with respect to design and withdrawal schedules for an integrated surveillance program (Appendix H, paragraph III.C). In a letter dated July 11, 1997, the staff approved the withdrawal schedules for all plants included in BAW-1543, Revision 4, Supplement 2, which covers ONS Units 1, 2, and 3. However, the staff approval was for a 40-year license term.

The integrated surveillance program approved by the staff consists of three elements: (a) plant-specific capsules, (b) supplementary weld metal surveillance capsules (SUPCAPS) and (c) high-fluence supplementary weld metal surveillance capsules (HUPCAPS). Each licensee participating in the integrated surveillance program has provided at least six plant-specific capsules to the program. There are six SUPCAPS with the target fluence for the capsules varying from 6.1x 10^{18} n/cm^2 to 1.6 x 10^{19} n/cm^2. There are eight HUPCAPS with the target fluence varying from 1.3 x 10^{19} n/cm ^{2} to 2.4 x 10^{19} n/cm^2. According to Duke, the integrated surveillance program will provide sufficient data to monitor the effects of radiation on the ONS units.

Duke states that the data obtained during the current term of operation will be valid for the period of extended operation provided the technical bases for the integrated program, as discussed in Chapter 4.0 of BAW-1543, Revision 4, are not violated during the period of extended operation. In order to ensure that the MIRPV data remains valid for the period of extended operation, the following activities will be conducted by Duke through the ONS Reactor Vessel Integrity Program, as described in Section 4.24 of Exhibit A of the LRA and in response to RAI 3.4.5-7:

- Neutron fluence at the inside surface of the reactor will be monitored physically or analytically during the period of extended operation to ensure that the capsule data obtained during the current term of operation remains valid during the period of extended operation. Descriptions of the ONS Cavity Dosimetry Program and the ONS Fluence and Uncertainty Calculations are provided in Sections 4.24.2 and 4.24.3 respectively, of Exhibit A of the LRA. The Cavity Dosimetry Program included ex-vessel cavity dosimetry for Unit 2. Since Units 1 and 3 do not have ex-vessel cavity dosimetry, the dosimetry from Unit 2 will be used to monitor the neutron fluence of all three units. Based on the similarity of the reactor pressure vessels, this is acceptable.

- Modifications to the design and operation of the plant that result in changes to the neutron energy spectrum relative to BAW-1543, Revision 4, will be compared to the energy spectrum in which the capsules were irradiated. If applicable, the current term surveillance data will be adjusted for the subsequent radiation effects on materials evaluations (embrittlement effects) due to the revised neutron spectrum. Duke has stated that these requirements will be added to the "Acceptance Criteria or Standard" section of the LRA.

- Modifications to the design and operation of the plant that result in changes to the gamma heating, relative to BAW-1543, will be accounted for in the subsequent effect on the applicable embrittlement evaluations for the reactor materials. Duke has stated that this requirement will be added to the "Acceptance Criteria or Standard" section of the LRA.

- Modifications to the design and operation of the plant, that result in changes to the reactor inlet temperature relative to BAW-1543, will be assessed as to their subsequent effect on the embrittlement of the reactor materials. Duke has stated that this requirement will be added to the "Acceptance Criteria or Standard" section of the LRA.

Duke has provided assurance that the parameters discussed above will remain valid during the period of extended operation since the NRC-approved Reactor Vessel Integrity Program described in Section 4.24 of Exhibit A of the LRA will confirm that the fracture toughness tests will remain valid during the period of extended operation. This commitment in the UFSAR supplement is acceptable to the staff.

Duke has further stated that the data needed for the period of extended operation either has already been obtained and tested or will be obtained by the end of Cycle 17 at Davis-Besse (DB) Unit 1 or Crystal River (CR) Unit 3. Duke estimates that Cycle 17 at DB Unit 1 and CR Unit 3 will occur approximately in 2008 – 2010, which is during the current term of operation for the ONS units. Duke determined the target fluences for the capsules and compared them with the expected peak 48 EFPY fluence estimate at the inside surface of the RV, to confirm that the necessary data for the period of extended operation will be obtained during the current period of operation.

Duke has recalculated the neutron fluence at the end of extended life for the ONS units, and projects that all three units will be below the PTS screening criteria at the end of the renewal period. Since Duke will continue to use low-leakage cores, monitor industry activities, and periodically update its PTS evaluations, neutron embrittlement will be adequately managed during the period of extended operation as stated in Section 5.4.2.1 of Exhibit A to the LRA. This is also discussed in Section 4.2.4 of this SER.

<u>Aging Management Programs for the Vessel Head Penetration (VHP) Nozzles</u>

The evaluations of the Boric Acid Wastage Surveillance Program, the Water Chemistry Control Program, the Inservice Inspection Program, and the RCS Operational Leakage Monitoring Program are presented in Sections 3.2.1, 3.2.2, 3.2.5, and 3.2.7 of this SER. This section provides the staff's evaluation of the CRDM Nozzle and Other Vessel Closure Head Penetrations Inspection Program.

The regulatory basis for the ONS CRDM Nozzle and Other Vessel Closure Head Penetrations Inspection Program is presented in Generic Letter 97-01, "Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations." In this GL, the staff requested that addressees provide a description of their plans to inspect the vessel head penetrations (VHPs) at their plants. Duke states that the program includes the CRDM penetration nozzles of all three ONS units and the thermocouple nozzles at ONS Unit 1. These VHPs are fabricated from Inconel 600 (Alloy 600). Duke's description of the CRDM Nozzle and Other Vessel Closure Head Penetrations Inspection Program is consistent with its responses to GL 97-01, dated July 30, 1997, and December 21, 1998. Duke stated that it is a member of the B&WOG and an active participant in the B&WOG/NEI integrated program for assessing the potential for PWSCC to occur in the VHPs of PWR-design plants. The staff approved the NEI/BWOG integrated program for VHPs on March 21, 1999 (see Letter from J.R. Strosnider (USNRC) to D.J. Modeen (NEI), "Review of Generic Response to the NRC Requests for Additional Information Regarding

Generic Letter 97-01," dated March 21, 1999). Based on the above, the staff concludes that the implementation of CRDM Nozzle and Other Vessel Closure Head Penetrations Inspection Program, together with the integrated program and the generic efforts by NEI, will provide an acceptable basis for managing the effect of PWSCC in the VHPs during the period of extended operation.

Aging Management Programs for the RV Internals

The following AMPs are used to manage aging of the reactor vessel internals: (1) The Inservice Inspection Plan (Examination Category B-N-3), and (2) The Oconee Reactor Vessel Internals Inspection.

(1) Inservice Inspection Plan (Examination Category B-N-3)

In Table 3.4-1 of the LRA, this program is cited for managing loss of material, cracking (due to IASCC and SCC), reduction of fracture toughness (due to thermal embrittlement and neutron irradiation embrittlement), and loss of closure integrity of the RVI components. Examination Category B-N-3 in Section XI of the ASME B&PV Code calls for a VT-3 examination of portions of the removable core support structures. IWA-2213 of Section XI of the ASME Code states that VT-3 examinations are conducted to determine the general mechanical and structural condition of components and their supports, and to detect discontinuities and imperfections, such as loss of integrity at bolted or welded connections, loose or missing parts, debris, erosion, wear, or corrosion. This existing program is adequate to manage the loss of material because the VT-3 examination is capable of detecting loss of material. However, for the other aging effects, the VT-3 examination is not sufficiently sensitive to the degradation expected from the aging effects as described below.

(2) Oconee Reactor Vessel Internals Inspection

In the original application, Duke described a proposed ONS Reactor Vessel Internals AMP (RVIAMP). This program was intended to evaluate the need for inspections of reactor vessel internals components through investigation of applicable aging effects; develop the scope, methods, frequency, acceptance criteria and timing of inspections of RVI components; and, implement the inspection programs as required. Duke has since taken the essential elements of the ONS RVIAMP and reconfigured them as the Oconee Reactor Vessel Internals Inspection.

The scope of this inspection program covers cracking due to irradiation-assisted stress corrosion cracking and SCC, reduction of fracture toughness due to irradiation embrittlement and thermal embrittlement, dimensional changes due to void swelling, and loss of closure integrity due to stress relaxation. This program includes participation in industry programs to investigate these aging effects, inspections, and reports. Within this program Duke has committed to participate in the B&W Owners Group Reactor Vessel Internals Aging Management Program and other industry programs, as appropriate. Reports would be provided to the NRC on a periodic basis after completion of significant milestones, commencing within one year after the issuance of the renewed license. A final report will also be submitted by Duke at or near the end of the initial license period for Unit 1, which will be at least two years prior to the first inspection of RVI components at Oconee. The final report will contain the test results from the RVIAMP and the recommended inspection program for the RVI. Based on the information developed from the RVIAMP, the applicant will implement an aging management program for the RVI.

As described by Duke, the Reactor Vessel Internals Inspection encompasses three groups of components. These groups are: baffle bolts; CASS and martensitic steel components; and, effectively, all other components, including plates, forgings, welds, and other bolting (core barrel bolts and thermal shield bolts).

For the baffle bolts, the applicable aging effects are cracking due to IASCC, reduction of fracture toughness due to irradiation embrittlement, and change of dimensions due to void swelling. The number of baffle bolts needed to be intact and their locations will be determined by analysis. Current plans for the baffle bolts are for a volumetric examination, with any detectable crack indication considered unacceptable. Acceptance criteria for change of dimensions will be determined by analysis prior to initiation of the inspection program.

For the CASS and martensitic steel components (including the control rod guide tube spacers, vent valve bodies, outlet nozzles for Unit 3, incore guide tube assembly spiders, and the vent valve retaining rings), the applicable aging effects are reduction of fracture toughness due to irradiation embrittlement and thermal aging embrittlement. Since the reduction of fracture toughness cannot be quantified through non-destructive examination, the specific inspection method to be used will be determined based upon analyses to determine the critical flaw size given the service loading conditions and the service-degraded material properties. The Oconee Unit 3 outlet nozzles will be inspected if the results of the analyses indicate such inspection is necessary.

For other RVI components, including plates, forgings, welds, and bolting other than baffle bolting, the applicable aging effects are cracking due to irradiation-assisted stress corrosion cracking, reduction of fracture toughness due to irradiation embrittlement, dimensional changes due to void swelling, and loss of bolted closure integrity due to stress relaxation. The inspection method(s) and acceptance criteria will be determined by analysis prior to initiation of the inspection program.

This inspection program encompasses the reactor vessel internals at each of the Oconee units. Duke proposed one inspection at each unit, with the first inspection to occur early in the license renewal period, the second near the middle of the license renewal period and the third in the latter third of the license renewal period, prior to the last year of the license renewal period.

Aging Management Review

This inspection program is acceptable due to the targeting of pertinent components with appropriate inspection methods, in a time frame that will provide useful results throughout the entire license renewal period.

Open Items 3.4.3.3-3 through 3.4.3.3-6 dealt with various aspects of the Oconee RVIAMP, including inspections to manage cracking of non-bolting RVI components, inspection plans to manage degradation of baffle bolts, and aging management for CASS RVI components. The revisions to the aging management program as embodied in the Oconee Reactor Vessel Internals Inspection program are sufficient to close Open Items 3.4.3.3-3 through 3.4.3.3-6.

The staff concludes that the Oconee Reactor Vessel Internals Inspection program provides sufficient data and analyses to demonstrate adequate management of aging effects for the reactor vessel internals such that their intended function will be maintained consistent with the CLB for the period of extended operation, in accordance with 10 CFR 54.21(a)(3).

Aging Management Programs for the Steam Generators

Section 3.4.7.1 of Exhibit A of the LRA states that the OTSG is designed to accommodate all service loadings (i.e., levels A through D); however, operation under levels A and B service conditions contributes to the normal aging stresses for the OTSG items. The ONS units have not been subjected to level C or D events. It is the staff's understanding that the tubes in ONS Unit 3 were subjected to stresses slightly beyond the allowable values during an event in August 1994, involving the injection of cold feedwater into a hot, dry SG. In RAI 3.4.7-1, the staff requested Duke to discuss whether or not this event contributed to the aging of the SG tubes. In addition, Duke was requested to describe the procedures that are used to evaluate the effect of such events on the adequacy of the AMPs.

In its response, Duke stated that the Unit 3 event that occurred on August 10, 1994, was a reactor trip from full power that resulted in the dryout of the B OTSG. The overcooling that occurred as a result of the inadvertent opening of a turbine bypass valve resulted in tube-to-shell temperature differentials in excess of established tube-to-shell limits. A reactor trip is an upset event (i.e., level B) and is not an emergency or faulted event (level C or D). According to Duke, a subsequent evaluation by B&W using actual transient data indicated that the axial tube loads (both compressive and tensile) were within the limits of the allowable tube loads. Since the allowable tube loads were not exceeded, the event of August 10, 1994, did not affect the integrity of the B OTSG tubes. According to Duke, this event was determined to have a minimal effect on the aging of the steam generator tubes, and modifications to AMPs are not necessary. However, it was the staff's understanding that there was uncertainty associated with the actual transient data and therefore potential for damage to tubes could not be ruled out.

In RAI 3.4.7-1, Duke was requested to provide clarification on this issue and the basis for its conclusion that the loads associated with the August 10, 1994, event did not jeopardize the structural integrity of the tubes. The B&WOG has recommended some changes in the operating procedures to manage such events in the future. The staff requested Duke to verify whether or not such changes had been incorporated in the plant procedures at Oconee. In its response, Duke confirmed that there was uncertainty associated with the August 10, 1994, Oconee Unit 3 transient data because of an erroneous thermocouple reading and the compressive load limit may have been exceeded. However, Duke provided details of the evaluation to demonstrate that the compressive load associated with the August 10, 1994, event did not jeopardize the structural integrity of the tubes. In evaluating the integrity of the tubes, Duke replaced the erroneous thermocouple reading with the lowest of the two thermocouples directly above the affected thermocouple (i.e., A0976-454 °F), and the average shell temperature and tube-to-shell differential were recalculated. The maximum tube-to-shell differential, which occurred at 12:05 p.m., on August 10, 1994, was reduced from 82 °F to 66 °F. The compressive limit of +60 °F was exceeded by 6 °F, and a structural evaluation was performed prior to the restart of the unit. The maximum tube-to-shell differential of 66 °F was used in the structural evaluation and the resulting maximum axial tube load was lower than the maximum compressive load for a design basis heatup (i.e., 100 °F/hr). Based on this result, it was concluded that the tube compressive load associated with the August 10, 1994 event did not jeopardize the structural integrity of the tubes.

Subsequent to the August 10, 1994, event the Oconee Emergency Operating Procedures (EOPs) were reviewed and the following changes were made. A caution was added to Section 502 (Loss of Heat Transfer) and Section 503 (Excessive Heat Transfer) that will alert Operators to the possibility of exceeding the compressive tube-to-shell limit of 60 °F should a significant delay occur in reestablishing feed to a dry and intact OTSG. In addition, a training package was issued to inform all licensed personnel of the change to the EOPs.

The staff notes that several OTSGs have in the past been subject to dryout, and no direct consequences to tube degradation have been attributed to such events. The staff considers the applicant's existing aging management programs in place to manage degradation of the steam generator tubes adequate to provide reasonable assurance that aging effects will be managed for the period of extended operation.

The installation of sleeves in SG tubes causes a distortion of the tube at the expansion joint of the sleeve. The increased stress in the tube makes it susceptible to circumferential cracking at this location. In RAI 3.4.7-2, Duke was requested to discuss whether current measures to manage this aging effect during plant operation are adequate to manage anticipated further aging during the extended period of operation of the SGs. If additional measures were planned to deal with this aging mechanism during the license renewal period, Duke was requested to identify and discuss such measures in detail.

In its response, Duke stated that present eddy current inspection methods were sufficient to detect circumferential cracking of the tubes in the regions adjacent to the expansion joint between the sleeve and the tube. The inspection method employs a bobbin coil throughout the entire tube length to identify crack-like indications. For regions of geometric discontinuities, such as the roll expansion in the tube sheet region and the roll expansions in the sleeve, a more sophisticated eddy current inspection technique is employed (e.g., a rotating coil probe). Flaws that exceed the acceptance criteria in the TSs are identified as defects. The affected tube may then be plugged or repaired using an alternate repair criterion, as discussed in the technical specifications. The current inspection methods and subsequent evaluation procedures are sufficient for both the current term of operation and the period of extended operation with respect to inspection of the regions adjacent to the expansion joint between the sleeve and the tube. SG tube inspections are performed at ONS in accordance with the steam generator tube surveillance program, which is described in Section 4.26 of Exhibit A of the LRA and evaluated by the staff below. The staff finds Duke's response as discussed above, related to circumferential cracking of the SG tubes at expansion joints of the sleeves, reasonable and acceptable.

The staff's review of other aging management programs that apply to the steam generators, including the Boric Acid Wastage Surveillance Program, the Chemistry Control Program, the Inservice Inspection Plan, and the RCS Operational Leakage Monitoring may be found in Section 3.2, "Common AMPs," of this SER. The staff's review of the Alloy 600 AMP may be found in Section 3.4.3.3 of this SER. The staff's evaluation of the Steam Generator Tube Surveillance Program follows.

<u>Steam Generator Tube Surveillance Program</u>

The Steam Generator Tube Surveillance Program, in combination with ONS Improved Technical Specification 5.5.10, provides for comprehensive examinations of the steam generator tubes, sleeves, and plugs to identify and repair degraded conditions before the degradation exceeds allowable limits.

Program Scope
In accordance with ASME Section XI requirements and its improved technical specifications (ITS), Duke inspects the ONS steam generator tubes during each unit's refueling outage. The number of steam generator tubes, sleeves, and plugs to be examined each outage meet, at a minimum, its TS requirements. Duke stated their program complies with all the guidance of NEI 97-06, "Steam Generator Program Guidelines," and the EPRI standards referenced in NEI 97-06. In practice, Duke exceeds the requirements in the ITS because the EPRI guidelines are more comprehensive than the ITS. The staff considers the scope of Duke's inspection program acceptable because it meets both Duke's ITS and current industry guidelines, and is adequate to detect steam generator tube degradation.

Preventive/Mitigative Actions
No preventive or mitigative actions are associated with this test procedure, and the staff did not identify a need for any.

Parameters Monitored
Duke applies nondestructive test techniques, primarily eddy current testing, to detect cracking of the steam generator tubes, sleeves, and plugs. In its LRA, Duke follows EPRI's "PWR Steam Generator Examination Guidelines" with respect to eddy current testing. These guidelines provide, among other things, criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data (including the procedure, probe selection, analysis protocol, and reporting criteria). Following the EPRI guidelines, Duke performs the appropriate type of eddy current test technique depending on the region of the steam generator (e.g., top of the tubesheet, freespan) and whether the tube is sleeved or plugged. The staff considers the parameters monitored (e.g. the eddy current test results) acceptable because operating experience has demonstrated that the data obtained from these nondestructive examinations, when applied in accordance with the EPRI guidelines, provide reasonable assurance that the effects of aging on steam generator tubes, sleeves, and plugs will be detected.

Detection of Aging Effects
As discussed above, Duke has described an acceptable scope, inspection frequency and test technique to detect aging effects in SGTs, sleeves and plugs. Industry and ONS experience to date indicates that Duke performs eddy current testing in a manner expected to ensure continued tube integrity, and that aging effects will be discovered and repaired before there is a loss of intended function.

Monitoring and Trending
Duke monitors tube degradation from cycle to cycle as part of its commitment to NEI 97-06. The condition monitoring program applied at ONS uses inspection results to ensure that steam generator tube integrity has been maintained over the past operating cycle. Duke also considers the inspection results in its operational assessment for the upcoming cycle to ensure that the tubes will perform their intended function.

Acceptance Criteria
Duke categorizes tube degradation in accordance with its TS. Tubes with indications sized at greater than or equal to 20 percent of the nominal wall thickness are considered "degraded." Tubes with indications sized at greater than the plugging or repair limit are considered "defective" and must be plugged or repaired. Duke defines its plugging or repair limits in its ITS. For tubes or sleeves, eddy current indications sized at greater than or equal to 40 percent of the original nominal tube wall thickness are considered defective. The staff considers Duke's acceptance criteria acceptable because they are based on Duke's ITS, which are in turn based on ASME criteria which the staff endorses.

Operating Experience
Although it is not discussed explicitly in the LRA, the staff is aware through licensee event reports that Duke experienced tube degradation that led to three relatively recent, unplanned shutdowns of ONS units (two in 1994 and the third in 1997). Duke shut down the affected units

because of excessive steam generator leakage during operation, and performed additional inspections of the tubes. Duke determined fatigue was the cause of the degradation in the 1994 outages; cracked seal welds and leaking plugs led to the shutdown in 1997. In both cases, Duke applied appropriate corrective actions, such as enhanced eddy current inspections and tube repairs, that demonstrated an appropriate response to steam generator tube degradation. Thus, the staff finds Duke's operating experience to date, supports its conclusion that its Steam Generator Tube Surveillance Program is effective.

In conclusion, the staff finds the combination of AMPs discussed in this section and Section 3.2 of this SER provides reasonable assurance that aging effects for steam generators will be adequately managed to ensure the intended function of the steam generators will be maintained consistent with the CLB for the period of extended operation.

Aging Management Programs for the Reactor Coolant Pump (RCP)

Open Item 3.4.3.3-7 was concerned with the aging management of CASS components such as RCP casings and covers, which were susceptible to loss of fracture toughness by thermal aging embrittlement. Duke has stated that the aging effects for the RCP casings, covers and pressure-retaining bolting can be managed during the license renewal term by its inservice inspection plan and will be supplemented by flaw evaluation procedures for CASS. For RCP casings and covers, which are susceptible to loss of fracture toughness by thermal aging embrittlement, aging management is accomplished through the application of ASME Code Case N-481 for the RCPs of Units 2 and 3. For the Unit 1 RCPs, the ASME Code Case has not been invoked. For such cases, Duke has indicated that it will determine susceptibility of the pump casing using the screening criteria of EPRI TR-106092, as supplemented by the following:

- Statically cast components with a molybdenum content exceeding the requirements of SA-351 Grades CF3 and CF8 and with a delta ferrite content less than 10 percent will not need supplemental examination.
- Ferrite levels must be calculated using Hull's equivalent factors or a method producing an equivalent level of accuracy (±6 percent deviation between measured and calculated values).
- Cast stainless steel components containing niobium are subject to supplemental examination.

Susceptible RCP casings would be managed through inspection in accordance with ASME Code Section XI.

This aging management program for RCP covers and casings is acceptable because the program will ensure that degradation will be identified and remediated in a timely manner. Thus, Open Item 3.4.3.3-7 is closed.

Reactor Coolant Pump Fatigue

The RCP items that are susceptible to fatigue are those items for which cumulative usage factors were calculated in the original design. A fatigue analysis was performed for the main flange bolts for the Westinghouse pumps at ONS Unit 1; the casing, cover, and flange met the exemption from fatigue requirements and were not analyzed for fatigue. A fatigue analysis was performed for the casing, studs, wear ring, and cover/stuffing box for the Bingham pumps at ONS Units 2 and 3. Demonstration of the acceptability is addressed in Section 5.4.1.1 of Exhibit A of the LRA and by the thermal fatigue management program described in Section 5.4.1.3 of Exhibit A of the LRA. The staff finds the applicants fatigue evaluation of the RCP items acceptable based on the staff's acceptance of the fatigue management program which is addressed in Section 4.2.3 of this SER.

Aging Management Programs for the Control Rod Drive Mechanism Motor Tube Housing (CRDMMTH)

Duke has stated that continued implementation of the following programs will be used to monitor and inspect for, either directly or indirectly, the identified effects of aging on the ONS CRDMMTH: (1) the ONS Chemistry Control Program, (2) the ONS Inservice Inspection Plan, and (3) the ONS RCS Operations Leakage Monitoring Program. These programs are evaluated in Section 3.2 of this SER.

Aging Management Programs for the Letdown Coolers

Duke implements the ONS RCS Operations Leakage Monitoring Program and the chemistry control program as AMPs for the letdown coolers. For the staff's evaluation of those programs, see Section 3.2 of this SER.

In RAI 3.4.10-1, the staff requested Duke to describe the repairs which were performed on the damaged letdown coolers and the specific analyses which were performed to assure that thermal and vibrational stresses during normal and off-normal operation will not cause fatigue failure during the period of extended operation. In its response, Duke stated that the letdown coolers are of the shell and spiral tube design. A review of operational history identified some events in which the tubes cracked because of thermal and vibrational stresses from improper operation of the coolers. Improper operation is defined as operation beyond the established design parameters.

Of the six coolers, two were replaced and four were repaired by plugging the cracked tube to remove them from service. Operational procedure changes were made to ensure operation within specified design parameters. Since adjustments were made to the plant operational procedures, the letdown coolers have not experienced any cracking due to thermal or vibrational stresses. Duke believes that this operating experience is significant in that it demonstrates that the tube cracking was operational and not age-related because operation within the coolers' design parameters precludes damage to the letdown cooler tubing from thermal or vibrational stresses. The staff concludes that no further analyses are considered necessary for the two new replaced coolers.

Loss of material and cracking (not thermal or vibration-induced) are identified in Section 3.4.10.2 as the applicable aging effects for the letdown coolers. These aging effects are managed by the chemistry control program and RCS operational leakage monitoring. The applicant is requested to provide its evaluation of the damage to the various components of the letdown coolers or the specific analyses performed to assure that the four repaired coolers have experienced no degradation as a result of improper operation. Further, the applicant is requested to provide an analytical assessment to assure that the four repaired letdown coolers are operating in a condition that precludes potential failure due to thermal fatigue during the extended period of operation. The applicant's response did not address this aspect of the issue. Therefore, this was identified as Open Item 3.4.3.3-8.

The applicant responded to this open item in its letter dated October 15, 1999. The applicant stated that each letdown cooler contains thirty tubes. Loss of the letdown cooler component intended function occurs when five tubes are plugged. When a cooler has five tubes that require plugging, that cooler is retired from service and replaced. Only six leaks have occurred among the six coolers since the installation of the pluggable design. No installed cooler is close to the functional plugging limit. If a leak were to occur, leakage will be detected by reactor coolant system operational leakage monitoring and changes in the component cooling system chemistry parameters monitored by the Chemistry Control Program.

Due to radiological concerns, a cooler containing a leaking tube may be physically removed from service, replaced with a spare cooler, and repaired in the hot machine shop. The repaired cooler then becomes the spare. Management of aging effects on the letdown coolers in this manner will provide assurance that the coolers can perform their intended function through the period of extended operation.

The staff finds the applicant's assessment, as discussed above, reasonable and acceptable. On this basis, Open Item 3.4.3.3-8 is closed.

In RAI 3.4.10-4, the staff requested Duke to identify any modifications of the letdown coolers or related components which may affect the projected fatigue usage of the subcomponents of the letdown coolers during the extended period of operation. In its response, Duke stated that the letdown coolers are constructed to ASME Section III, Subsection ND, requirements on the tube-side, and ASME Section VIII, Division I, on the shell side. A fatigue evaluation that would establish a projected fatigue usage factor was not required by the ASME Code for the design of these coolers. Therefore, no modifications of the letdown coolers will affect the projected fatigue usage of the subcomponents of the letdown coolers during the extended period of operation.

Since letdown coolers and related components do not require fatigue analysis by the ASME Code, the staff finds Duke's response reasonable and acceptable.

3.4.3.4 Time-Limited Aging Analyses

The TLAAs for P-T limits, low-temperature over-pressure protection, pressurized thermal shock, Charpy upper-shelf energy, and intergranular separations under vessel weld cladding are covered in Section 4 of this SER.

3.4.4 Conclusion

The staff has reviewed the information included in the subject sections of Exhibit A, "License Renewal — Technical Information, OLRP-1001," of the LRA and additional information presented by Duke in response to the staff RAIs. On the basis of this review, the staff concludes that Duke has demonstrated that the effects of aging on the reactor coolant system will be adequately managed so that there is reasonable assurance that it will perform its intended function in accordance with the CLB during the period of extended operation.

3.5 Engineered Safety Features Systems

3.5.1 Introduction

Duke described its aging management review (AMR) of the containment heat removal system, the containment isolation system, and the emergency core cooling system (collectively called the engineered safety features systems) in Exhibit A, "License Renewal — Technical Information, OLRP-1001," to the license renewal application (LRA). The staff reviewed these sections of the LRA to determine whether the applicant has demonstrated that the effects of aging on the engineered safety features systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2 Summary of Technical Information in the Application

Sections 2.5.3, 2.5.4, and 2.5.5 of Exhibit A of the LRA describe the engineered safety features systems. These systems include the containment heat removal system, the containment isolation system, and the emergency core cooling system.

Containment Heat Removal System

The containment heat removal system consists of two subsystems: the reactor building cooling system cools the reactor building during normal plant operation and following a loss of coolant accident; the reactor building spray system removes heat and the fission product iodine from the containment atmosphere after a design-basis accident. In Table 2.5-3 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

Containment Isolation System

Ten subsystems provide a containment isolation function in addition to their primary functions. Containment isolation prevents uncontrolled or unmonitored releases of radioactive materials to the environment. The ten subsystems and their primary functions include the following: the breathing-air system provides air inside the reactor building for use by plant personnel; the component cooling system sends cooling water to various components in the reactor building; the demineralized water system sends demineralized water to equipment in the reactor building; the filtered water system sends filtered water to the equipment in the reactor building; the gaseous waste disposal system controls and minimizes releases of radioactive gaseous waste generated in the plant; the instrument air system provides compressed air to various components in the plant; the leak rate test system is used to perform periodic integrated leak rate tests and local leak rate tests for verifying pressure boundary integrity; the liquid waste disposal system collects, samples, and stores, evaporates, reclaims, reprocesses, or discharges liquid wastes; the nitrogen purge and blanketing system provides a nitrogen over-pressure on the core flood tanks and quench tanks, (the system is also used for fill and make-up to the core flood tanks from the high-pressure injection system and the chemical-addition system); the reactor building purge system purges the reactor building with fresh air. In Table 2.5-5 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their material of construction.

Emergency Core Cooling System

The emergency core cooling system contains three subsystems. The system as a whole functions to provide reactor core cooling and shutdown capability following a design-basis accident. The core flood system injects water directly into the reactor vessel when the reactor coolant system pressure drops below a certain level following an accident. The high-pressure injection system recirculates reactor coolant water for purification and supplies injection water to the reactor coolant pump casings during normal operation. During an emergency, this system sends borated water directly to the reactor vessel injection nozzles on low reactor coolant system pressure or high reactor building pressure. In addition, this system sends borated water to the reactor coolant pump seals and makes up for loss from either a primary-side leak or a secondary-side break. The low-pressure injection system removes decay heat during cold shutdown and refueling operations. As part of the emergency core cooling system, this system sends cooling water to the reactor after an intermediate or large loss-of-coolant accident. In Table 2.5-7 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their material of construction.

3.5.2.1 Effects of Aging

In Sections 3.5.3, 3.5.4, and 3.5.5 of Exhibit A of the LRA, the applicant described the environments, materials, and associated aging effects for the containment heat removal systems, the containment isolation system, and the emergency core cooling systems. These sections also reference the associated aging management programs that are described fully in Section 4 of Exhibit A of the LRA.

Containment Heat Removal System — Aging Effects From Internal Environments

The reactor building cooling system consists of aluminum, stainless steel, and galvanized steel components exposed internally to ventilation air. The reactor building cooling system also has cooling units fabricated from 90-10 copper-nickel tubes with copper tube fins and stainless steel headers. The cooling units are exposed to raw water through the tubes and to ventilation air through the ducts and on the outside of the tubes. The applicant identified loss of material as an applicable aging effect for the aluminum and galvanized steel ductwork and for the 90-10 copper-nickel tubes and copper fins exposed to ventilation air. The applicant identified loss of material and fouling as applicable aging effects for the 90-10 copper-nickel tubes and stainless steel headers exposed to raw water. In Table 3.5-1 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the reactor building cooling system.

The reactor building spray system consists of stainless steel components. The internal environment of the system consists of borated water upstream of the pump discharge check valves. Downstream of these check valves, to the spray rings, the system components are normally exposed to the reactor building atmosphere. However, these portions of the system are occasionally exposed to borated water during system testing. The applicant identified loss of material and cracking as applicable aging effects for the system. In Table 3.5-1 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the reactor building spray system.

Containment Isolation System — Aging Effects From Internal Environments

The breathing air system consists of stainless steel components exposed internally to an air environment. The component cooling system consists of carbon and stainless steel components exposed internally to a treated water environment. The demineralized water system consists of stainless steel components exposed internally to a treated water environment. The filtered water system consists of stainless steel components exposed internally to a treated water environment. The gaseous waste disposal system consists of stainless steel components exposed internally to nitrogen. The instrument air system contains both carbon steel and stainless steel components exposed internally to an air environment. The leak rate test system consists of carbon and stainless steel components exposed internally to an air environment. The liquid waste disposal system consists of stainless steel components exposed internally to a borated water environment. The nitrogen purge and blanket system consists of stainless steel components exposed internally to either nitrogen or borated water. The reactor building purge system consists of aluminum, galvanized steel, stainless steel, carbon steel, brass, and copper components exposed internally to an air environment. For those carbon steel components exposed to a treated water environment, the applicant identified loss of material as an applicable aging effect. For those stainless steel components exposed to either a treated water or borated water environment, the applicant identified loss of material and cracking as applicable aging effects. For those carbon and stainless steel components exposed to an air or nitrogen environment, the applicant did not identify any aging effects. In Table 3.5-2 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the containment isolation system and subsystems.

Emergency Core Cooling System — Aging Effects From Internal Environments

The core flood system consists of stainless steel components exposed internally to borated water. The core flood tank is fabricated from carbon steel clad with stainless steel and exposed internally to borated water with a pressurizing nitrogen cover. The tank nozzle is fabricated from a nickel-based alloy, Inconel, and is exposed internally to borated water. For these components and environments, the applicant identified loss of material and cracking as applicable aging effects. In Table 3.5-3 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the core flood system.

The high-pressure injection system consists of stainless steel and carbon steel components. All components exposed to borated water are fabricated from stainless steel, and the applicant identified loss of material and cracking as applicable aging effects. Portions of the reactor coolant pump (RCP) coolers and RCP seal return coolers are fabricated from both carbon and stainless steel and exposed to treated water. The applicant identified loss of material and cracking as an applicable aging effect for the stainless steel portions of the system exposed to treated water, but not the carbon steel portions of the system exposed to treated water. The upper portion of the stainless steel letdown storage tank is normally supplied with a hydrogen overpressure. The applicant identified no applicable aging effects for this material-environment combination. In Table 3.5-3 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the high pressure injection system.

The low-pressure injection system consists primarily of stainless steel components. The borated water storage tank is fabricated from carbon steel lined with an epoxy-phenolic coating. The decay heat removal coolers have stainless steel tubes, tubesheets and channel heads, and a carbon steel shell. Nearly all stainless steel components are exposed internally to a borated water environment, and the applicant identified loss of material and cracking as applicable aging effects. The upper portion of the storage tank is exposed to air, and the applicant identified loss of material as an applicable aging effect. The decay heat cooler shell, tubesheet, and tubes are exposed to raw water. For these materials in a raw water environment, the applicant identified loss of material and fouling as applicable aging effects. In Table 3.5-3 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the low-pressure injection system.

Aging Effects From External Environments

Nearly all the components in the containment heat removal system, the containment isolation system, and the emergency core cooling system are exposed externally to the reactor building environment or the auxiliary building environment, or both. For the external surfaces of the carbon steel components in these systems, the applicant identified loss of material as an applicable aging effect. A portion of the containment isolation system, specifically the liquid waste disposal subsystem, is embedded in concrete. The applicant identified no aging effects for the embedded carbon steel piping of this system. A portion of the emergency core cooling system, specifically the low-pressure injection subsystem, is exposed to the outside yard environment. The applicant identified loss of material as an applicable aging effect.

3.5.2.2 Aging Management Programs

To manage aging effects from internal environments, Duke identified the following aging management programs for the containment heat removal system:

- chemistry control program
- preventive maintenance activities
- heat exchanger performance testing activities
- reactor building spray system inspection

To manage aging effects from internal environments, Duke identified the following aging management programs for the containment isolation system:

- chemistry control program
- treated water system stainless steel inspection
- reactor building spray system inspection

To manage aging effects from internal environments, Duke identified the following aging management programs for the emergency core cooling system:

- chemistry control program
- preventive maintenance program
- heat exchanger performance testing activities
- service water piping corrosion program
- galvanic susceptibility inspection

- reactor coolant system operational leakage monitoring

To manage aging effects from external environments, Duke identified the following aging management programs for the engineered safety features systems:

- boric acid wastage surveillance program
- inspection program for civil engineering structures and components

Duke concluded these programs would manage aging effects in such a way that the intended function of the components of the engineered safety features systems would be maintained consistent with the current licensing basis (CLB), under all design loading conditions during the period of extended operation.

3.5.3 Staff Evaluation

Duke described its aging management review (AMR) of the containment heat removal system, the containment isolation system, and the emergency core cooling system (collectively called the engineered safety features systems) in Exhibit A, "License Renewal—Technical Information, OLRP-1001," 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 engineered safety features systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.3.1 Effects of Aging

<u>Containment Heat Removal System — Aging Effects From Internal Environments</u>

For the reactor building cooling system, the applicant stated that aluminum, stainless steel, galvanized steel, 90-10 copper-nickel, and copper components are exposed to a ventilation air environment. As discussed in Section 3.5.2.6 of Exhibit A of the LRA, for a ventilation air environment, loss of material from galvanic corrosion is an applicable aging effect if these materials contact a material with a high electrochemical potential in the presence of water. Loss of material from boric acid wastage is also an applicable aging effect if these materials are exposed to concentrated boric acid. The applicant stated that the 90-10 copper-nickel tubes and stainless steel headers are exposed to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, for the raw water environment, loss of material is an applicable aging effect for these materials from various forms of corrosion, including general corrosion, pitting, galvanic corrosion, and microbiologically influenced corrosion. Fouling is another applicable aging effect caused by the exposure to the untreated raw water.

For the reactor building spray system, the applicant stated that the stainless steel components are exposed to borated water and air environments. As discussed in Section 3.5.2.2 of Exhibit A of the LRA, loss of material and cracking caused by corrosion — specifically, pitting, stress corrosion cracking and intergranular attack — are applicable aging effects from the potential exposure to oxygen, halides, sulfates, and so forth. These aging effects are also applicable to the portion of the system normally exposed to air because these sections are exposed to an alternately wetted and dried environment, and halogens, sulfates, and other impurities may concentrate and create an environment conducive to pitting and stress corrosion cracking.

Containment Isolation System — Aging Effects From Internal Environments

For the ten subsystems in the containment isolation system, Duke stated that carbon and stainless steel piping, tubing and valves are exposed to a treated water environment. As discussed in Section 3.5.2.5 of Exhibit A of the LRA, for the treated water environment, loss of material from various forms of corrosion including general corrosion, galvanic corrosion, erosion corrosion and pitting is an applicable aging effect. The applicant stated that stainless steel components are exposed to a borated water environment. As discussed in Section 3.5.2.2 of Exhibit A of the LRA, for the borated water environment, loss of material and cracking are applicable aging effects from pitting, stress corrosion cracking and intergranular attack from the potential exposure to oxygen, halides, sulfates, etc., in the borated water system. For those carbon and stainless steel components exposed internally to either an air or nitrogen environment, the applicant stated no aging effects were applicable. The staff agrees no aging effects are applicable to the stainless steel components exposed to air. However, in Section 3.5.4 and Table 3.5-2, the applicant stated that there were no applicable aging effects for the carbon steel components exposed to air in the instrument air system, the leak rate test system and the reactor building purge system. In Open Item 3.1.1-1, the staff requested that the applicant provide additional information to support its conclusion that there are no aging effects for these carbon steel components exposed to an air environment, consistent with the applicant's description of the environment in Section 3.5.2.1 of Exhibit A of the LRA. On the basis of the discussion in Section 3.1.3.1.1 of this SER, Open Item 3.1.1-1, as it relates to an air environment, is closed.

Emergency Core Cooling System — Aging Effects From Internal Environments

For the three subsystems in the emergency core cooling system, the applicant stated that Inconel and stainless steel components and the lined carbon steel borated water storage tank are exposed to a borated water environment. As discussed in Section 3.5.2.2, for the borated water environment, loss of material and cracking from general corrosion, pitting, stress corrosion cracking, and intergranular attack are applicable aging effects from the potential exposure to moisture, oxygen, halides, sulfates, and so forth in the borated water system.

The applicant identified stainless steel and carbon steel components exposed to a treated water environment. As discussed in Section 3.5.2.5 of Exhibit A of the LRA, for the treated water environment, loss of material because of pitting of the stainless steel components, is an applicable aging effect. In Section 3.5.5 and Table 3.5-3 on page 3.5-114 of the LRA, the applicant did not identify any aging effects for the carbon steel heat exchanger shell exposed to treated water. The staff, however, considers that carbon steel is subject to general corrosion, galvanic corrosion and possibly erosion corrosion in a treated water environment. In Open Item 3.1.1-1, the staff requested that the applicant present the basis for concluding that no aging effects are applicable for this component. On the basis of the discussion provided in Section 3.1.3.1.5 of this SER, Open Item 3.1.1-1, as it relates to a treated water environment, is closed.

The applicant identified carbon steel and stainless steel components exposed to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, for a raw water environment, loss of material is an applicable aging effect for these materials because of various forms of corrosion, including general corrosion, pitting, galvanic corrosion, and microbiologically influenced corrosion. Fouling is also an applicable aging effect caused by exposure to untreated water. The applicant stated that Inconel and stainless steel components are exposed to either nitrogen or hydrogen environments. As discussed in Section 3.5.2.1 of Exhibit A of the LRA, there are no aging effects for these material-environment combinations. The applicant stated that the lined carbon steel borated water storage tank is exposed to air. In Section 3.5.2.1 of Exhibit A of the LRA, the applicant stated that loss of material is an applicable aging effect for carbon steel if the liner is damaged, thus exposing the carbon steel to the environment.

Aging Effects From Fatigue

On the basis of the staff's experience, degradation of piping systems (e.g., cracking of welds) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In RAI 3.5.4-1, the staff requested that the applicant discuss how this loading effect was considered in the aging review of the containment isolation system, and if this effect is excluded, present the basis for its exclusion. In its response to the RAI, the applicant stated that it had reviewed NRC generic communications, industry experience, and relevant ONS experience to identify the applicable aging effects for the structures and components subject to an AMR. The applicant also stated that cracking caused by vibration can be generally attributed to deficiencies in design, and vibration characteristically leads to cracking in a short period of time of operation when compared to the overall plant operational life. On the basis of its assessment, the applicant concluded that cracking from vibrational (mechanical or hydrodynamic) loads was not an applicable aging effect for the ONS structures and components subject to AMR. The staff concurs with the applicant's assessment and the conclusion that vibration is not an applicable aging effect for the containment isolation system. The staff considers this assessment and conclusion applicable also to the containment heat removal systems and emergency core cooling systems because the basis for excluding fatigue due to vibrational loading is generic to these systems.

With respect to fatigue from thermal cycling for the engineered safety features systems, the applicant considered it an applicable aging effect and evaluated thermal fatigue as part of a Time Limited Aging Analysis (TLAA). A description of the process by which the engineering analysis was performed, as it applies to the engineered safety features systems, appears in

Sections 5.4.1.1 and 5.5.1 of Exhibit A of the LRA. The staff's evaluation of that LRA section appears in Section 4.0 of the safety evaluation and is not discussed further here.

Aging Effects From External Environments

Nearly all the components in the containment heat removal system, the containment isolation system, and the emergency core cooling system are exposed externally to the reactor building environment or the auxiliary building environment or both. As discussed in Sections 3.5.2.7.1 and 3.5.2.7.2 of Exhibit A of the LRA, the reactor building environment can reach up to 130 °F with 100 percent relative humidity. The auxiliary building environment is heated and cooled, but there can be some air moisture. For these environments, loss of material from corrosion is an applicable aging effect; specifically, boric acid wastage, general corrosion, and galvanic corrosion for those components fabricated from aluminum, galvanized steel, 90-10 copper-nickel, copper and carbon steel. Boric acid wastage is an applicable aging effect because of the potential for exposure to concentrated boric acid through leaking borated water systems. General corrosion is an applicable aging effect for carbon steel if the materials are in contact with a moist air environment. Galvanic corrosion is an applicable aging effect for carbon steel when in contact with a material with a higher electrochemical potential in the presence of water. There are no applicable aging effects for Inconel or stainless steel components exposed to the reactor or auxiliary building environments.

The external surfaces of one subsystem of the containment isolation system, the liquid waste disposal system, has portions of the stainless steel piping and valves embedded in concrete. As discussed in Section 3.5.2.7.5 of Exhibit A of the LRA, there are no applicable aging effects for the components because of the presence of the protective concrete cover.

The external surfaces of one subsystem of the emergency core cooling system, the low-pressure injection subsystem, has carbon steel piping, valves, and tank exposed to the outside yard environment. As discussed in Section 3.5.2.7.3 of Exhibit A of the LRA, loss of material from general corrosion is an applicable aging effect for carbon steel in a yard environment.

Aging Effects — Summary and Conclusions

The staff has reviewed the information provided by the applicant regarding ONS-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.

3.5.3.2 Aging Management Programs for License Renewal

To manage aging effects caused by internal environments, Duke identified the following aging management programs for the containment heat removal system:

- chemistry control program
- preventive maintenance activities
- heat exchanger performance testing activities
- reactor building spray system inspection

To manage aging effects caused by internal environments, Duke identified the following aging management programs for the containment isolation system:

- chemistry control program
- treated water system stainless steel inspection
- reactor building spray system inspection

To manage aging effects caused by internal environments, Duke identified the following aging management programs for the emergency core cooling system:

- chemistry control program
- preventative maintenance program
- heat exchanger performance testing activities
- service water piping corrosion program
- galvanic susceptibility inspection
- reactor coolant system operational leakage monitoring

To manage aging effects caused by external environments, Duke identified the following aging management programs for the engineered safety features systems:

- boric acid wastage surveillance program
- inspection program for civil engineering structures and components

For all three engineered safety features systems, the applicant cited its chemistry control program to manage loss of material and cracking for components exposed to a treated or borated water environment. The staff considers that this program is common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.2 of this safety evaluation.

For the containment heat removal system and the emergency core cooling system, the applicant cited its preventive maintenance activity assessment to manage loss of material for components exposed to a ventilation air, raw water, air, or borated water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.10 of this safety evaluation.

For the containment heat removal system and the emergency core cooling system, the applicant cited its heat exchanger performance testing activities to manage fouling for components exposed to a raw water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.12, of this safety evaluation.

For the containment isolation system, the applicant cited its treated water system stainless steel inspection to manage loss of material and cracking for components exposed to a treated water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.11 of this safety evaluation.

For the emergency core cooling system, the applicant cited its service water piping corrosion program to manage loss of material for components exposed to a raw water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.13 of this safety evaluation.

For the emergency core cooling system, the applicant cited its galvanic susceptibility inspection to manage loss of material for components exposed to a raw water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.9 of this safety evaluation.

For the emergency core cooling system, the applicant cited its reactor coolant system operational leakage monitoring to manage cracking of components exposed to a treated water environment. The staff considers that this program is common to several systems at the ONS. The staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.7 of this safety evaluation.

For all three engineered safety features systems, the applicant cited its boric acid wastage surveillance program and inspection program for civil engineering structures and components to manage loss of material for components exposed to the reactor and auxiliary building environments. The staff considers that these programs are common to several systems at the ONS. The staff's review of these programs is discussed in the "Common Aging Management Programs," Sections 3.2.1 and 3.2.6 of this safety evaluation.

At the time of the applicant's submittal, the applicant had not fully characterized the aging effects, if any, of stainless steel components of the reactor building spray system exposed periodically to borated water during testing and normally to an air environment. For both the containment heat removal system and the containment isolation system, the applicant plans to perform an inspection, the reactor building spray system inspection, to obtain additional information on this material-environment combination. The staff's evaluation of this inspection is presented next.

Reactor Building Spray System Inspection

The staff focused its evaluation of the applicant's aging management programs, such as the reactor building spray system inspection, on the program elements rather than on details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The LRA indicated that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of the SER. Therefore, these three elements will not be discussed further in this section.

Program Scope
The reactor building spray system inspection characterizes the loss of material (from pitting) and cracking (from stress corrosion cracking) of the stainless steel portions of the system periodically exposed to a borated water environment. This inspection applies to piping and components downstream of the containment isolation valves. This portion of the system is open to the reactor building environment; thus, unmonitored conditions exist in any piping containing borated water which may be trapped downstream of these valves. The applicant stated the most bounding of six susceptible locations will be inspected. If no parameters are known that would distinguish amongst the susceptible locations, the applicant will choose one location as being representative of the remaining locations. The applicant will include at least one stainless steel weld and heat affected zone as part of the inspection scope because this is a more likely location for stress corrosion cracking to occur, as documented in Duke's response to RAI 4.3.9-7. In RAI 4.3.9-6, the staff requested that the applicant provide additional information regarding the inspection scope: (1) confirm that the entire susceptible population for this system consists of these six locations, and (2) provide the parameters that the applicant will evaluate to select the most bounding or representative inspection location. In a May 10, 1999, letter, Duke responded that the six susceptible locations (two per Oconee unit) are the entire susceptible population for the reactor building spray system. Duke further stated that some of the

parameters they may use to select the most bounding inspection location are piping geometry, presence of weld and heat affected zone, accessibility of location, and radiation exposure.

The reactor building spray system inspection does not mention the nitrogen purge and blanketing system, yet the applicant takes credit for this aging management program in Section 3.5.4 of the LRA. The staff requested the applicant discuss how the inspection of the reactor building spray system manages aging effects for the nitrogen purge and blanketing system. Duke responded to the staff's question in a telephone conversation as documented in a phone call summary dated June 2, 1999. The applicant stated that some stainless steel components in the nitrogen purge and blanket system are also exposed to alternate wetting and drying with borated water that could lead to cracking or loss of material. Because the materials and environments are the same for both systems, Duke determined inspections in both systems were not necessary. The applicant also stated that the results of the reactor building spray system inspection bound the components of the nitrogen purge and blanket system. Both systems have stainless steel components alternately wetted and dried with borated water. Where the susceptible components are located in the reactor building spray system, they are exposed to an oxygenated environment in combination with borated water. The nitrogen purge and blanket system components are exposed to nitrogen gas in combination with borated water. Because the oxygenated environment is more corrosive than nitrogen gas, the inspection of the reactor building spray system components is more likely to identify the existence of these applicable aging effects. The staff agrees that the inspection of the reactor building spray system components would bound the inspection of the nitrogen purge and blanket system components. In Confirmatory Item 3.5.3.2-1, the staff requested that the applicant formally submit its response to this program scope question. Duke provided its response in its October 15, 1999, submittal. Therefore, Confirmatory Item 3.5.3.2-1 is closed.

The staff concludes the proposed inspection scope is acceptable because the applicant will inspect the most likely locations for degradation to occur and the inspection locations will be representative of or bound the susceptible population of components.

Preventive/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/Monitored
The applicant plans to use a volumetric nondestructive examination method to perform the inspection. In RAI 4.3.9-8, the staff requested that Duke confirm that the method selected will be qualified for this material type (i.e., stainless steel) and for the degradation modes (i.e., pitting and SCC). In a May 10, 1999, letter, Duke responded that it will use a method that will be qualified for the material type and degradation modes. Duke also stated that the volumetric examination could either be destructive or nondestructive and that a specific inspection method has not been chosen at this time. The staff finds Duke's response reasonable and acceptable.

Detection of Aging Effects
The staff relies on a combination of adequate inspection scope, use of qualified inspection technique(s), and adequate inspection timing to reach the conclusion that aging effects will be detected before there is a loss of intended function. As discussed above, the staff finds the inspection scope and inspection technique adequate. With respect to the inspection timing, the applicant stated this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable, primarily because the staff cannot identify a specific need to perform the inspection any earlier or any later. The environment is not particularly corrosive, and the system design is robust; thus, the staff expects minimal corrosion and finds the use of a one-time inspection adequate. The applicant will implement appropriate corrective actions, including additional inspections, if warranted by the inspection results. Therefore, the staff finds the inspection timing acceptable. Because the applicant has an adequate inspection scope, inspection technique and acceptable inspection timing, the staff concludes the reactor building spray system inspection may be relied upon to detect aging effects before there is a loss of intended function.

Monitoring and Trending
There are no monitoring or trending actions taken as part of this program, and the staff did not identify the need for such actions.

Acceptance Criteria
The applicant stated that any indication of loss of material or cracking in the component will be compared to the ONS component design code of record for acceptability. This is acceptable to the staff because it is consistent with current industry practice.

Operating Experience
The reactor building spray system inspection is a new program; thus, the applicant did not present ONS-specific operating experience. However, industry experience to date supports the attributes of the licensee's program. Therefore, the staff finds that operating experience is satisfactorily incorporated into the development of this new program.

3.5.4 Conclusions

The staff has reviewed the information contained in the containment heat removal system, containment isolation system, and emergency core cooling system sections of Exhibit A, "Technical Information," of the Duke LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the engineered safety features systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended function, in accordance with the CLB, during the period of extended operation.

3.6 Auxiliary Systems

3.6.1 Auxiliary Systems; Air Conditioning, Heating, Cooling and Ventilation Systems; and Post-Accident Hydrogen Control Systems

3.6.1.1 Introduction

The applicant described its aging management review (AMR) of the auxiliary systems; air conditioning, heating, cooling, and ventilation (HVAC) systems; and post-accident hydrogen control systems in Exhibit A, "License Renewal — Technical Information, OLRP-1001," to the license renewal application (LRA). Duke supplemented the LRA with submittals dated September 30, 1999, October 15, 1999, and November 29, 1999. The staff reviewed the application and the supplemental submittals to determine whether the applicant has demonstrated that the effects of aging on these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1.2 Summary of Technical Information in the Application

Auxiliary Systems

Six subsystems constitute the auxiliary systems. The spent fuel pool cooling (SFPC) system purifies and cools the water in the spent fuel pool. This system also interfaces with other plant functions for event mitigation, fire protection, and station blackout. The auxiliary service water system removes decay heat assuming concurrent loss of the main feedwater, emergency feedwater, and decay heat removal systems. The condenser circulating water system serves as the ultimate heat sink during normal operation and for decay heat removal during plant cooldown. The high-pressure service water system supplies water to the fire protection sprinkler systems, hose stations, fire hydrants, and deluge systems. The low-pressure service water system supplies cooling water to various safety-related and non-safety-related systems and components. The component cooling system provides cooling water to various components in the reactor building. In Table 2.5-9 of the LRA, supplemented by Tables 2-1 and 3-1 of Duke's September 30, 1999 submittal, Table 2 of the October 15, 1999 submittal, and Tables 1 and 2 of the November 29, 1999 submittal, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

Air Conditioning and Heating, Cooling, and Ventilation Systems

Three subsystems constitute the HVAC systems. The auxiliary building ventilation system maintains the auxiliary building at a negative pressure with respect to the turbine building and the outside atmosphere so that any potential contamination will be monitored and discharged (if within acceptable limits) through the unit vent. The system also maintains the auxiliary building temperature within certain limits. The control room pressurization and filtration system maintains the control room at a positive pressure using filtered outside air during emergency operation to prevent in-leakage of radioactive effluents or toxic gases from the turbine building, auxiliary building, or outside atmosphere. The system removes smoke from the control room during and after a fire. The system also operates to maintain a suitable environment in the control room and associated areas for equipment operability and personnel habitability. The penetration room ventilation system controls and minimizes the release of radioactive materials from the reactor building to the environment during post-accident conditions. The system collects and processes potential post-accident reactor building penetration leakage to minimize environmental radiation levels. During operation, the penetration room ventilation system maintains a negative pressure in the penetration room with respect to the outside atmosphere and the auxiliary buildings to prevent uncontrolled or unmonitored releases. In Table 2.5-13 of the LRA and Table 3 of the October 15, 1999 submittal, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

Post-Accident Hydrogen Control Systems

Two subsystems constitute the post-accident hydrogen control systems. The containment hydrogen control system maintains the concentration of hydrogen in the reactor building below flammable limits following a loss-of-coolant accident. The post-accident monitoring system draws air samples from various locations inside the reactor building following an accident to determine the hydrogen concentrations. In Table 2.5-17 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

3.6.1.2.1 Effects of Aging

Auxiliary Systems — Aging Effects From Internal Environments

The SFPC system consists of stainless steel components exposed internally to a treated or borated water environment, and the applicant identified loss of material and cracking as applicable aging effects. The auxiliary service water system consists of stainless steel, carbon steel, and cast iron components exposed internally to a raw water or air environment. For those components exposed to a raw water environment, the applicant identified loss of material and fouling as applicable aging effects. For those components exposed to an air environment, the applicant identified loss of material as an applicable aging effect. The condenser circulating water system consists of carbon steel, stainless steel, bronze, admiralty brass, copper, and cast iron components exposed internally to a raw water environment. The applicant identified loss of material as an applicable aging effect for most of the components in this system except for the cast iron pump casing, the recirculating cooling water heat exchangers, and the screens. For these particular components exposed to raw water, the applicant identified no applicable aging effects. The high-pressure service water system consists of stainless steel, carbon steel, cast iron, copper, brass, and bronze components exposed internally to a raw water or air environment. The applicant identified loss of material and fouling as applicable aging effects for all components exposed to raw water except for the cast iron pump casing for which the applicant stated only loss of material was an applicable aging effect (and not fouling) and brass, carbon steel, copper, and stainless steel tubing for which the applicant stated no aging effects were applicable. For those components exposed to an air environment, the applicant identified loss of material as an applicable aging effect. The low-pressure service water system consists of stainless steel, carbon steel, brass, copper, and bronze components exposed internally to either a raw water, treated water, or ventilation air environment. For components exposed to a raw water environment, the applicant identified loss of material and fouling as applicable aging effects, except for the component coolers and reactor building auxiliary coolers. For those components exposed to a treated water environment, the applicant identified loss of material as an applicable aging effect. For those components exposed to a ventilation air environment, the applicant identified loss of material as an applicable aging effect. The component cooling system consists of carbon steel, stainless steel, copper, brass and admiralty brass exposed to either borated water, treated water, air or raw water. For those components exposed to borated or treated water environments, the applicant identified loss of material and/or cracking as applicable aging effects. For those components exposed to an air environment, the applicant identified loss of material as an applicable aging effect. For those components exposed to raw water, the applicant identified loss of material and/or fouling as applicable aging effects. In Table 3.5-4 of the LRA, as supplemented by Tables 2-1 and 3-1 of the September 30, 1999 submittal, Table 2 of the October 15, 1999 submittal, and Tables 1 and 2 of the November 29 1999, submittal, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the auxiliary systems.

HVAC Systems — Aging Effects From Internal Environments

The HVAC system consists of aluminum, galvanized steel, stainless steel, brass, and copper components exposed internally to an air or ventilation air environment. For these materials and environments, the applicant identified no applicable aging effects. In Table 3.5-6 of the LRA and Table 3 of the October 15, 1999 submittal, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the HVAC system.

Post-Accident Hydrogen Control Systems — Aging Effects From Internal Environments

The post-accident hydrogen control system consists of stainless steel components exposed internally to an air environment, and the applicant identified no applicable aging effects. In Table 3.5-8 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the post-accident hydrogen control system.

Auxiliary Systems — Aging Effects From External Environments

The SFPC system consists of stainless steel components exposed externally to the auxiliary building environment except for the spent fuel transfer tube; parts of which are exposed to the reactor building environment, immersed in borated water, or embedded in concrete. The auxiliary service water system consists of stainless steel, carbon steel, and cast iron components exposed externally to the auxiliary and turbine building environments. The condenser circulating water system consists of carbon steel, stainless steel, bronze, admiralty brass, and cast iron components that are exposed externally to the auxiliary and turbine building environments, the intake structure, and the outside yard environment that has portions exposed to an embedded or underground environment. The high-pressure service water system consists of stainless steel, carbon steel, cast iron, copper, brass, and bronze components exposed externally to the auxiliary and turbine building environments and outside yard environments with portions exposed to an underground environment. The low-pressure service water system consists of stainless steel, carbon steel, brass, copper, and bronze components exposed externally to the reactor, auxiliary, and turbine buildings with portions of the system embedded in concrete. The component cooling system consists of brass, carbon steel, copper and stainless steel components exposed externally to the reactor and auxiliary buildings.

For carbon steel, brass, bronze, copper, and galvanized steel components exposed to the reactor building and auxiliary building environments, the applicant identified loss of material as an applicable aging effect. The applicant stated no aging effects were applicable for stainless steel components exposed to the reactor building or auxiliary building environments. For the SFPC system spent fuel transfer tube exposed externally to a borated water environment, the applicant did not explicitly discuss related aging effects and aging management programs. For the components embedded in concrete, regardless of material type, the applicant stated no aging effects were applicable. For components exposed to the auxiliary building, turbine building, and intake structure environments, the applicant identified loss of material as an applicable aging effect for all material types except for stainless steel components. For components exposed to an outside yard environment, the applicant identified loss of material as an applicable aging effect for carbon steel and cast iron components. For carbon steel, cast iron, or stainless steel components exposed to an underground environment, the applicant identified loss of material and cracking as applicable aging effects. In Sections 3.5.2.7.1, 3.5.2.7.2, 3.5.2.7.3, 3.5.2.7.4, and 3.5.2.7.5 of Exhibit A of the LRA and Table 2 of the October 15, 1999 submittal, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for the reactor building, auxiliary building, turbine building, intake structure, outside yard, underground, and embedded concrete environments.

HVAC Systems — Aging Effects From External Environments

The HVAC system consists of aluminum, galvanized steel, stainless steel, brass, and copper components. These components are exposed externally to the auxiliary building environment.

The applicant identified loss of material as an applicable aging effect for all the components within this system, except for the stainless steel components. In Section 3.5.2.7.2 of Exhibit A of the LRA and Table 3 of the October 15, 1999 submittal, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for the auxiliary building environment.

Post-Accident Hydrogen Control Systems — Aging Effects From External Environments

The containment hydrogen control system and the post-accident monitoring system stainless steel components are exposed externally to the reactor and auxiliary building environments. The applicant identified no applicable aging effects for stainless steel components in these environments. In Sections 3.5.2.7.1 and 3.5.2.7.2 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for the reactor and auxiliary building environments.

3.6.1.2.2 Aging Management Programs

To manage aging effects from internal environments, Duke identified the following aging management programs for the auxiliary systems:

- chemistry control program
- service water piping corrosion program
- system performance testing activities
- preventive maintenance activities
- galvanic susceptibility inspection
- cast iron selective leaching inspection
- fire protection program
- treated water systems stainless steel inspections
- reactor coolant system operational leakage monitoring
- heat exchanger performance testing activities

The applicant did not identify any aging effects for the internal environments of the HVAC and post-accident hydrogen control systems; thus, no aging management programs were identified for these systems.

To manage aging effects from external environments, Duke identified the following aging management programs for the auxiliary systems and HVAC systems.

- inspection program for civil engineering structures and components
- boric acid wastage surveillance program
- preventive maintenance activities
- chemistry control program

Aging Management Review

No aging effects for the external surfaces of the post-accident hydrogen control systems were identified; thus, no aging management programs were identified for these systems.

Duke concluded these programs would manage aging effects in such a way that the intended function of the components of the auxiliary systems; air conditioning, heating, cooling and ventilation systems; and post-accident hydrogen control systems would be maintained consistent with the current licensing basis (CLB), under all design loading conditions during the period of extended operation.

3.6.1.3 Staff Evaluation

Duke described its aging management review (AMR) of the auxiliary systems, HVAC systems, and post-accident hydrogen control systems in Exhibit A, "License Renewal — Technical Information, OLRP-1001," to the license renewal application (LRA), as supplemented by the September 30, 1999, October 15, 1999, and November 29,1999 submittals. The staff reviewed the application to determine whether the applicant has demonstrated that the effects of aging on these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.1.3.1 Effects of Aging

Auxiliary Systems — Aging Effects From Internal Environments

For the SFPC system and component cooling system, the applicant identified stainless steel components exposed internally to a borated water environment. As discussed in Section 3.5.2.2 of Exhibit A of the LRA, loss of material from pitting is an applicable aging effect for stainless steel under certain conditions. Excessive levels of halogens, oxygen, and sulfates, combined with stagnant or low-flow conditions can result in pitting of stainless steels in the treated or borated water environments. Cracking from stress corrosion is also an applicable aging effect for these environments. As discussed in Section 3.5.2.2 of Exhibit A of the LRA, excessive levels of halogens and sulfates and elevated temperatures can result in SCC of stainless steel in the borated water environment.

For the auxiliary service water system, the condenser circulating water system, the high pressure service water system, the low-pressure service water system and the component cooling system, the applicant identified stainless steel, carbon steel, cast iron, brass, bronze, and copper components exposed to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, loss of material from general corrosion, pitting, galvanic corrosion, and microbiologically influenced corrosion (MIC) are applicable aging effects for these materials. Loss of material from selective leaching is an applicable aging effect for cast iron components exposed to raw water. Fouling is also an applicable aging effect for raw water systems at the ONS. In Section 3.5.6 and Table 3.5-4 of the LRA, the applicant identified no applicable aging effects for the cast iron pump casing, recirculating cooling water heat exchangers, and screens of the condenser circulating water system and tubing of the high-pressure service water system. The applicant did not identify fouling as an applicable aging effect for valve bodies in the condenser circulating water system, a cast iron pump casing in the high-pressure service water system, and for the component coolers of the low-pressure service water system. In Open Item 3.1.1-1, the staff requested that the applicant present additional information to support its conclusion that there are no applicable aging effects for these particular components exposed to a raw water environment, consistent with the applicant's description of the environment in Section 3.5.2.4. Also, the staff requested that the applicant present additional information to support its conclusion that fouling is not an applicable aging effect for the specific components just discussed. On the basis of the discussion provided in Section 3.1.3.1.4 of this SER, Open Item 3.1.1-1, as it relates to a raw water environment, is closed.

For the auxiliary service water system, high-pressure service water system, and component cooling system, the applicant identified carbon steel, stainless steel, cast iron, and bronze components exposed internally to an air environment. As discussed in Section 3.5.2.1 of Exhibit A of the LRA, loss of material from general corrosion and pitting is an applicable aging effect for carbon steel and cast iron in air environments containing moisture. Loss of material from galvanic corrosion in an air environment can also occur when materials with different electrochemical potentials are in contact in a wetted location. On the basis of the various galvanic couples in these systems, carbon steel and cast iron would be the susceptible materials. There are no applicable aging effects for bronze, copper, or stainless steel components exposed to an air environment.

For the SFPC system, condenser circulating water system, and component cooling system, the applicant identified stainless steel, brass, copper, and carbon steel exposed to a treated water environment. As discussed in Section 3.5.2.5 of Exhibit A of the LRA, loss of material from general corrosion or pitting are applicable aging effects for all these materials, under certain conditions such as elevated oxygen, halogen, or sulfate levels exacerbated by stagnant or low-flow conditions. Loss of material from galvanic corrosion is possible if materials with different electrochemical potentials are in contact in the presence of oxygenated water. Loss of material from erosion-corrosion is an applicable effect for carbon steel components, under certain conditions. SCC is also an applicable aging effect in these environments. Excessive levels of halogens and sulfates and elevated temperatures can result in SCC of stainless steel in the treated water environments. In Section 3.5.6 and Table 3.5-4 of the LRA, the applicant identified no applicable aging effects for the carbon steel and brass recirculating cooling water heat exchangers of the condenser circulating water system exposed to a treated water environment. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that loss of material (from general corrosion, pitting, and/or galvanic corrosion) is not an applicable aging effect for carbon steel and brass in a treated water environment, consistent with the discussion in Section 3.5.2.5 of Exhibit A of the LRA. On the basis of the discussion provided in Section 3.1.3.1.5 of this SER, Open Item 3.1.1-1, as it relates to a treated water environment, is closed.

For the low pressure service water system, the applicant identified copper and stainless steel exposed to a ventilation air environment. As discussed in Section 3.5.2.6 of Exhibit A of the LRA, loss of material from the potential exposure to concentrated boric acid is an applicable aging effect for the copper components. There are no applicable aging effects for stainless steel components exposed to a ventilation air environment.

HVAC Systems — Aging Effects From Internal Environments

The HVAC system consists of carbon steel, aluminum, galvanized steel, stainless steel, brass, and copper components exposed internally to an air or ventilation air environment. The applicant identified no applicable aging effects. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that no aging effects are applicable for the carbon steel components in the penetration room ventilation system exposed to a ventilation air environment, consistent with the discussion in Section 3.5.2 of Exhibit A of the LRA. The staff also requested that the applicant submit additional information to support its conclusion that no aging effects are applicable for the aluminum, galvanized steel, brass, carbon steel, and copper components of the control room pressurization and filtration system exposed to a ventilation air environment, consistent with the discussion in Section 3.5.2.6 of Exhibit A of the LRA. On the basis of the discussion provided in Sections 3.1.3.1.1 and 3.1.3.1.6 of this SER, Open Item 3.1.1-1, as it relates to air and ventilation air environments, is closed.

Post-Accident Hydrogen Control Systems — Aging Effects From Internal Environments

The post-accident hydrogen control system consists of stainless steel components exposed internally to an air environment. There are no applicable aging effects for this material-environment combination.

Aging Effects Resulting From Fatigue

Many of the auxiliary systems and post-accident hydrogen control systems within the scope of license renewal are designed to American National Standards Institute (ANSI) Standards B31.1 and B31.7, Class II and Class III Code requirements. Although these code requirements do not require an explicit fatigue analysis, they do specify allowable stress levels, based on the number of anticipated thermal cycles. Section 5.5 of the license renewal application states that thermal fatigue of these piping system components is considered to be a time-limited aging analysis. The applicant indicates that the results of its engineering analysis determined that the plant operation of these systems will result in equivalent full-temperature cycles less than the 7,000 assumed thermal cycles during the period of extended operation. Therefore, the applicant determined that the existing analysis addressing thermal fatigue of these piping system components within the scope of license renewal is valid for the period of extended operation. In addition, the applicant indicated that thermal fatigue is not an applicable aging effect for the auxiliary systems and post-accident hydrogen control system. The staff concurs with the applicant's assessment and the conclusion that thermal fatigue is not an applicable aging effect for these piping systems. The staff's evaluation of thermal fatigue is discussed in more detail in Section 4.0 of this safety evaluation.

On the basis of the staff's experience, degradation of piping systems (e.g., cracking of welds) may be caused by vibration (mechanical or hydrodynamic) loading. In Request for Additional Information (RAI) 3.5.6-1, the staff requested the applicant to clarify whether this loading effect had been considered in its aging review for the auxiliary systems. The applicant responded by stating that the process used by Duke to identify the applicable aging effects for the structures and components subject to an aging management review, involves the review of NRC generic communications, industry experience, and relevant Oconee experience. The applicant also indicated that cracking as a result of vibration can be generally attributed to deficiencies in design and typically occurs in a short period of operational time when compared to the overall operational life of the plant. On the basis of its assessment, the applicant concluded that cracking as a result of vibrational (mechanical or hydrodynamic) loads was a potential aging effect that was found not to be applicable to the auxiliary systems. The staff concurs with the applicant's assessment and the conclusion that vibration is not an applicable aging effect for these piping systems. The staff considers this assessment to be applicable also to the post-accident hydrogen control system.

In RAI 3.5.8-3, the staff questioned the applicant's identification of applicable aging effects for the heating, ventilation, and air conditioning (HVAC) system. The staff raised a concern that, on the basis of its review experience of other operating plants, cracking of the ductwork occurs as a result of vibration-induced fatigue and loosening of fasteners because of dynamic loading, especially in the vicinity of attached device types (such as fans) exposed to dynamic loads. The applicant responded by stating that cracking of ductwork because of vibrational loads and self-loosening of fasteners because of dynamic loading were determined not to be applicable aging effects for the HVAC system. The applicant stated that components within the scope of license renewal are equipped with isolators to prevent transmission of vibration and dynamic loading to the rest of the system. Therefore, vibration-induced fatigue and self-loosening of fasteners are not applicable aging effects for the HVAC system. The staff's review experience of other operating plants shows that vibration-induced fatigue and self-loosening of fasteners cannot be avoided by the installation of isolators. The staff, in its letter dated April 8, 1999, requested that the applicant address these aging effects or provide additional justification for not considering their applicability. The applicant responded in a letter dated May 10, 1999, that Oconee has had good operating experience with respect to isolators in the auxiliary building ventilation system and control room pressurization and filtration system in preventing the transmission of vibration and dynamic loads to surrounding equipment to preclude ductwork cracking and loosening of fasteners. A review of the Oconee Problem Investigation Process database and Oconee- specific licensee event reports did not identify any instances of cracking of ductwork or loosening of fasteners in these two ventilation systems. In addition, these two systems have been in service for more than 25 years and cracking of ductwork and loosening of fasteners would have revealed themselves as a concern by now. Therefore, the applicant concluded that cracking of ductwork and loosening of fasteners in the auxiliary building ventilation system and control room pressurization and filtration system are not applicable aging effects for these systems. The staff found the additional justification provided by the applicant not acceptable for the following two reasons:

> In general, sub-component parts of isolators are made of elastomers (such as rubber boots, seals, flexible collars, etc.). Elastomers will degrade because of relative motion between vibrating equipment, pressure variations, exposure to temperature changes and oxygen, as so on. Because of the degradation of isolators, vibration and subsequent dynamic loads applied to the ductwork and fasteners cannot be eliminated.
>
> Although no aging effects (cracking of ductwork and loosening of fasteners) were identified after 25 years of operation, one still cannot ensure that there will not be any degradation of the systems within the next 35 years (the remaining design life plus the extended life).

In Open Item 3.6.1.3.1-1, the staff requested that the applicant address these aging effects or provide additional justification for not considering them applicable aging effects.

As a result of a teleconference on October 27, 1999, the staff restated its two concerns related to this open item. The staff stated that the applicant should address (1) cracking of ductwork as a result of vibration-induced fatigue and (2) loosening of fasteners of fan supports (mounts) as a result of dynamic loading caused by fan vibration. The staff also indicated that the licensee could use any of the following four options to resolve the issue of ductwork cracking as a result of vibration-induced fatigue: (1) revisit whether or not the system is within the scope of license renewal, (2) provide an aging management program for the elastomers (which are used in the flexible collars to reduce the vibration transmitted from fans to ductwork) in the system, (3) provide a rigorous analysis to demonstrate that the failure of the elastomers would not result in the loss of the smoke removal function, or (4) consider the elastomers as consumable.

During a meeting with the applicant on December 9, 1999, the staff reiterated its concern regarding the loosening of fasteners of fan supports (mounts) as a result of dynamic loading caused by fan vibration and stated that three options could be used to address the staff's concern: (1) confirm the material (elastomer) for the vibration isolators of the fan mounts is good for 60 years (therefore, it would require no aging management program), (2) provide an aging management program for the mounts, or (3) provide justification that failure of the mounts would not cause failure of the intended function.

In its letter dated December 17, 1999, the licensee provided its response, as summarized below:

Ductwork Cracking Resulting From Vibration-Induced Fatigue

Option 1: The portions of the system needed to perform the smoke removal function are within the scope of license renewal and subject to aging management review.

Option 2: The applicant considers this option somewhat premature in that it presumes applicable aging effects have been identified for the elastomers in the system.

Option 3: The applicant defines the failure of flexible collars, which are made of neoprene-impregnated woven fiberglass as complete severance because of tearing of the collar material. According to the applicant, the system will maintain its smoke removal intended function as long as complete severance does not occur. As a result, the applicant concluded that the need for a more rigorous analysis is not required because aging to the extent required to cause complete severance of flexible collars would not occur.

Option 4: The applicant does not believe the neoprene-impregnated woven fiberglass flexible collars to be consumable.

In addition to its response to these four options, the applicant proposed a fifth option for addressing the staff's concern. The applicant stated that, in this option, on the basis of the recommendation of the Aging Management Guideline for Commercial Nuclear Power Plants, the flexible collar material (neoprene) would maintain its properties for at least 60 years below a temperature of 117°F without loss of its integrity or its ability to perform its function, and it still can be stretched 50 percent beyond its original dimensions. Since the temperature in the auxiliary building, as stated in Updated Final Safety Analysis Report (UFSAR), Section 9.4.3.1, is in the range of 60°F to 104°F, the flexible collars that are made of neoprene will not degrade sufficiently over 60 years to affect their intended function. The applicant also stated that according to the industry literature, industry operating experience, and Oconee-specific experience, the collar material will not degrade as a result of exposure to ozone, utraviolet light, or ionizing radiation. On this basis, the applicant concluded that since the collar material is good for 60 years at 117°F without losing its integrity, the flexible collars will also remain intact to reduce the dynamic forces transmitted to adjacent ductwork resulting from fan vibration. Therefore, the aging effects of cracking because of vibration-induced fatigue should not be a concern for license renewal, and an aging management program is not needed.

Loosening of Fan Support Fasteners as a Result of Vibration

Among the three options suggested by the staff, the applicant chose to confirm that the material for the vibration isolators of the fan mounts is good for 60 years. In its response, the applicant confirmed that the material (elastomer) used in the vibration isolators is neoprene. The applicant also stated that these vibration isolators are exposed to the same environment as the flexible collars used between fans and the adjacent ductwork. On the basis of the justification provided for the flexible collars, the applicant concluded that there are no applicable aging effects for the neoprene in the vibration isolators that could lead to a loss of the system's intended function of smoke removal. Therefore, no aging management program is needed for the neoprene subcomponents of the vibration isolators.

The staff reviewed the applicant's response provided in the submittal of December 17, 1999, and, on the basis of its review experience of other operating plants and industry literature, agreed with the applicant that as long as the neoprene is exposed to temperatures below 117°F, the neoprene will remain sufficiently ductile to function for at least 60 years. As described in Section 9.4.3.1 of the UFSAR, the auxiliary building ventilation system maintains the auxiliary building temperature between 60°F and 104°F. Therefore, the neoprene is expected to be ductile for the 60-year life of the plant.

On the basis discussed above, the staff concludes that since both the flexible collars and fan vibration isolators will remain intact in the auxiliary building environment for 60 years, the dynamic forces transmitted from fans to the supports and adjacent ductwork caused by fan vibration are expected to be reduced. The staff also concludes that cracking of ductwork because of vibration-induced fatigue, and loosening of fasteners of fan supports (mounts) as a result of dynamic loading caused by fan vibration should not be a concern for license renewal. Therefore, Open Item 3.6.1.3.1-1 is closed.

Aging Effects From External Environments

Portions of the auxiliary systems, all of the HVAC systems, and all of the post-accident hydrogen control systems are exposed externally to the reactor building, the auxiliary building, the turbine building, and the intake structure. These are all sheltered environments. The reactor building environment is warm and moist. Temperatures can reach 130 °F during normal unit operation with 100 percent relative humidity. The auxiliary building is heated in the winter and cooled in the summer. The turbine building is heated in the winter and ventilated in the summer. The intake structure is neither heated nor cooled. Loss of material from exposure to concentrated boric acid is an applicable aging effect for brass, bronze, copper, and carbon steel components in the reactor and auxiliary buildings. Loss of material from general corrosion and galvanic corrosion are applicable aging effects for the external surfaces of carbon steel and cast iron components if they come in contact with moisture in any of these environments.

Some of the stainless steel components of the auxiliary system's SFPC system are immersed in borated water. Although the applicant did not explicitly discuss the situation in which borated water is external to the stainless steel component, the aging effects and aging management programs are identical to those for stainless steel components exposed internally to borated water. Thus, loss of material from pitting and cracking from SCC are applicable aging effects for the stainless steel SFPC system components immersed in borated water.

Portions of the auxiliary system's SFPC system, condenser circulating water system, and low-pressure service water system are embedded in concrete. No aging effects are identified for materials embedded in concrete.

Portions of the condenser circulating water system and the high-pressure service water system are exposed externally to the outside yard or underground environments. Loss of material from general corrosion, pitting, galvanic corrosion, or MIC are applicable aging effects for carbon steel, cast iron, and stainless steel materials. Loss of material from selective leaching is an applicable aging effect for cast iron materials. Pitting, MIC, and cracking from SCC is an applicable aging effect for stainless steel materials exposed to an underground environment. The ONS construction practice included the use of protective coatings on the external surfaces of buried components. Continued presence of an intact coating precludes the applicable aging effects on the external surfaces of these materials. The aging effects become an issue if the coatings develop voids or otherwise fail.

Aging Effects — Summary and Conclusions

The applicant supplied references to the ONS-specific, as well as industry-wide experience to support its identification of applicable aging effects for the auxiliary systems, HVAC systems, and post-accident hydrogen control systems. On the basis of this review, the staff concludes the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.6.1.3.2 Aging Management Programs for License Renewal

To manage aging effects from internal environments, Duke identified the following aging management programs for the auxiliary systems:

- chemistry control program
- service water piping corrosion program
- preventive maintenance activities
- galvanic susceptibility inspection
- cast iron selective leaching inspection
- fire protection program
- treated water systems stainless steel inspections
- system performance testing activities
- reactor coolant system operational leakage monitoring
- heat exchanger performance testing activities

The applicant did not identify any aging effects for the internal environments of the HVAC and post-accident hydrogen control systems; thus, no aging management programs were identified for these systems.

Aging Management Review

To manage aging effects from external environments, Duke identified the following aging management programs for the auxiliary systems and HVAC systems.

- inspection program for civil engineering structures and components
- boric acid wastage surveillance program
- preventive maintenance activities
- chemistry control program

The applicant did not identify any aging effects for the external surfaces of the post-accident hydrogen control systems; thus, no aging management programs were identified for these systems.

Some portions of the auxiliary systems within the scope of license renewal are not designed to withstand the effects of a design-basis earthquake. In RAI 3.5.6-2, the staff requested that the applicant clarify which 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) would be subject to an AMR. Additionally, the staff requested that the applicant clarify which aging management programs will address these components and piping segments. The applicant responded by identifying those portions of piping systems that are within the category of "Seismic II over I." The applicant indicated that these piping systems are either designated as ONS Pipe Class D that are designed to withstand the effects of a design-basis earthquake or designated as ONS Pipe Classes G and H for which the associated pipe supports are assigned QA condition 4. This QA condition denotes requirements for seismic structural integrity to prevent adverse interactions with safety-related systems, structures, and components. The applicant stated that the aging management programs listed above apply to all applicable portions of the system, regardless of pipe class. Although this RAI was specific to the auxiliary system, this classification applies to all systems within the scope of license renewal (see summary dated January 31, 2000). Thus, because the scope of the AMR and the following discussion of aging management programs do include all pipe classes, the staff finds Duke's response to this RAI issue reasonable and adequate.

For the auxiliary systems, the applicant cited its chemistry control program to manage loss of material for components exposed (both internally and externally) to a borated water environment or a treated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.2 of this safety evaluation.

For auxiliary systems, the applicant cited its service water piping corrosion program to manage loss of material for components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.13 of this safety evaluation.

For the auxiliary systems, the applicant cited its galvanic susceptibility inspection to manage loss of material for components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.9 of this safety evaluation.

For the auxiliary systems, the applicant cited its cast iron selective leaching inspection to manage loss of material for cast iron components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.8 of this safety evaluation.

For the auxiliary systems, the applicant cited its fire protection program to manage loss of material and fouling for components exposed to air and raw water environments. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.4 of this safety evaluation.

For the auxiliary systems, the applicant cited its treated water systems stainless steel inspection to manage loss of material and cracking of components exposed to a treated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.11 of this safety evaluation.

For the auxiliary systems and HVAC systems, the applicant cited its inspection program for civil engineering structures and components and its boric acid wastage surveillance program to manage loss of material for components exposed to the reactor building, auxiliary building, turbine building, and intake structure environments. The staff considers these programs to be common to several systems at the ONS. Thus, the staff's review of these programs is discussed in the "Common Aging Management Programs," Section 3.2.6 and 3.2.1of this safety evaluation.

For the auxiliary systems, the applicant cited its preventive maintenance activities to manage loss of material for components exposed to a raw water, air, underground, or ventilation air environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.10 of this safety evaluation.

For the auxiliary systems, the applicant cited its heat exchanger performance testing activities to manage fouling for components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.12 of this safety evaluation.

For the auxiliary systems, the applicant cited its reactor coolant system operational leakage monitoring to manage cracking of components exposed to a treated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.7 of this safety evaluation.

For the auxiliary systems, the applicant cited its system performance testing activities to manage fouling for components exposed to a raw water environment. This program is discussed and evaluated below.

<u>System Performance Testing Activities</u>

The staff focused its evaluation of the Duke aging management programs on the program elements rather than on details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of this SER. Thus, these three elements will not be discussed further in this section.

Program Scope
In Section 4.27 of Exhibit A of the LRA, Duke described system performance testing activities that manage aging effects from fouling of various components exposed to raw water in the auxiliary service water system and low-pressure service water system. These components may become fouled from macro-organisms and silting in raw water systems. The staff finds the scope of the program acceptable because these systems are included within the scope of the system performance testing activities.

Preventive/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/Monitored
The applicant monitors system flow and pressure. The staff finds these parameters acceptable because drops in system flow or pressure are excellent indicators of fouling or loss of material.

Detection of Aging Effects
As stated earlier, the staff finds the program scope and parameters monitored to be acceptable. The frequency of performance testing varies by system—ranging from quarterly to every third refueling outage. The auxiliary service water system is visually inspected every 5 years. As documented in a phone call summary dated June 2, 1999, the applicant provided a discussion of operating experience that demonstrates these frequencies can be relied upon to detect aging effects before there is a loss of component intended function. The applicant stated this testing has been performed at Oconee for at least ten years, and some of the testing has been performed since initial operation. Duke has incorporated operating experience into its testing activities, as needed, as part of its corrective action program. The staff concludes the frequency of the testing activity is supported by operating experience to date. The staff concludes the adequate program scope, acceptable monitoring parameters and testing frequency may be relied upon to detect aging effects before there is a loss of component intended function. The staff requested that the applicant formally document its response to this question related to operating experience. This was identified as Confirmatory Item 3.6.1.3.2-1. Duke provided this information in its October 15, 1999 submittal. Therefore, Confirmatory Item 3.6.1.3.2-1 is closed.

Monitoring and Trending
The applicant compares test results to previous test results. The staff finds this acceptable because unfavorable trends will be identified and corrective action implemented before there is a loss of intended function.

Acceptance Criteria
The applicant stated that the acceptance criterion is adequate flow at a sufficiently high pressure to meet system and accident load demands. The staff finds the acceptance criterion adequate because it is based on the primary system functions; that is, to meet system and accident load demands.

Operating Experience
As discussed earlier, the applicant provided a discussion of operating experience relative to system performance testing. The applicant stated this testing has been performed at Oconee for at least ten years, and some of the testing has been performed since initial operation. Duke has incorporated operating experience into its testing activities, as needed, as part of its corrective action program. The applicant has replaced piping in the low pressure service water system based on the results of this testing program. The staff finds the applicant has satisfactorily incorporated operating experience into its program.

3.6.1.4 Conclusions

The staff has reviewed the information for these systems submitted in Exhibit A, "Technical Information," to the Duke LRA, as supplemented by the September 30, 1999, October 15, 1999, and November 29, 1999 submittals. On the basis of this review, the staff concludes that the applicant has demonstrated that aging effects associated with the auxiliary systems, HVAC systems, and post-accident hydrogen control systems will be adequately managed so that there is reasonable assurance that these systems will perform their intended function in accordance with the CLB during the period of extended operation.

3.6.2 Process Auxiliaries, Reactor Coolant Pump Motor Oil Collection System, and Reactor Coolant System Vents, Drains, and Instrument Lines

3.6.2.1 Introduction

Duke described its aging management review (AMR) of the process auxiliaries, reactor coolant pump (RCP) motor oil collection system, and the reactor coolant system (RCS) vents, drains, and instrument lines (VDILs) in Exhibit A, "License Renewal — Technical Information, OLRP-1001," of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that the effects of aging on these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2.2 Summary of Technical Information in the Application

<u>Process Auxiliaries</u>

Process auxiliaries support the RCS during normal operation. Two subsystems constitute the process auxiliaries. The chemical addition system mixes, stores, and injects chemicals into the RCS and auxiliary systems. The system also functions as the central location for sampling various fluids throughout the plant. The coolant storage system collects and stores reactor coolant. In Table 2.5-11 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

<u>RCP Motor Oil Collection System</u>

Each RCP has several components that use or process lubricating oil. Leakage from, or a failure of, these components could lead to uncontrolled leakage of lubricating oil. This situation could result in oil flashing that may lead to fires or equipment inoperability. To avoid this situation, the RCP motor oil collection system provides shields on the oil lift system, oil coolers, and the upper and lower pots to catch oil and carry it into a collection tank. In Table 2.5-19 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

RCS Vents, Drains, and Instrument Lines

The RCS contains VDILs sized, with the exception of the pressurizer relief valve piping, at 2-inch nominal diameter or smaller, and classified as Class B or C piping. The RCS VDILs maintain the RCS pressure boundary and, as such, act as barriers to the release of fission products from the reactor core and vent non-condensable gases and steam following postulated accidents. In Table 2.5-21 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

3.6.2.2.1 Effects of Aging

Process Auxiliaries — Aging Effects From Internal Environments

The chemical addition system consists of stainless steel components. The portion of the system used to draw samples from the secondary side of the steam generators is exposed to a treated water environment. The portion of the system used to draw samples from the primary side of the steam generators and the pressurizer steam and water spaces is exposed to a borated water environment. The coolant storage system consists of stainless steel components exposed to a borated water environment. For the stainless steel components in both systems exposed to either a treated water environment or a borated water environment, the applicant identified loss of material and cracking as applicable aging effects. In Table 3.5-5 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the process auxiliaries.

RCP Motor Oil Collection System — Aging Effects From Internal Environments

The RCP motor oil collection system consists of carbon steel, stainless steel, brass, and copper components exposed to either an air or oil environment. For the carbon steel, stainless steel, brass, and copper components exposed internally to an air environment, the applicant identified no applicable aging effects. For carbon steel, brass, copper, and stainless steel components exposed internally to an oil environment, the applicant identified loss of material as an applicable aging effect. In Table 3.5-9 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the RCP motor oil collection system.

RCS Vents, Drains, and Instrument Lines — Aging Effects From Internal Environments

The RCS VDILs consist of stainless steel components exposed internally to a borated water environment, and the applicant identified loss of material and cracking as applicable aging effects. In Table 3.5-10 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the RCS VDILs.

Aging Management Review

Aging Effects From External Environments

The chemical addition system and the RCS VDILs consist of stainless steel components exposed externally to the reactor building and auxiliary building environments. The coolant storage system consists of stainless steel components exposed externally to the reactor building and auxiliary building environments, except for some stainless steel piping that is embedded in concrete. The RCP motor oil collection system consists of carbon steel, stainless steel, brass, and copper components exposed externally to the reactor building environment. For carbon steel, brass, and copper components exposed to the reactor building and auxiliary building environments, the applicant identified loss of material as an applicable aging effect. The applicant stated that no aging effects were applicable for stainless steel components exposed to the reactor building or auxiliary building environments. For the stainless steel piping embedded in concrete, the applicant stated that no aging effects were applicable. In Sections 3.5.2.7.1, 3.5.2.7.2, and 3.5.2.7.5 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for the reactor building, auxiliary building, and embedded concrete environments.

3.6.2.2.2 Aging Management Programs

To manage aging effects from internal environments, Duke identified the following aging management programs for the process auxiliaries:

- treated water systems stainless steel inspections
- chemistry control program

To manage aging effects from internal environments, Duke identified the following aging management program for the RCP motor oil collection system: RCP motor oil collection system inspection.

To manage aging effects from internal environments, Duke identified the following aging management program for the RCS VDILs: chemistry control program.

To manage aging effects from external environments, Duke identified the following aging management programs for all three systems:

- inspection program for civil engineering structures and components
- boric acid wastage surveillance program

Duke concluded that these programs would manage aging effects in such a way that the intended function of the components of the process auxiliaries; reactor coolant pump motor oil collection system and reactor coolant system vents, drains, and instrument lines, would be maintained consistent with the current licensing basis (CLB), under all design loading conditions during the period of extended operation.

3.6.2.3 Staff Evaluation

Duke described its AMR of the process auxiliaries, RCP motor oil collection system, and the RCS VDILs in Exhibit A, "License Renewal — Technical Information, OLRP-1001," of the LRA. The staff reviewed the LRA to determine whether the applicant had demonstrated that the effects of aging on these systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.2.3.1 Effects of Aging

<u>Process Auxiliaries — Aging Effects From Internal Environments</u>

For the chemical addition system and the coolant storage system, the applicant identified stainless steel components exposed internally to either a treated water environment or a borated water environment. As discussed in Sections 3.5.2.2 and 3.5.2.5 of Exhibit A of the LRA, loss of material from pitting is an applicable aging effect for stainless steel under certain conditions. Excessive levels of halogens, oxygen, and sulfates, combined with stagnant or low flow conditions can result in pitting of stainless steels in the treated or borated water environments. Excessive levels of halogens and sulfates and elevated temperatures can also lead to cracking from stress corrosion cracking (SCC) in stainless steel exposed to treated or borated water environments. Portions of the chemical addition system have been used in the past to add sodium hydroxide (a caustic) to the RCS for pH adjustment. The system remains capable of injecting sodium hydroxide following a loss-of-coolant accident to minimize the zinc-boric acid reaction. Loss of material and cracking are applicable aging effects for the stainless steel components from the caustic environment.

<u>RCP Motor Oil Collection System — Aging Effects From Internal Environments</u>

For the RCP motor oil collection system, the applicant identified carbon steel, stainless steel, brass, and copper components exposed internally to an air environment. As discussed in Section 3.5.2.1 of Exhibit A of the LRA, loss of material from general corrosion and pitting is an applicable aging effect for carbon steel in air environments containing moisture. Loss of material from galvanic corrosion in an air environment can also occur when materials with different electrochemical potentials are in contact in a wetted location. On the basis of the various galvanic couples in these systems, carbon steel would be the susceptible material. There are no applicable aging effects for bronze, copper, or stainless steel components exposed to an air environment.

In Section 3.5.11 and Table 3.5-9 of the LRA, the applicant stated that there were no applicable aging effects for any component in the RCP motor oil collection system, including the carbon steel components. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that there are no applicable aging effects for the carbon steel components exposed to an air environment, consistent with the applicant's description of the environments in Section 3.5.2.1 of Exhibit A of the LRA. On the basis of the discussion provided in Section 3.1.3.1.1 of this SER, Open Item 3.1.1-1, as it relates to an air environment, is closed.

The applicant also identified carbon steel, brass, copper, and stainless steel components exposed to an oil environment. As discussed in Section 3.5.2.3 of Exhibit A of the LRA, loss of material from general corrosion and galvanic corrosion is an applicable aging effect for the carbon steel components if the oil contains water. Loss of material from pitting, crevice corrosion, or microbiologically influenced corrosion is an applicable aging effect for the carbon steel, copper, brass, and stainless steel components if the oil contains oxygenated water, contaminants such as halides or microbiological organisms. Cracking from stress corrosion is an applicable aging effect for the stainless steel components if the oil contains oxygenated water and contaminants such as halides. In Section 3.5.11 and Table 3.5-9 of the LRA, the applicant did not identify cracking as an applicable aging effect for the stainless steel valve bodies and tubing exposed to an oil environment. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that cracking is not an applicable aging effect for the stainless steel components exposed to an oil environment, consistent with the applicant's description of the environment in Section 3.5.2.3 of Exhibit A of the LRA. On the basis of the discussion provided in Section 3.1.3.1.3 of this SER, Open Item 3.1.1-1, as it relates to an oil environment, is closed.

<u>RCS Vents, Drains, and Instrument Lines — Aging Effects from Internal Environments</u>

For the RCS VDILs, the applicant identified stainless steel components exposed internally to a borated water environment. As discussed in Sections 3.5.2.2 and 3.5.2.5 of Exhibit A of the LRA, loss of material from pitting is an applicable aging effect for stainless steel under certain conditions. Excessive levels of halogens, oxygen, and sulfates, combined with stagnant or low flow conditions can result in pitting of stainless steels in the treated or borated water environments. Cracking from stress corrosion is also an applicable aging effect for these environments. Excessive levels of halogens and sulfates and elevated temperatures can result in SCC of stainless steel in the treated or borated water environments.

<u>Aging Effects From Fatigue</u>

Many of the process auxiliaries' components within the scope of license renewal are designed to ANSI Standard B31.1 and B31.7 Class II and Class III Code requirements. Although these codes do not require an explicit fatigue analysis, they do specify allowable stress levels, based on the number of anticipated thermal cycles. In Section 5.5 of Exhibit A of the LRA, the applicant stated that thermal fatigue of these piping system components is considered to be a time-limited aging analysis. The staff's evaluation of thermal fatigue is discussed in more detail in Section 4.0 of this safety evaluation.

On the basis of the staff's experience, degradation of piping systems (e.g., cracking of welds) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In RAI 3.5.7-1, the staff requested that the applicant clarify whether this loading effect has been considered in its aging review for the process auxiliaries. The applicant responded by stating that in the process used by Duke to identify the applicable aging effects for the structures and components subject to an AMR, NRC generic communications, industry experience, and relevant ONS experience were reviewed. The applicant also indicated that cracking from vibration can be generally attributed to deficiencies in design and typically occurs in a short period of time of operation when compared to the overall plant operational life. On the basis of its assessment, the applicant concluded that cracking from vibrational (mechanical or hydrodynamic) loads was a potential aging effect that was determined to be not applicable to the process auxiliaries. The staff concurs with the applicant's assessment and the conclusion that fatigue from vibrational loading is not an applicable aging effect for these piping systems. The staff also considers this assessment to be applicable to the RCP motor oil collection system and the RCS VDILs because the basis for excluding fatigue due to vibrational loading is generic to all three systems.

Aging Effects From External Environments

Nearly all the components in the process auxiliaries, RCP motor oil collection system, and the RCS VDILs are exposed externally to the sheltered reactor building and auxiliary building environments. The reactor building environment is warm and moist. Temperatures can reach 130 °F during normal unit operation with 100 percent relative humidity. Loss of material from exposure to concentrated boric acid is an applicable aging effect for brass, copper, and carbon steel components. Loss of material from general corrosion and galvanic corrosion are applicable aging effects for the external surfaces of carbon steel components if in contact with moisture. In addition to these environments, the coolant storage system has some stainless steel piping that is embedded in concrete. No aging effects are expected for materials embedded in concrete.

Aging Effects — Summary and Conclusions

The applicant supplied references to ONS-specific, as well as industry-wide experience to support its identification of applicable aging effects for the process auxiliaries, RCP motor oil collection system, and RCS VDILs. 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.

3.6.2.3.2 Aging Management Programs for License Renewal

To manage aging effects from internal environments, Duke identified the following aging management programs for the process auxiliaries:

- treated water systems stainless steel inspections
- chemistry control program

To manage aging effects from internal environments, Duke identified the following aging management program for the RCP motor oil collection system: RCP motor oil collection system inspection.

To manage aging effects from internal environments, Duke identified the following aging management program for the RCS VDILs: chemistry control program.

To manage aging effects from external environments, Duke identified the following aging management programs for all three systems:

- inspection program for civil engineering structures and components
- boric acid wastage surveillance program

Some portions of the process auxiliaries within the scope of license renewal are not designed to withstand the effects of a design-basis earthquake. In RAI 3.5.7-2, the staff requested that the applicant clarify which 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) would be subject to an AMR. Additionally, the staff requested that the applicant clarify which aging management programs will address these components and piping segments. The applicant responded by identifying those portions of piping systems that are within the category of "Seismic II over I." The applicant indicated that these piping systems are either designated as ONS Pipe Class D that are designed to withstand the effects of a design-basis earthquake or are designated as ONS Pipe Classes G and H, for which the associated pipe supports are assigned QA condition 4. This QA condition denotes requirements for seismic structural integrity to prevent adverse interactions with safety-related systems, structures, and components. The applicant further stated that all the aging management programs listed above apply to all applicable portions of the system, regardless of pipe class. Although this RAI was specific to the process auxiliaries, this classification applies to all systems within the scope of license renewal (see summary dated January 31, 2000). Because the scope of the AMR and the aging management programs do include all pipe classes, the staff finds Duke's response to this RAI issue reasonable and adequate.

For the process auxiliaries, the applicant cited its treated water systems stainless steel inspection to manage loss of material and cracking of components exposed to a treated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.11 of this safety evaluation.

For the process auxiliaries and the RCS VDILs, the applicant cited its chemistry control program to manage loss of material for components exposed to a borated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs," Section 3.2.2 of this safety evaluation.

For the process auxiliaries, RCP motor oil collection system, and the RCS VDILs, the applicant cited its inspection program for civil engineering structures and components and its boric acid wastage surveillance program to manage loss of material for components exposed to the reactor and auxiliary building environments. The staff considers these programs to be common to several systems at the ONS. Thus, the staff's review of these programs is discussed in the "Common Aging Management Programs," Sections 3.2.6 and 3.2.1 of this safety evaluation.

For the RCP motor oil collection system, the applicant cited its RCP motor oil collection system inspection to manage loss of material for components exposed to an oil environment. The staff's review of this program follows.

<u>RCP Motor Oil Collection System Inspection</u>

The staff's evaluation of the Duke aging management programs focused on the program elements rather than on details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The LRA indicates that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of this SER. Thus, these three elements will not be discussed further in this section.

Program Scope
In Section 4.3.10 of Exhibit A of the LRA, Duke described the RCP motor oil collection system inspection. The RCP motor oil collection system inspection will characterize loss of material from corrosion of the carbon steel, brass, copper, and stainless steel components in the RCP

motor oil collection system that may periodically be exposed to water from contamination of the oil. Because of the density difference between oil and water, the lower portions of the system have the greatest potential to be exposed to water; thus, the applicant plans to visually inspect one RCP oil collection tank to satisfy the inspection requirement for the entire RCP motor oil collection system. Each ONS unit has four RCP oil collection tanks for a total of 12 tanks. In Open Item 3.6.2.3.2-1, the staff requested the applicant identify the basis for concluding that the inspection of 1 tank out of 12 provides for an adequate inspection scope. The staff also requested that the applicant identify the basis for concluding that the inspection of a carbon steel collection tank bounds the other corrosion mechanisms and potentially affected components in the system. In its response dated October 15, 1999, Duke stated that they have observed water in the oil in each of the twelve oil collection tanks. Because the tanks are similar in design, inspection of one tank should be indicative of the conditions in the other tanks. The staff agrees that given similar designs and environments, the aging effects should be similar and, thus, the inspection results from one tank should be applicable to the remaining eleven tanks. On this basis, the staff finds the inspection scope reasonable and adequate. With respect to other corrosion mechanisms and materials, Duke believes that the copper alloys and stainless steel are, in general, more resistant to corrosion than carbon steel. Also, if the applicant identifies any indication of corrosion during the inspection, the applicant will implement its corrective action program and evaluate the need for further inspections of the tanks and of other materials in the tank. The staff agrees that even though the mechanisms can differ (e.g., pitting of stainless steel versus general corrosion of carbon steel), in general, the corrosion resistance of the copper alloys and stainless steel in water should be superior to carbon steel. Thus, the inspection results of the carbon steel portions bound the remaining materials in the system. The staff concludes Duke has adequately addressed staff questions regarding the RCP motor oil collection system inspection. Open Item 3.6.2.3.2-1 is closed.

Preventive/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/Monitored
The applicant will perform a visual inspection of the bottom half of the interior surface of one RCP oil collection tank to determine the presence of corrosion and to characterize the nature of the degradation. If degradation is detected, the applicant plans to conduct a volumetric examination to more fully determine the condition of the tank. The staff finds these techniques acceptable because corrosion and resultant wall loss are detectable by visual and volumetric inspection techniques.

Detection of Aging Effects
The staff relies on a combination of adequate inspection scope, use of qualified inspection technique(s), and adequate inspection timing to reach the conclusion that aging effects will be detected before there is a loss of intended function. As discussed above, the staff finds the inspection scope and inspection technique acceptable. With respect to the inspection timing,

the applicant stated this one-time inspection will be completed by February 6, 2013. The staff finds this inspection schedule acceptable, primarily because the staff cannot identify a specific need to perform the inspection any earlier or any later. The environment is not particularly corrosive, and the system design is robust; thus, the staff expects minimal corrosion and finds the use of a one-time inspection adequate. The inspection will verify that an aging management program is not necessary or corrective actions will be taken consistent with the Duke QA program.

Monitoring and Trending
There are no monitoring or trending actions taken as part of this program, and the staff did not identify the need for such.

Acceptance Criteria
The applicant stated that any indication of loss of material in the component will be compared to the ONS component design code of record for acceptability. This is acceptable to the staff because it is consistent with current practice.

Operating Experience
The RCP motor oil collection system inspection is a new program; thus, the applicant did not present ONS-specific operating experience. However, industry experience to date supports the attributes of the applicant's program. Thus, the staff finds operating experience is satisfactorily incorporated into the development of this new program.

3.6.2.4 Conclusions

The staff has reviewed the information in the process auxiliaries, RCP motor oil collection system, and RCS VDILs sections of Exhibit A, "Technical Information," of the LRA and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with these systems will be adequately managed such that there is reasonable assurance that these systems will perform their intended function in accordance with the CLB during the period of extended operation.

3.6.3 Keowee Hydroelectric Station, Standby Shutdown Facility, Essential Siphon Vacuum System, and Siphon Seal Water System

3.6.3.1 Introduction

Duke described its aging management review (AMR) of the Keowee hydroelectric station (Keowee station) and the standby shutdown facility (SSF) for license renewal in various sections in Exhibit A, "License Renewal — Technical Information, OLRP-1001," of the LRA, as supplemented by its October 15, 1999 submittal. In its September 30, 1999 submittal, Duke described its AMR of the Essential Siphon Vacuum System and the Siphon Seal Water System.

Aging Management Review

The staff reviewed these sections of the LRA and the accompanying submittals, to determine whether the applicant has demonstrated that the effects of aging on the Keowee station and the SSF will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.3.2 Summary of Technical Information in the Application

Keowee Hydroelectric Station

Nine subsystems constitute the Keowee station. The carbon dioxide system protects the Keowee generators from fire by automatically dumping carbon dioxide–filled bottles in the event of a fire. The system also contains interlocks to prevent the Keowee generator from being placed on-line in the event of a fire. The depressing air system forces water from the turbine space to reduce turbine rolling resistance. The generator high-pressure oil system reduces wear of thrust-bearing shoes through lubrication and maintains the pressure boundary for lubrication and cooling of the generator thrust and guide bearings. The governor air system maintains a cover pressure in the governor oil pressure tank. The governor oil system provides the motive force to move the turbine wicket gates following a loss of offsite power. The service water system supplies cooling water from Lake Keowee to various plant equipment and supplies water for fire protection services at Keowee. The turbine generator cooling water system supplies cooling water to the turbine packing box, generator thrust bearing coolers, generator air coolers, and turbine guide bearing oil coolers. This system also serves as backup cooling to other unit loads. The turbine guide bearing oil system provides lubrication and cooling for the turbine guide bearings. The turbine sump pump system moves water from the turbine wheel pit to the Keowee tailrace. In Table 2.5-23 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

Standby Shutdown Facility

The standby shutdown facility (SSF) consists of the following systems, as identified by Duke in its LRA; (1) the air intake and exhaust system supplies combustion air for the SSF diesel engines and removes exhaust gases from the engines. The system also removes particulates from the air supply, reduces noise, increases engine horsepower, and provides for better fuel economy; (2) the diesel generator fuel oil system supplies fuel oil to each diesel engine injector for combustion and fuel injector cooling; (3) the drinking water system distributes potable water; (4) the heating, ventilation, and air conditioning (HVAC) system maintains the SSF environment within a predetermined temperature range to support equipment operability; (5) the reactor coolant makeup system supplies reactor coolant pump seal injection flow to any of the three ONS units in the event that the normal makeup system becomes inoperable and the reactor coolant system temperature is greater than or equal to 250 °F; (6) the sanitary life system collects sanitary wastewater from drains within the SSF; (7) the SSF auxiliary service water system supplies sufficient steam generator inventory to ensure adequate decay heat removal for all three ONS units during a station blackout, in conjunction with the loss of normal and emergency feedwater system flow; and (8) the starting air system supplies compressed air to start the diesel engines. In Table 2.5-25 of the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

In a letter dated October 15, 1999, Duke identified additional components in the diesel jacket water cooling system, SSF diesel generator fuel oil system, SSF diesel generator lube oil system, and the starting air system as being in the scope of license renewal. The diesel jacket water cooling system removes heat from the SSF diesel engines when they are operating and maintains the engines at standby temperatures when the engines are shutdown. The diesel lube oil system provides lubrication and cooling to the SSF diesel engine bearings, gears, and turbocharger bearings while the diesels are operating and provides cooling of the pistons while the diesels are operating.

Essential Siphon Vacuum System and Siphon Seal Water System

The essential siphon vacuum (ESV) system removes trapped air and other gases from the condenser circulating water intake headers. The ESV system operates during normal operation and during any event involving loss of offsite power. The siphon seal water (SSW) system provides operating liquid to the ESV system pumps and also provides sealing and cooling water for the condenser circulating water pump shaft seal and pump motor cooler. In Table 1-1 and Table 1-2 of the September 30, 1999 amendment to the LRA, the applicant identified the components within the scope of license renewal, their passive intended function(s), and their materials of construction.

3.6.3.2.1 Effects of Aging

Keowee Hydroelectric Station — Aging Effects From Internal Environments

The carbon dioxide system consists of carbon and stainless steel components exposed internally to an air environment. The depressing air system consists of carbon steel components exposed internally to an air environment. The generator high-pressure oil system consists of stainless steel, copper, carbon steel, brass, and bronze components exposed internally to either an air or oil environment. The governor air system consists of carbon steel components exposed internally to an air environment. The governor oil system consists of carbon and stainless steel components exposed internally to either an air or oil environment. The service water system consists of stainless steel, carbon steel, cast iron, bronze, ductile iron, brass, and copper components exposed internally to either an air or raw water environment. The turbine generator cooling water system consists of carbon steel, stainless steel, brass, copper, and bronze components exposed internally to a raw water environment. The turbine guide bearing oil system consists of stainless steel, carbon steel, brass, and copper components exposed internally to either an oil, air, or raw water environment. The turbine sump pump system consists of bronze, stainless steel, brass, and carbon steel components exposed internally to a raw water environment.

For most carbon steel and cast iron components in the Keowee station exposed to an air environment, the applicant identified loss of material as an applicable aging effect. The applicant did not identify aging effects for copper, stainless steel, or bronze components exposed to an air environment. For the carbon steel pipe and tank in the governor oil system exposed to an air environment and the carbon steel pipe and tank in the turbine guide bearing oil system exposed to an air environment, the applicant did not identify any applicable aging effects. For all carbon steel, stainless steel, copper, brass, and bronze components exposed to an oil environment in the generator high-pressure oil system and the turbine guide bearing oil system, the applicant did not identify any applicable aging effects. For carbon steel and stainless steel components exposed to an oil environment in the governor oil system, the applicant identified loss of material as an applicable aging effect. For stainless steel, carbon steel, cast iron, bronze, and ductile iron components exposed to raw water in the service water system and the turbine generator cooling water system, the applicant identified loss of material and fouling as applicable aging effects. For brass, copper, and stainless components in the turbine generator cooling water systems, the applicant identified loss of material and fouling as applicable aging effects. For brass, carbon steel, copper, and stainless steel tubing in the service water system, the applicant identified no applicable aging effects. For one cast iron component in the service water system, the applicant identified loss of material, not fouling, as the applicable aging effect. For the stainless steel components of the turbine guide bearing oil system exposed to raw water, the applicant identified loss of material, not fouling, as the applicable aging effect. For the bronze, stainless steel, brass, and carbon steel components in the turbine sump pump system exposed to raw water, the applicant identified loss of material and fouling as applicable aging effects. In Table 3.5-11 of the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the Keowee station.

Standby Shutdown Facility — Aging Effects From Internal Environments

The air intake and exhaust system consists of carbon steel and chromium-molybdenum (chrome-moly) components exposed internally to an air environment. The diesel jacket water cooling system consists of components of brass, carbon steel, stainless steel, and glass exposed internally to treated water, air or raw water. The diesel lube oil system consists of components of brass, carbon steel, stainless steel, and glass exposed internally to oil or treated water. The diesel generator fuel oil system consists of carbon steel, stainless steel, copper, glass, and brass components exposed internally to an oil or air environment. The drinking water system consists of stainless steel components exposed internally to a treated water environment. The HVAC system consists of aluminum, galvanized steel, copper, and stainless steel components exposed to an air environment. The reactor coolant makeup system consists of stainless steel components exposed internally to borated water. The sanitary lift system consists of stainless steel components exposed to an air environment. The SSF auxiliary service water system consists of stainless steel, carbon steel, cast iron, and 90-10 copper-nickel components exposed to either an air or raw water environment. The starting air system consists of components of carbon steel, stainless steel, cast iron and monel exposed internally to dry compressed air.

Except for the stainless steel pipe in the sanitary lift system, the applicant did not identify any aging effects for carbon steel, low-alloy steel, stainless steel, aluminum, galvanized steel, copper, and cast iron exposed to an air environment. For stainless steel, carbon steel, brass, and copper exposed to an oil environment, the applicant identified loss of material and cracking as applicable aging effects. For stainless steel, carbon steel, and brass exposed to a treated water or borated water environment, the applicant identified loss of material and cracking as applicable aging effects. For stainless steel, carbon steel, 90-10 copper-nickel, and brass exposed to a raw water environment, the applicant identified loss of material and fouling as applicable aging effects. For cast iron components exposed to a raw water environment, the applicant stated that no aging effects were applicable. In Table 3.5-12 of the LRA and Table 4-7 of its October 15, 1999 letter, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the SSF.

<u>ESV System and SSW System -- Aging Effects From Internal Environments</u>

The ESV system consists of stainless steel and glass components exposed internally to an air (occasionally wetted by raw water) or raw water environment. The applicant identified loss of material as an applicable aging effect for the stainless steel components exposed to an air (occasionally wetted by raw water) and raw water environment. The SSW system consists entirely of stainless steel components exposed to raw water. The applicant identified loss of material and fouling as applicable aging effects for the stainless steel components. In Table 1-1 and Table 1-2 of the September 30, 1999 amendment to the LRA, the applicant listed the components, materials of construction, internal environment, applicable aging effects, and aging management programs for the ESV and SSW systems.

<u>Keowee Station and the SSF — Aging Effects From External Environments</u>

All subsystems of the Keowee station and the SSF are exposed externally to the Keowee and SSF ambient environment. The applicant considered that the Keowee station and the SSF are sheltered environments. The Keowee station is heated in the winter and ventilated in the summer. The SSF is heated in the winter and cooled in the summer. For carbon steel, chrome-moly, and cast iron components, the applicant identified loss of material as an applicable aging effect. For all other materials exposed to the Keowee station and SSF environments, the applicant did not identify any aging effects. Portions of the SSF auxiliary service water system are exposed to the auxiliary building. Like the Keowee station and the SSF, the auxiliary building is a sheltered environment with climate control. For carbon steel and cast iron components potentially exposed to concentrated boric acid, the applicant identified loss of material as an applicable aging effect. In Section 3.5.2.7.2 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for the Keowee station, the SSF building, and the auxiliary building environments. Some components of the Keowee service water system, the Keowee turbine generator cooling water system, and the SSF diesel generator fuel oil system are exposed to an underground environment. For carbon steel, cast iron, and stainless steel components exposed to an underground environment, the applicant identified loss of material and cracking as applicable aging effects. In Section 3.5.2.7.4 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for an underground environment. Some portions of the Keowee turbine generator cooling water system, the SSF air intake and exhaust system, the SSF HVAC system, and the SSF auxiliary service water system are exposed to an outdoor (yard) environment. For carbon steel, cast iron, and chrome-moly steel, the applicant identified loss of material as an applicable aging effect. In Section 3.5.2.7.3 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for a yard environment. Portions of the turbine sump pump system piping are embedded in concrete. The applicant did not identify any aging effects for materials embedded in concrete. In Section 3.5.2.7.5 of Exhibit A of the LRA, the applicant described the systems, materials of construction, applicable aging effects, and aging management programs for an embedded environment.

ESV System and SSW System -- Aging Effects From External Environments

The ESV system and SSW system components are exposed externally to either a sheltered environment (the ESV building, the turbine building and intake structure), a yard environment (the ESV trenches) and an underground environment. In Section 3.5.2.7.2 of Exhibit A of the LRA, the applicant described aging effects associated with sheltered environments and identified no aging effects for stainless steel components. In Section 3.5.2.7.3 of Exhibit A of the LRA, the applicant described aging effects associated with yard environments and identified no aging effects for stainless steel components. In Section 3.5.2.7.4 of Exhibit A of the LRA, the applicant described aging effects associated with an underground environment and identified loss of material and cracking as applicable aging effects for stainless steel components.

3.6.3.2.2 Aging Management Programs

To manage aging effects from internal environments, Duke identified the following aging management programs for the Keowee station:

- service water piping corrosion program
- galvanic susceptibility inspection
- cast iron selective leaching inspection
- fire protection program
- Keowee air and gas systems inspection
- Keowee oil sampling program

- preventive maintenance activities
- system performance testing activities

To manage aging effects caused by internal environments, Duke identified the following aging management programs for the SSF:

- service water piping corrosion program
- galvanic susceptibility inspection
- chemistry control program
- treated water systems stainless steel inspection
- heat exchanger performance testing activities
- system performance testing activities
- preventive maintenance activities
- jacket water heat exchanger preventive maintenance activity

To manage aging effects caused by internal environments, Duke identified the following aging management programs for the ESV and SSW systems:

- service water piping corrosion program
- system performance testing activities

To manage aging effects caused by external environments, Duke identified the following aging management programs for the Keowee station, the SSF, the ESV, and the SSW systems:

- inspection program for civil engineering structures and components
- preventive maintenance activities
- boric acid wastage surveillance program

Duke concluded that these programs would manage aging effects in such a way that the intended function of the components of the Keowee hydroelectric station, standby shutdown facility, essential siphon vacuum system, and siphon seal water system would be maintained consistent with the current licensing basis (CLB), under all design loading conditions during the period of extended operation.

3.6.3.3 Staff Evaluation

Duke described its aging management review (AMR) of the Keowee hydroelectric station (Keowee station) and the standby shutdown facility (SSF) for license renewal in various sections in Exhibit A, "License Renewal — Technical Information, OLRP-1001," of the LRA, supplemented by its October 15, 1999 letter. Duke described its AMR of the ESV and SSW systems for license renewal in its September 30, 1999 amendment to the LRA. The staff reviewed these sections of the application and submittals to determine whether the applicant has demonstrated that the effects of aging on the Keowee station, the SSF, the ESV, and the

SSW systems will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.6.3.3.1 Effects of Aging

Keowee Hydroelectric Station - Aging Effects From Internal Environments

For the nine subsystems that constitute the Keowee station, the applicant identified carbon steel, stainless steel, copper, bronze, and cast iron components exposed internally to an air environment. As discussed in Section 3.5.2.1 of Exhibit A of the LRA, loss of material caused by general corrosion and pitting is an applicable aging effect for carbon steel and cast iron in air environments containing moisture. Loss of material caused by galvanic corrosion in an air environment can also occur when materials with different electrochemical potentials are in contact in a wetted location. On the basis of the various galvanic couples in these systems, carbon steel and cast iron would be the susceptible materials. There are no applicable aging effects for bronze, copper, or stainless steel components exposed to an air environment. In Section 3.5.13 and Table 3.5-11 of the LRA, the applicant identified no aging effects for the carbon steel pipe and tank in the Keowee governor oil system and the carbon steel pipe and tank in the Keowee turbine guide bearing oil systems. In Open Item 3.1.1-1, the staff requested that the applicant present additional information to support Duke's conclusion that there are no applicable aging effects for these carbon steel components exposed to an air environment, consistent with the applicant's description of the environments in Section 3.5.2.1. On the basis of the discussion provided in Section 3.1.3.1.1 of this SER, Open Item 3.1.1-1, as it relates to an air environment, is closed.

The applicant identified stainless steel, copper, carbon steel, brass, and bronze exposed internally to an oil environment. As discussed in Section 3.5.2.3 of Exhibit A of the LRA, loss of material from general corrosion is an applicable aging effect for carbon steel in an oil environment, at locations containing water. The applicant expected that, because water contamination would accumulate at the lower portions of components such as tank bottoms, only a limited portion of the carbon steel components would be affected. Loss of material may also occur from pitting, crevice corrosion, and microbiologically influenced corrosion (MIC) as well as cracking from stress corrosion cracking (SCC) for brass, bronze, carbon steel, copper, and stainless steel materials in an oil environment at locations containing oxygenated water with contaminants such as halides. In Section 3.5.13 and Table 3.5-11 of the LRA, the applicant identified no aging effects for any components in the Keowee generator high-pressure oil system and the Keowee turbine guide bearing oil system exposed to an oil environment. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that there are no applicable aging effects for these components exposed to an oil environment, consistent with the applicant's description of the environments in Section 3.5.2.3 of Exhibit A of the LRA. On the basis of the discussion provided in Section 3.1.3.1.3 of this SER, Open Item 3.1.1-1, as it relates to an oil environment, is closed.

The applicant identified stainless steel, carbon steel, bronze, ductile iron, cast iron, brass, and copper components exposed to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, loss of material from general corrosion, pitting, galvanic corrosion, and MIC are applicable aging effects for these materials. Loss of material from selective leaching is an applicable aging effect for cast iron components exposed to raw water. Fouling is also an applicable aging effect for raw water systems at the ONS. In Section 3.5.13 and Table 3.5-11 of the LRA, the applicant identified no aging effects for the brass, carbon steel, copper, and stainless steel tubing exposed to raw water in the Keowee service water system. Also, fouling was not identified as an applicable aging effect for the cast iron pump casing in the Keowee service water system and the stainless steel heat exchanger shell, tubes, and tubesheet in the Keowee turbine guide bearing oil system exposed to raw water. In Open Item 3.1.1-1, the staff requested that the applicant present additional information to support its conclusion that there are no applicable aging effects for these components exposed to a raw water environment, consistent with the applicant's description of the environment in Section 3.5.2.4. The staff also requested that the applicant discuss the absence of fouling as an applicable aging effect for the cast iron pump casing in the Keowee service water system and the stainless steel heat exchanger shell, tubes, and tubesheet in the Keowee turbine guide bearing oil system. On the basis of the discussion in Section 3.1.3.1.4 of this SER, Open Item 3.1.1-1, as it relates to a raw water environment, is closed.

Standby Shutdown Facility — Aging Effects From Internal Environments

For the subsystems that constitute the SSF, the applicant identified carbon steel, chrome-moly steel, stainless steel, aluminum, galvanized steel, copper, monel, and cast iron exposed internally to an air environment. As discussed in Section 3.5.2.1 of Exhibit A of the LRA, loss of material from general corrosion and pitting is an applicable aging effect for carbon steel and cast iron in air environments containing moisture. Loss of material from galvanic corrosion in an air environment can also occur when materials with different electrochemical potentials are in contact in a wetted location. On the basis of the various galvanic couples in these systems, carbon steel and cast iron would be the susceptible materials. There are no applicable aging effects for bronze, copper, monel, or stainless steel components exposed to an air environment. In a request for additional information (RAI 3.5.14-1), the staff requested that the applicant describe why aging effects were not identified for the SSF air intake and exhaust system. The applicant responded that the diesel generator serves as an emergency backup and is normally in a standby mode. Required periodic testing of the engines results in approximately 10 hours of operation per year. Because of the infrequent operation of the diesel engines, degradation from exposure to the hot exhaust gases is not considered an applicable aging effect at the ONS. The staff finds this response reasonable and thus acceptable. In Section 3.5.14 and Table 3.5-12 of the LRA, the applicant identified no aging effects for the carbon steel tank in the SSF diesel generator fuel oil system, the cast iron pump casing in the SSF auxiliary service water system, and the carbon steel components in the SSF starting air system. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support Duke's conclusion that there are no applicable aging effects for these components exposed to an air environment, consistent with the applicant's description of the environments in Section 3.5.2.1 of Exhibit A of the LRA. On the basis of the discussion provided in Section 3.1.3.1.1 of this SER, Open Item 3.1.1-1, as it relates to an air environment, is closed.

The applicant identified stainless steel, carbon steel, brass, and copper components exposed to an oil environment. As discussed in Section 3.5.2.3 of Exhibit A of the LRA, loss of material from pitting or crevice corrosion and cracking are applicable aging effects for these materials at locations containing oxygenated water, especially if contaminants such as halides are present. Loss of material from galvanic corrosion is a possible aging effect for carbon steel components if the components are in contact with a material that has a higher electrochemical potential in the presence of water. Loss of material from MIC is an applicable aging effect for these materials if raw water contamination is a possibility for the system. In Table 3.5-12 of the LRA, the applicant identified loss of material and cracking as applicable aging effects for SSF components exposed to an oil environment. Duke also identified components of glass for which there are no aging effects.

The applicant identified stainless steel components exposed to a treated water or borated water environment. As discussed in Sections 3.5.2.2 and 3.5.2.5 of Exhibit A of the LRA, loss of material from pitting or crevice corrosion is an applicable aging effect if the components are exposed to oxygenated water and stagnant or low-flow conditions. Cracking from SCC is another applicable aging effect if the components are exposed to elevated levels of halogens or sulfates. In Table 3.5-12 of the LRA, the applicant identified loss of material and cracking as applicable aging effects for SSF components exposed to a treated or borated water environment.

The applicant identified stainless steel, carbon steel, cast iron, brass, and 90-10 copper-nickel exposed to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, loss of material from general corrosion, pitting, galvanic corrosion, and MIC are applicable aging effects caused primarily by unmonitored chemistry and exacerbated by low or stagnant flow conditions. Selective leaching is an applicable aging effect for cast iron components in a raw water environment. In its October 15, 1999, letter, Duke stated that fouling was an applicable aging effect for carbon steel and brass in heat exchanger components. In Table 3.5-12 of the LRA, the applicant did not identify any aging effects for the cast iron pump casing in the SSF auxiliary service water system. Also, in Section 3.5.14 and Table 3.5-12, the applicant did not identify fouling as an applicable aging effect for the carbon steel and cast iron pump casings in the SSF auxiliary service water system. In Open Item 3.1.1-1, the staff requested that the applicant submit additional information to support its conclusion that there are no applicable aging effects for these components exposed to a raw water environment, consistent with the applicant's description of the environment in Section 3.5.2.4. On the basis of the discussion provided in Section 3.1.3.1.4 of this SER, Open Item 3.1.1-1, as it relates to a raw water environment, is closed.

ESV and SSW Systems - Aging Effects From Internal Environments

For the ESV system, the applicant identified stainless steel and glass exposed internally to an air environment. As discussed in Section 3.5.2.1 of Exhibit A of the LRA and supplemented by the September 30, 1999, amendment, there are no applicable aging effects identified for stainless steel or glass components exposed to an air only environment. For the ESV and SSW systems, the applicant identified stainless steel exposed internally to a raw water environment. As discussed in Section 3.5.2.4 of Exhibit A of the LRA, loss of material and fouling are applicable aging effects for stainless steel exposed to a raw water environment. The applicant stated that fouling is not a concern in the ESV system because the system is primarily an air system, and the amount of raw water intrusion is not sufficient to result in fouling. For the SSW system, both loss of material and fouling are applicable aging effects.

Keowee Station and Standby Shutdown Facility — Aging Effects From Fatigue

Many of the Keowee station and SSF piping system components within the scope of license renewal are designed to ANSI Standard B31.1 and B31.7 Class II and Class III Code requirements. Although these codes do not require an explicit fatigue analysis, they do specify allowable stress levels, based on the number of anticipated thermal cycles. In Section 5.5 of Exhibit A of the LRA, the applicant stated that thermal fatigue of these piping system components is considered to be a time-limited aging analysis. The applicant indicated that its engineering analysis showed that the plant operation of these systems will result in equivalent full-temperature cycles of less than the 7000 assumed thermal cycles during the period of extended operation. Therefore, the applicant determined that the existing analysis addressing thermal fatigue of these piping system components within the scope of license renewal is valid for the period of extended operation. In addition, the applicant indicated that thermal fatigue is not an applicable aging effect for the Keowee station. The staff concurs with the applicant's assessment and the conclusion that thermal fatigue is not an applicable aging effect for these piping systems. The staff's evaluation of thermal fatigue is discussed in more detail in Section 4.0 of this safety evaluation.

On the basis of the staff's experience, degradation of piping systems (e.g., cracking of welds) may potentially be caused by vibration (mechanical or hydrodynamic) loading. In RAI 3.5.13-1, the staff requested that the applicant clarify whether this loading effect has been considered in its aging review for the Keowee station. In its response dated January 25, 1999, the applicant stated that in the process it used to identify the applicable aging effects for the structures and components subject to an AMR, it reviewed NRC generic communications, industry experience, and relevant ONS experience. The applicant also indicated that cracking from vibration can be generally attributed to deficiencies in design and typically occurs in a short period of time of operation when compared to the overall plant operational life. On the basis of its assessment, the applicant concluded that cracking from vibrational (mechanical or hydrodynamic) loads was a potential aging effect that was determined to be not applicable to Keowee station. The staff concurs with the applicant's assessment and the conclusion that vibration is not an applicable aging effect for these piping systems. The staff considers this assessment to be applicable also to the SSF with the following exception. In RAI 3.5.14-3, the staff stated that emergency diesel generator (EDG) starting air systems at several other facilities have experienced degradation from excessive vibration in the piping and starting air valves. In some cases, the degradation rendered the air receivers incapable of delivering starting air to the EDGs at the design pressures. In RAI 3.5.14-4, the staff requested that the applicant discuss the applicability of this industry experience to the starting air system at the ONS's SSF. The staff disagreed with the applicant's generic assessment discussed earlier because the starting air system is used very infrequently and there was no assurance that vibratory stress cycles necessary for causing fatigue failures will occur early in plant life.

In its response the applicant stated that in general, vibration leads to cracking in a relatively short period of time and agreed with the staff that the SSF diesel generator operates infrequently. However, Oconee operating experience has revealed that design deficiencies leading to vibration-induced failures have manifested themselves in the components of the diesel generator skid. Cracks due to vibration were observed in fuel oil piping. The piping design was modified to preclude the effects of the vibration on the fuel oil piping by the installation of flexible hoses. The components of the Starting Air system that are subject to aging management review have always been physically separated from the diesel generator, and, thus, its vibratory loads, by flexible hose. By design, these components are not subjected to the vibratory loads experienced by the other diesel components mounted on the diesel skid.

In addition, Duke stated that the starting air operability is verified every 31 days when the diesel generator is tested. Surveillance requirements for the diesel generator and starting air are dictated by ITS Sections 3.10.1.5 and 3.10.1.6.

Based on the information provided by the applicant as discussed above, the staff concerns related to RAI 3.5.14-4 are considered resolved.

Keowee Station and the SSF - Aging Effects from External Environments

Nearly all the components in the Keowee station and the SSF are exposed externally to the sheltered Keowee station and SSF environments. For these environments, loss of material from general corrosion and galvanic corrosion are applicable aging effects for the external surfaces of carbon steel and cast iron components in contact with moisture. For all other materials exposed to the Keowee station or SSF environments, the staff did not identify any applicable aging effects. Portions of the Keowee station auxiliary service water system are exposed to the auxiliary building. Like the Keowee station and the SSF, the auxiliary building is a sheltered environment with climate control. The aging effects discussed for the Keowee station and the SSF also apply to components in the auxiliary building. In addition, for components in the auxiliary building, loss of material may occur for carbon steel and cast iron components exposed to concentrated boric acid. Some components of the Keowee service water system, the Keowee turbine generator cooling water system, and the SSF diesel fuel oil system are exposed to an underground environment. Corrosion may occur if these components are exposed to soil or groundwater. The ONS construction practice included the use of protective coatings on the external surfaces of buried components. Continued presence of an intact coating precludes the applicable aging effects on the external surfaces of these materials. The aging effects become an issue if the coatings develop voids or otherwise fail. Thus, for carbon steel, cast iron, and stainless steel, loss of material from general corrosion, pitting, galvanic corrosion, MIC, and selective leaching and cracking from SCC are applicable aging effects. Some portions of the Keowee turbine generator cooling water system, the SSF air intake and exhaust system, the SSF HVAC system, and the SSF auxiliary service water system are exposed to an outdoor (yard) environment. For carbon steel components of this system, loss of material from general and galvanic corrosion are applicable aging effects. Portions of the Keowee turbine sump pump system piping are embedded in concrete. There are no applicable aging effects for materials embedded in concrete.

<u>ESV and SSW Systems - Aging Effects From External Environments</u>

The ESV system and SSW system components are fabricated from either glass or stainless steel and exposed externally to either a sheltered environment, a yard environment or an underground environment. The staff did not identify any aging effects for these materials and environments except for stainless steel components exposed to an underground environment. Corrosion may occur if stainless steel is exposed to soil or groundwater. The ONS construction practice includes the use of protective coatings on the external surfaces of buried components. Continued presence of an intact coating precludes the applicable aging effects on the external surfaces of this material. The aging effects become an issue if the coatings develop voids or otherwise fail. Thus, for stainless steel, loss of material due to pitting or MIC and cracking from SCC are applicable aging effects.

<u>Aging Effects — Summary and Conclusions</u>

The staff has reviewed the information provided by the applicant regarding ONS-specific experience, as well as industry-wide experience to support its identification of applicable aging effects for the Keowee station, the SSF, the ESV, and the SSW systems. This included the description of the Keowee station's, SSF's, ESV's, and SSW's internal and external environments and materials of fabrication. 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.

3.6.3.3.2 Aging Management Programs for License Renewal

To manage aging effects from internal environments, Duke identified the following aging management programs for the Keowee station:

- service water piping corrosion program
- galvanic susceptibility inspection
- cast iron selective leaching inspection
- fire protection program
- Keowee air and gas systems inspection
- Keowee oil sampling program
- preventive maintenance activities
- system performance testing activities

To manage aging effects from internal environments, Duke identified the following aging management programs for the SSF:

- service water piping corrosion program
- galvanic susceptibility inspection
- chemistry control program
- treated water systems stainless steel inspection
- heat exchanger performance testing activities
- system performance testing activities
- preventive maintenance activities
- jacket water heat exchanger preventive activity

To manage aging effects from internal environments, Duke identified the following aging management programs for the ESV and SSW systems:

- service water piping corrosion program
- system performance testing activities

To manage aging effects from external environments, Duke identified the following aging management programs for the Keowee station, the SSF, the ESV, and the SSW systems:

- inspection program for civil engineering structures and components
- preventive maintenance activities
- boric acid wastage surveillance program

Some portions of the Keowee station and SSF within the scope of license renewal are not designed to withstand the effects of a design-basis earthquake. In RAIs 3.5.13-2 and 3.5.14-4, the staff requested that the applicant clarify which 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) would be subject to an AMR. Additionally, the staff requested that the applicant clarify which aging management programs will address these components and piping segments. In its response, the applicant identified those portions of piping systems that are within the category of "Seismic II over I." The applicant indicated that these piping systems are either designated as ONS Pipe Class D that are designed to withstand the effects of a design-basis earthquake or designated as ONS Pipe Classes G and H, for which the associated pipe supports are assigned QA condition 4. This QA condition denotes requirements for seismic structural integrity to prevent adverse interactions with safety-related systems, structures, and components. The applicant stated that the aging management programs listed above are for all applicable portions of the system, regardless of pipe class. Although this RAI was specific to the auxiliary system, this classification applies to all systems within the scope of license renewal (see summary dated January 31, 2000) Because the scope of the AMR and the aging management programs does include all pipe classes, the staff finds Duke's response to this RAI issue reasonable and adequate.

For the Keowee station, the SSF, the ESV, and SSW systems, the applicant cited its service water piping corrosion program to manage loss of material for components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.13 of this safety evaluation.

For both the Keowee station and the SSF, the applicant cited its galvanic susceptibility inspection to manage loss of material for components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.9 of this safety evaluation.

For the Keowee station, the applicant cited its cast iron selective leaching inspection to manage loss of material for cast iron components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.8 of this safety evaluation.

For the Keowee station, the applicant cited its fire protection program to manage loss of material and fouling for components exposed to air and raw water environments. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.4 of this safety evaluation.

For the SSF, the applicant cited its chemistry control program to manage loss of material for components exposed to an oil environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the

"Common Aging Management Programs" section, specifically, Section 3.2.2 of this safety evaluation.

For the SSF, the applicant cited its treated water systems stainless steel inspection to manage loss of material and cracking of components exposed to a treated water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.11 of this safety evaluation.

For the SSF, the applicant cited its heat exchanger performance testing activities to manage fouling of components exposed to a raw water environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.12 of this safety evaluation.

For both the Keowee station and the SSF, the applicant cited its inspection program for civil engineering structures and components to manage loss of material for components exposed to the Keowee station, SSF, and auxiliary building environments. The staff considers these programs to be common to several systems at the ONS. Thus, the staff's review of these programs is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.6 of this safety evaluation.

For the Keowee station, the SSF, the ESV, and the SSW systems, the applicant cited its preventive maintenance activities to manage loss of material and fouling for components exposed to an air, raw water, or underground environment. The staff considers this program to be common to several systems at the ONS. Thus, the staff's review of this program is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.10 of this safety evaluation.

For the SSF, the applicant cited its boric acid wastage surveillance program to manage loss of material for components in the auxiliary building potentially exposed to concentrated boric acid. The staff considers these programs to be common to several systems at the ONS. Thus, the staff's review of these programs is discussed in the "Common Aging Management Programs" section, specifically, Section 3.2.1 of this safety evaluation.

The remaining programs, the Keowee air and gas systems inspection, the Keowee oil sampling program, the system performance testing activities, and the jacket water heat exchanger preventive maintenance activity, are discussed in detail below.

The staff's evaluation of the Duke aging management programs focused on the program elements rather than on the details of specific plant procedures. To determine whether these aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The LRA indicates that corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of the SER. Thus, these three elements will not be discussed further in this section.

Keowee Air and Gas Systems Inspection

Program Scope
In Section 4.3.4 of Exhibit A of the LRA, Duke described the Keowee air and gas systems inspection. The inspection is a new program aimed at verifying the integrity of carbon steel components exposed to an air environment and potentially susceptible to a loss of material from general or galvanic corrosion. The Keowee station subsystems in the inspection program are the Keowee carbon dioxide system, the depressing air system, and the governor air system. The scope of the inspections includes representative samples of carbon steel components susceptible to corrosion. Specifically, the program will target the following components: the discharge piping low-elevation point of the carbon dioxide system, a portion of piping between the control valves and the Keowee unit turbine head cover in the depressing air system, and the bottom half of the air receiver tank interior and the piping between the air receiver tank and governor oil pressure tank in the governor air system. These locations contain the components expected to be exposed to the highest rates of general corrosion because these portions in the systems may collect moisture from the internal gas environment. The staff finds the applicant's inspection scope adequate in that bounding locations in all three subsystems have been chosen and should provide adequate information regarding the overall susceptibility of carbon steel to corrosion in an air environment.

Preventive/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/Monitored
The inspection program consists primarily of volumetric examinations (e.g., ultrasonic testing) for the discharge piping low-elevation point of the carbon dioxide system, the piping between the control valves and the Keowee unit turbine head cover in the depressing air system, and the piping between the air receiver tank and governor oil pressure tank in the governor air system. The inspection of the air receiver tanks in the governor air system will rely on visual inspections. The staff finds visual and volumetric inspections adequate because these techniques have been

demonstrated by years of industry experience to be effective in detecting loss of material in carbon steel piping and tanks.

Detection of Aging Effects
The staff relies on a combination of adequate inspection scope, use of qualified inspection technique(s), and adequate inspection timing and frequency to reach the conclusion that aging effects will be detected before there is a loss of intended function. As discussed above, the staff finds the inspection scope and inspection technique satisfactory. With respect to inspection timing and frequency, the applicant did not provide the staff with the inspection schedule other than to state that the Keowee air and gas systems inspection will be completed before the end of the current operating license. 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 LRA, 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 is robust; thus, the staff expects minimal corrosion and finds the use of a one-time inspection adequate. The staff notes that appropriate corrective actions will be taken in accordance with the ONS problem investigation process, which meets the requirements of 10 CFR Part 50, Appendix B for corrective actions. The staff finds that the Keowee air and gas systems inspection has an adequate inspection scope, uses adequate inspection techniques, and adequate inspection schedule and thus 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
There are no monitoring or trending actions taken as part of this program, and the staff did not identify the need for such actions.

Acceptance Criteria
The applicant stated that any indication of loss of material in the component will be compared to the ONS component design code of record for acceptability. This is acceptable to the staff because it is consistent with current industry practice.

Operating Experience
The Keowee air and gas systems inspection is a new program; thus, the applicant did not submit ONS-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.

Keewee Oil Sampling Program

Program Scope
Duke described the Keowee oil sampling program in Section 4.3.5 of Exhibit A of the LRA. The new program verifies the integrity of carbon steel and stainless steel components exposed to an oil environment and potentially susceptible to loss of material from general corrosion, pitting, galvanic corrosion and microbiologically influenced corrosion (MIC). General corrosion, pitting, and galvanic corrosion may occur if the components are exposed to water in the lower portions of the governor oil system. If raw water leaks from the turbine guide bearing oil cooler into the turbine guide bearing oil system, MIC may occur. The program consists of sampling oil reservoirs for the presence of water contamination. Specifically, the program analyzes samples from the governor oil system sump and turbine guide bearing oil system reservoirs. The staff finds the scope of the program acceptable in that both systems identified as requiring aging management are within the scope of this program.

Preventive/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/Monitored
The applicant analyzes oil samples taken every six months for water contamination. The staff finds the level of water contamination to be an appropriate parameter because water would be the primary cause of any corrosion that occurs in the systems.

Detection of Aging Effects
As stated earlier, the staff found the program scope and parameters monitored to be acceptable. The applicant analyzes the oil samples following industry guidance; specifically, ASTM D95-83, "Water in Petroleum and Bitumens." This standard provides a widely used and accepted method of determining the amount of water in a sample of oil, but it does not provide recommendations for sampling frequency. The applicant plans to take oil samples every six months for analyses. The applicant also stated that the program will be implemented by February 6, 2013. The applicant did not provide the basis for the six month sampling interval, nor did the applicant justify delaying the implementation of the program until possibly February 6, 2013. The relatively frequent oil sampling of every six months indicates to the staff that there is a need to perform this testing on a fairly aggressive schedule. In Open Item 3.6.3.3.2-1, the staff requested the applicant provide the basis for the 6-month sampling interval, as well as the basis for implementing the Keowee oil sampling program by the 41st year of operation. In its response dated October 15, 1999, Duke clarified that the Keowee oil sampling program has been implemented for a number of years by Duke, but that the program has not been under control by Oconee. Thus, the program has not had the rigorous control and documentation normally associated with nuclear programs. Duke plans to bring the program under the control of the nuclear department at Oconee such that procedural controls and formal documentation will be in place and consistent with other aging management programs. The

applicant considers the Keowee oil sampling program to be a new program even though it has been performed for several years at Keowee. The frequency of sampling for this program has historically been every six months and operating experience has shown this frequency to be acceptable. Duke will continue to sample at this frequency when it formally places the program under Oconee control. With respect to the schedule for implementing the Keowee oil sampling program, Duke stated that the program will be formally implemented at Oconee concurrent with the UFSAR update required by 10 CFR 50.71(e), after the Oconee renewed operating license is issued by the NRC. The staff finds the applicant's basis for sampling frequency and program implementation scheduling reasonable and, therefore, acceptable. On this basis, Open Item 3.6.3.3.2-1 is closed.

Monitoring and Trending
The applicant trends the oil sample analysis results. The staff finds this acceptable in that adverse trends in level of water contamination will be identified and corrected before there is a loss of intended function.

Acceptance Criteria
The applicant implements corrective actions if the oil samples contain greater than 0.1 percent water by volume. As documented in a phone call summary dated June 2, 1999, the applicant provided to the staff the basis for this acceptance criteria. Duke stated that its operating experience at its hydro facilities established a 0.1 percent water by volume as the corrective action limit. The applicant also stated that EPRI document NP-4916, "Lubrication Guide," Revision 2 (which documents the latest industry guidance in this area) recommends a limit of 0.2 percent water by volume. Duke continues to use the more conservative limit of 0.1 percent water by volume and credits it as the corrective action limit. The staff concludes the applicant provided a reasonable and conservative basis for its acceptance criteria for this program. In view of the importance of Keowee as an emergency power source, the staff requested the applicant formally document its response to this question. This was identified as Confirmatory Item 3.6.3.3.2-1. Duke provided this information in its October 15, 1999, submittal. Therefore, Confirmatory Item 3.6.3.3.2-1 is closed.

Operating Experience
Although not formally part of the nuclear programs at ONS, Duke has implemented the Keowee oil sampling program for a number years. The staff finds that the applicant's operating experience to date demonstrates this program has been effective in preventing corrosion due to water intrusion in the governor oil and turbine guide bearing oil system.

<u>System Performance Testing Activities</u>

Program Scope
In Section 4.27 of Exhibit A of the LRA, Duke described system performance testing activities that manage aging effects caused by fouling of various components exposed to raw water in the Keowee station's turbine generator cooling water and turbine sump pump systems as well as

the SSF's auxiliary service water system and the SSW system. These components may become fouled from macro-organisms and silting in raw water systems. The applicant also credited these activities with managing loss of material for the SSF auxiliary service water system stainless steel air ejectors and orifices. The staff finds the scope of the program acceptable because these systems are included in the system performance testing activities.

Preventive/Mitigative Actions
There are no preventive or mitigative actions taken as part of this program, and the staff did not identify the need for any.

Parameters Inspected/Monitored
The applicant monitors system flow and pressure. The staff finds these parameters acceptable because drops in system flow or pressure are excellent indicators of fouling or loss of material.

Detection of Aging Effects
As stated earlier, the staff found the program scope and parameters monitored to be acceptable. The applicant stated that the frequency of performance testing varies by system, ranging from quarterly to every third refueling outage. The turbine generator cooling water system is tested every time the Keowee station operates, which is about 10 percent of the time. The auxiliary service water system is visually inspected every 5 years. As documented in a phone call summary dated June 2, 1999, the applicant provided a discussion of operating experience that demonstrates these frequencies can be relied upon to detect aging effects before there is a loss of component intended function. The applicant stated this testing has been performed at Oconee for at least ten years, and some of the testing has been performed since initial operation. Duke has incorporated operating experience into its testing activities, as needed, as part of its corrective action program. The staff concludes the frequency of the testing activity is supported by operating experience to date. The staff concludes the adequate program scope, acceptable monitoring parameters and testing frequency may be relied upon to detect aging effects before there is a loss of component intended function.

Monitoring and Trending
The applicant compares test results to previous test results. The staff finds this acceptable because adverse trends will be identified and corrective action implemented before there is a loss of intended function.

Acceptance Criterion
The applicant stated that the acceptance criterion is adequate flow at a sufficiently high-pressure to meet system and accident load demands. The staff finds the acceptance criterion adequate because it is based on primary system functions to meet system and accident load demands.

Operating Experience
As discussed earlier, the applicant provided a discussion of operating experience relative to system performance testing. The applicant stated that most of this testing has been performed

at Oconee for at least ten years, and some of the testing has been performed since initial operation. Duke has incorporated operating experience into its testing activities, as needed, as part of its corrective action program. The applicant has replaced piping in the low pressure service water system based on the results of this testing program. The staff finds the applicant has satisfactorily incorporated operating experience into its program.

Jacket Water Heat Exchanger Preventive Maintenance Activity

In response to Open Item 2.2.3.4.8.2.1-1, Duke proposed this activity in its October 15, 1999 letter, to manage loss of material of admiralty brass tubes. It is an existing activity that will be continued into the period of extended operation.

Program Scope
The portion of the brass tubes exposed to raw water in the jacket water heat exchangers are addressed by this activity. The staff finds the scope acceptable because it addresses the components in the environment susceptible to loss of material.

Preventive/Mitigative Actions
There are no preventive or mitigative actions taken as part of this program and the staff did not identify the need for any.

Parameters Inspected/Monitored
Parameters monitored are system operating temperatures, pressures, and expansion tank levels. The staff finds the parameters acceptable because changes in these parameters will indicate loss of material.

Detection of Aging Effects
The monitoring is performed quarterly. The staff finds this program element acceptable because it should indicate degradation before a loss of intended function of the components.

Acceptance Criteria
System operating temperatures, pressures, and expansion tank levels of the jacket water cooling system are to be within the acceptable operating ranges. The staff finds this acceptable because these parameters indicate the system is performing its intended function.

Operating Experience
This program is an existing one for Duke; a program consistent with those commonly used in the industry.

3.6.3.4 Conclusions

The staff has reviewed the information for the Keowee station, the SSF, the ESV, and the SSW systems included in Exhibit A, "Technical Information," to the Duke LRA, additional information submitted by the applicant in response to the staff RAIs, and the September 30, 1999 submittal amending the LRA. On the basis of this review, the staff concludes that the applicant has demonstrated that aging effects associated with the Keowee station, the SSF, the ESV, and the SSW systems will be adequately managed such that there is reasonable assurance that these systems will perform their intended function, in accordance with the CLB during the period of extended operation.

3.6.4 Chilled Water System (WC)

3.6.4.1 Introduction

Originally, Duke did not include the WC in the scope of license renewal. However, in response to Open Item 2.2.3.4.3.2.1-1 (letter dated October 15, 1999), Duke committed to include the WC in the scope and described its aging management review. The staff reviewed Duke's letter to determine whether Duke had demonstrated that the effects of aging on the WC will be adequately managed during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.4.2 Summary of Technical Information

The WC provides chilled water to various cooling coils in the control room pressurization and filtration systems to provide temperature control for the control areas. The materials of construction of this system are brass, carbon steel, cast iron, copper, galvanized steel, glass, and stainless steel. The tubes of the heat exchanger in the refrigeration unit are constructed of copper. The WC components that are subject to aging management review are listed in Table 1 of Duke's October 15, 1999, letter. The environments are air, raw water, treated water, and refrigerant.

3.6.4.2.1 Effects of Aging

Duke evaluated the applicability of aging effects for components subject to AMR. The aging effects turned out to be loss of material, fouling, and cracking.

3.6.4.2.2 Aging Management Programs

Duke will use the following programs and activities to manage the aging effects of the WC for the period of extended operation:

- boric acid wastage surveillance program
- cast iron selective leaching inspection
- chemistry control program
- WC refrigeration unit preventive maintenance activity (new)
- galvanic susceptibility inspection

- inspection program for civil engineering structures and components
- service water piping corrosion program (as modified)
- treated water stainless steel inspection

3.6.4.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information provided in the LRA and the October 15, 1999, letter. The purpose of the review was to ascertain whether the applicant had adequately demonstrated that the effects of aging will be adequately managed so that the intended function of the systems will be maintained consistent with the CLB for the period of extended operation. The staff evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of the SER.

3.6.4.3.1 Effects of aging

Duke stated that the applicable aging effect for carbon steel components in an air environment is loss of material. The staff review of the aging effects of materials exposed to air is provided in Section 3.1.3.1.1 of the SER (June 1999). Based on its review, the staff concludes that the LRA and the October 15, 1999, letter include aging effects that are consistent with published literature and industry experience and are acceptable to the staff.

Duke stated that the applicable aging effects for the components constructed of carbon steel exposed to raw water are loss of material and fouling. The staff review of the aging effects of materials exposed to raw water is provided in Section 3.1.3.1.4 of the SER (June 1999). Based on its review, the staff concludes that the LRA and the October 15, 1999, letter include aging effects that are consistent with published literature and industry experience and are acceptable to the staff.

Duke stated that the applicable aging effect for the components constructed of brass, carbon steel, cast iron, copper and galvanized steel exposed to treated water is loss of material and that the applicable aging effects for stainless steel components exposed to treated water are loss of material and cracking. Duke did not identify any applicable aging effects for glass in treated water. The staff review of the aging effects of materials exposed to treated water is provided in Section 3.1.3.1.5 of the SER (June 1999). Based on its review, the staff concludes that the LRA and the October 15, 1999, letter include aging effects that are consistent with published literature and industry experience and are acceptable to the staff.

The review to identify applicable aging effects for glass and for materials exposed to refrigerant have not been previously reviewed by the staff. Duke has performed a review to identify the aging effects for glass and refrigerant using the methodology described in Section 3.5.2 of Exhibit A of the LRA. Based on this review, Duke has determined that there are no applicable aging effects for glass or for any material exposed to refrigerant. The staff finds this determination consistent with published literature and industry experience and is acceptable to the staff.

The exterior surfaces of the WC are exposed to a sheltered environment. Duke stated that the applicable aging effect for components constructed of brass, carbon steel, cast iron, copper, or galvanized steel exposed to a sheltered environment is loss of material, and that no applicable aging effects exist for the stainless steel components or glass exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the SER. Based on its review, the staff concludes that the LRA and the October 15, 1999, letter include aging effects that are consistent with published literature and industry experience and are acceptable to the staff.

3.6.4.3.2 Aging Management Programs

Duke stated that loss of material from boric acid wastage is an aging effect for components constructed of brass, carbon steel, cast iron, copper, and galvanized steel located in the auxiliary building. Duke will manage this aging effect by the boric acid wastage surveillance program, which is described in Section 4.5 of Exhibit A of the LRA. The staff reviewed the boric acid wastage surveillance program in Section 3.2.1 of the SER (June 1999) and concluded that the applicant has demonstrated that this program would adequately manage boric acid wastage.

For loss of material of cast iron components, Duke will apply the cast iron selective leaching inspection described in Section 4.3.2 of Exhibit A of the LRA to manage the applicable aging effects for all components including those added to the scope of license renewal. This is a scope addition to this activity. The staff reviewed the cast iron selective leaching inspection in Section 3.2.8 of the SER, and concluded that the applicant has demonstrated that this program would adequately manage the selective leaching of cast iron components.

For loss of material in the components constructed of brass, carbon steel or copper exposed to treated water and the internal portion of the carbon steel tank exposed to air, Duke will use the chemistry control program described in Section 4.6 of Exhibit A of the LRA to manage the applicable aging effects for all components including those added to the scope of license renewal. The staff review of the chemistry control program is provided in Section 3.2.2 of the SER (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with components exposed to primary, secondary and cooling water chemistry.

A purpose of WC refrigeration unit preventive maintenance is to manage fouling of the condensing heat exchanger exposed to raw water and loss of material of the tubes exposed to raw water. The scope of the program is the portion exposed to raw water in the condensing heat exchangers of the refrigeration unit. For these portions, system parameters of the entire refrigeration unit are monitored during operation to provide evidence of fouling and loss of material. Parameters monitored include inlet and outlet temperatures along with refrigerant pressures. No code or standard exists to guide or govern this activity. This activity is performed quarterly. The acceptance criteria are that inlet and outlet operating temperatures and refrigerant pressures are within the acceptable operating ranges. Specific corrective actions are implemented in accordance with the problem investigation process. The problem investigation process applies to all structures and components within the scope of the WC refrigeration unit preventive maintenance activity. The WC refrigeration unit preventive maintenance activity is an existing activity that will be continued into the extended period of operation. The staff finds this program acceptable because it is consistent with industry practice and should provide reasonable assurance that the aging effects will be managed before the intended function is lost.

Duke will manage the loss of material of portions of the WC exposed to raw water by the galvanic susceptibility inspection. This activity is described in Section 4.3.3 of Exhibit A of the LRA. The staff review of the galvanic susceptibility inspection is provided in Section 3.2.9 of the SER. Based on its review, the staff concluded that the applicant has demonstrated that the galvanic susceptibility inspection will adequately manage the aging effects associated with loss of material due to corrosion for systems that have components exposed to a raw water environment for the period of extended operation.

Duke will apply the inspection program for civil engineering structures and components to manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the auxiliary building and turbine building. This program is described in Section 4.19 of Exhibit A of the LRA. The staff review of the inspection program for civil engineering structures and components is provided in Section 3.2.6 of the SER. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

Duke will use the service water piping corrosion program to manage the loss of material due to general corrosion, pitting corrosion, and microbiologically influenced corrosion of the carbon steel components exposed to a raw water environment. This program is described in Section 4.25 of Exhibit A of the LRA, and subsequently modified by the collective Duke response to the SER Open Items 3.2.13-1, 3.2.13-2, 3.2.13-3 and 3.2.13-4. The staff review of the service water piping corrosion program is provided in Section 3.2.13 of the SER. Based on its review, the staff concludes that the applicant has demonstrated that the service water piping corrosion program will adequately manage the aging effects associated with a loss of material from corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

Duke will manage cracking in the stainless steel components exposed to treated water by the treated water systems stainless steel inspection as described in Section 4.3.13 of Exhibit A of the LRA. The staff review of the treated water systems stainless steel inspection is provided in

Section 3.2.11 of the SER (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the treated water systems stainless steel inspection will adequately manage the aging effects associated with cracking of components exposed to a treated water environment for the period of extended operation.

3.6.4.4 Conclusions

The staff has reviewed the information in the October 15, 1999, letter, and on the basis of this review concludes that Duke has demonstrated that aging effects affecting the WC will be adequately managed so that there is reasonable assurance that it will perform its intended function in accordance with the CLB during the period of extended operation.

3.7 Steam and Power Conversion Systems

3.7.1 Introduction

Duke described its aging management review (AMR) of the steam and power conversion systems (SPCSs) for license renewal in the following two sections of its license renewal application (LRA): Section 3.5.9, "Steam and Power Conversion Systems," and Section 4.21, "Piping Erosion/Corrosion Program," of Exhibit A of the LRA. The staff reviewed these sections of the application 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). In the course of its review, the staff sent the applicant requests for additional information (RAIs) concerning these systems. Duke responded by letter dated December 14, 1998.

3.7.2 Summary of Technical Information in the Application

Section 3.5.9 of Exhibit A in the LRA describes four SPCSs: main steam system (MSS), condensate system (CS), emergency feedwater system (EFS), and feedwater system (FS).

The MSS transports steam from the steam generators to the main turbine, to the main feedwater pump turbine, to the emergency feedwater turbine during emergency operation, and to a variety of other components during normal operation. With the exception of orifices, all the components in the MSS are constructed from carbon steel. The orifices are constructed from stainless steel. All the components are exposed to the external environments of the auxiliary, turbine, and reactor buildings and to an internal environment of treated water, which could be heated to superheated, dry, saturated, or partially condensed steam.

Aging Management Review

The CS delivers condensate from condenser hotwells to the suction of the main feedwater pumps, purifies the condensate, removes noncondensable gases, and heats the condensate. It also supplies water to the emergency feedwater pumps during emergency operation. The CS components are constructed from carbon steel, stainless steel, cast iron, brass, and copper. They are exposed to the internal environment of treated water, with the exception of the channel heads and some tubes and tubesheets in the condensate cooler heat exchangers, which are exposed to raw water. The external environment for all the components is air in the turbine building.

The EFS supplies water to the steam generators in the event of loss of both main feedwater pumps. The EFS components are constructed from carbon steel, low-alloy steel, and stainless steel. They are exposed to an internal environment of treated water and to an external environment of air in the turbine and reactor buildings.

The FS receives its water from the CS. It increases feedwater pressure and temperature, and delivers the feedwater to the steam generators. The components in the FS are constructed from carbon steel and stainless steel. They are exposed to the internal environment of treated water and to an external environment of air in the auxiliary, reactor, and turbine buildings.

3.7.2.1 Effects of Aging

The applicant evaluated the applicability of aging effects for components subject to the AMR. It determined that for the materials of construction of the components in the SPCSs, the aging effects from the following plausible mechanisms should be managed for license renewal: loss of material from general corrosion, galvanic corrosion, pitting, and erosion/corrosion in components made from carbon steel, low-alloy steel, brass, and copper; stress-corrosion cracking and pitting of stainless steel components; and selective leaching in the cast iron components.

3.7.2.2 Aging Management Programs

The applicant has identified a number of aging management programs for controlling the effects of aging in the SPCSs. The programs were developed from industrywide data, industry-developed methodologies, Nuclear Regulatory Commission (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 intended function of the components in the SPCSs will be maintained during the period of extended operation, consistent with the current licensing basis (CLB), under all design conditions. The following existing aging management programs were identified by the applicant:

- Chemistry control program
- Piping erosion/corrosion program
- Service water piping corrosion program
- Cast iron selective leaching program
- Galvanic susceptibility inspection program
- Preventive maintenance activity assessment

Erosion/corrosion is the most significant aging mechanism in terms of damage to components in the SPCSs. The piping erosion/corrosion program is considered, therefore, one of the most important programs for managing aging effects. The program applies to the MSS and FS because some of the carbon steel components in the main steam and feedwater systems, included in the AMR, have been identified as being susceptible to erosion/corrosion damage. Section 4.21 of Exhibit A in the LRA contains a description of the existing erosion/corrosion program, which the applicant intends to use during the period of extended operation. This program systematically inspects erosion/corrosion-susceptible components for signs of degradation and, if such signs are detected, directs appropriate corrective actions.

The applicant's erosion/corrosion program consists of predicting which components are susceptible to erosion/corrosion. For that purpose the applicant initially used the predictive method recommended by Electric Power Research Institute (EPRI) report NP-3944. More recently, the applicant has used the EPRI-developed computer code CHECWORKS, although the previous predictive method is still in use for predicting erosion/corrosion in some components. The components found to be affected by erosion/corrosion are inspected either by ultrasonic testing or by radiography. The findings of these inspections are then evaluated against the acceptance criteria, which specify an allowable limit for the minimum thickness of the component. If the code predicts that at the next outage this limit will be exceeded, the component is repaired or replaced. The frequency of inspections depends on location, previous inspection results, calculated material loss, and operating conditions. The applicant has had a formalized erosion/corrosion program since the early 1980s.

3.7.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information included in Sections 3.5.9 and 4.21 of Exhibit A of the LRA. The purpose of the review was to ascertain that the applicant has sufficiently demonstrated that effects of aging will be adequately managed so that the intended function of the systems will be maintained consistent with the CLB for the period of extended operation. The staff evaluation of the applicant's identification of structures and components subject to an AMR is discussed separately in Section 2.2 of this safety evaluation report (SER).

3.7.3.1 Effects of Aging

The components in the SPCSs are constructed from carbon, low-alloy, and stainless steel; cast iron; copper; and brass. They are exposed to an external environment of air in the auxiliary, turbine, and reactor buildings, which by itself will not cause any significant aging effects. Internally, the components in the SPCSs are exposed to a treated water/steam environment, with the exception of the secondary side of the main condensers and condensate coolers in the CS, which remain in contact with raw water. In the systems carrying raw water, the aging effects are loss of material from general corrosion of carbon steel components and pitting and stress-corrosion cracking of stainless steel components. The following material degradation effects were identified in the systems carrying treated water and steam: loss of material from general corrosion and pitting of carbon steel, low-alloy steel, cast iron, brass, and copper; loss of material from erosion/corrosion of carbon steel components; galvanic corrosion of coupled materials having different electrochemical potentials; selective leaching of cast iron and loss of material from pitting; and stress-corrosion cracking of stainless steel components.

The only potential aging effect not related to corrosion is damage from mechanical vibration of piping systems and supports. However, in response to the staff's inquiry (RAI 3.5.9-4), Duke has stated that this damage could only be attributed to poor design and typically will occur over a relatively short period of time before being detected and corrected to prevent recurrence. The staff concurs with the applicant's assessment and conclusion that mechanical vibration is not an applicable aging effect for the piping systems in the SPCSs.

The applicant supplied references to Oconee Nuclear Station (ONS)-specific as well as industrywide experience to supports its identification of applicable aging effects for steam and water conversion systems. The staff concludes that, on the basis of the description of the internal and external environments and material of fabrication for these systems, the applicant has included aging effects that are consistent with published literature and industry experience and, thus, are acceptable to the staff.

3.7.3.2 Aging Management Program for License Renewal

The staff evaluated the applicant's aging management programs in order to determine if they contain the essential elements needed to provide adequate aging management of the components in the SPCSs so that the components will perform their intended functions in accordance with the CLB during the period of extended operation. In its LRA the applicant stated that the activities for license renewal will be conducted in accordance with programs meeting the requirements of 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. Presented below are results of the staff's evaluation of the applicant's programs for monitoring and controlling aging effects on the SPCSs.

The applicant is using several programs to manage aging effects in various systems of the SPCSs. The staff has evaluated the following programs in the sections of the SER listed below:

- Section 3.2.2, "Chemistry Control Program"
- Section 3.2.8, "Cast Iron Selective Leaching Inspection"
- Section 3.2.9, "Galvanic Susceptibility Inspection"
- Section 3.2.10, "Preventive Maintenance Activity Assessment"
- Section 3.2.13, "Service Water Piping Corrosion Program"

Piping Erosion/Corrosion Program

The staff evaluation of the applicant's aging management programs focused on the program elements rather than details of specific plant procedures. The staff evaluated how effectively the piping erosion/corrosion program incorporates the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative control, and (10) operating experience.

The application states that corrective actions, the confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subjected to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of this SER and is not discussed further in this section.

Erosion/corrosion can be mitigated to some degree by controlling water chemistry, which is achieved by the Chemistry Control Program *(Preventive Actions).* The other method for controlling the damaging effects of erosion/corrosion is timely detection and appropriate corrective actions. The applicant's piping erosion/corrosion program uses this other method.

The staff has reviewed the information in LRA Section 4.21, "Piping Erosion/Corrosion Program." The activities in this program are characterized by several attributes that the staff has evaluated to determine if they will adequately manage the aging effects during the period of extended operation. In general, the program follows the guidelines and recommendations of EPRI document NSAC–202L, Revision 1, concerning prediction, inspection, and repair and replacement of components damaged by erosion/corrosion. The applicant included in its piping erosion/corrosion program the following components of the MSS and FS: (1) the emergency feedwater pump turbine casing, piping, tubing, and valve bodies in the MSS, and (2) the emergency feedwater header, main feedwater header, piping, and valve bodies in the FS. The staff concludes that they represent the components susceptible to erosion/corrosion in the portion of the plant included in the LRA (*Scope of Program*). The computer code CHECWORKS, used by the applicant, predicts the components that may be damaged by erosion/corrosion and need to be inspected. It is an industrywide, well-established code that is being continually revised and improved (*Parameters Monitored or Inspected*). Using this program, the applicant will be able to evaluate the rate at which component wall thinning by erosion/corrosion is occurring (*Monitoring and Trending*). Wall thickness is measured by ultrasonic testing or by radiography, which are standard, well-developed techniques producing reliable results (*Detection of Aging Effects*). The criterion for component replacement is based on allowable minimum wall thickness determined by the component design code of record. The requirements of this code for bending and/or torsional stresses in the pipe from other loadings and pressure design (hoop stress) are included in the review. These other loadings are defined by the ONS design and include, but are not limited to, stresses from the dead weight of the piping system, thermal expansion, earthquake loadings, and dynamic fluid transients. Using these methods and applying this replacement criterion, the applicant will be able to successfully manage all the plausible aging effects caused by erosion/corrosion (*Acceptance Criteria*). The program has been successful in managing loss of material from erosion/corrosion, and since its inception no steam leaks have occurred in the portions of the systems within the scope of license renewal. Only one section of piping associated with the feedwater bypass control valve discharge has required replacement and no component replacement has been necessary in the main steam system (*Operating Experience*). The staff finds the applicant's piping erosion/corrosion program acceptable.

Main Steam System

The methods used by the applicant for managing aging effects on the components in the MSS consist of monitoring and controlling the aging effect directly or monitoring and controlling the conditions that contribute to the onset and propagation of a specific aging effect. The applicant has two programs applicable to managing aging effects: the chemistry control program and the piping erosion/corrosion program. The function of the chemistry control program is to control the conditions leading to different types of corrosion, including erosion/corrosion. The applicant's chemistry control program is evaluated in Section 3.2.2 of this SER. In addition, the applicant's piping erosion/corrosion program directly monitors aging effects from erosion/corrosion and specifies corrective actions to be taken in case damage is detected. This program is applicable to the MSS because this system contains carbon steel components susceptible to erosion/corrosion.

By using the chemistry control program and the piping erosion/corrosion program, the applicant will ensure that all the aging effects will be properly managed and that the MSS will perform its intended functions in accordance with the CLB during the period of extended operation.

Condensate System

The method used by the applicant for managing aging effects from loss of material from carbon steel components exposed to treated water in the CS consists of monitoring and controlling water chemistry through the chemistry control program. For the components in the secondary side of the main condensers and condensate coolers in the CS, which are exposed to raw water, the aging effects will be managed by the service water piping corrosion program, which is evaluated in Section 3.2.13 of this SER. The aging effects of the stainless steel tubes exposed to raw water in the main condensers of the CS are managed by the applicant through the preventive maintenance activity assessment program evaluated in Section 3.2.10 of this SER. The aging effects of material loss by selective leaching from the cast iron components are managed by the cast iron selective leaching program evaluated in Section 3.2.8 of this SER. The raw water environment is also responsible for a loss of material from carbon steel components when coupled with other more noble metals. The applicant will manage this aging effect by the galvanic susceptibility inspection program evaluated in Section 3.2.9 of this SER. The staff concludes that application of the chemistry control, service water piping corrosion, preventive maintenance activity assessment, cast iron selective leaching, and galvanic susceptibility inspection programs will allow the applicant to properly manage the aging effects and ensure that the CS will perform its intended functions during the period of extended operation.

Emergency Feedwater System

The EFS system has components made from stainless, low-alloy, and carbon steel. These components may be susceptible to corrosion when exposed internally to water without proper water chemistry control. The applicant will manage any resulting aging effects by directly monitoring and controlling water chemistry following the guidance specified in the chemistry control program evaluated in Section 3.2.2 of this SER.

Feedwater System

Internally, the components in the FS system are exposed to treated water, which operates at a temperature sufficiently high to make the erosion/corrosion mechanism a plausible aging effect. The applicant's aging management methodology is based, therefore, on two programs: the chemistry control program, evaluated in Section 3.2.2 of this SER, for controlling the conditions that could lead to the onset and propagation of the aging effects in both carbon and stainless steel components, and the piping erosion/corrosion program, which provides means for predicting which of the carbon steel components are susceptible to erosion/corrosion and specifies how the inspection of these components is to be performed and what corrective action should be taken. Application of these two programs will ensure that all the relevant aging effects will be properly managed and that the FS will adequately perform its intended functions in accordance with the CLB during the period of extended operation.

3.7.4 Conclusions

The staff has reviewed the information in Sections 3.5.9 and 4.21 of Exhibit A of the LRA and additional information provided by Duke in response to the staff RAIs. On the basis of this review, the staff concludes that Duke has demonstrated that aging effects associated with the subject systems will be adequately managed so there is reasonable assurance that the subject systems will perform their intended functions in accordance with the CLB during the period of extended operation.

3.8 Structures and Component Supports

3.8.1 Introduction

Duke described its aging management review (AMR) of the structures and component supports in the following sections of Exhibit A to its license renewal application (Ref. 1, license renewal application [LRA]): Section 3.4.11, "Class 1 Components Supports (CS)"; Section 3.7, "Aging Effects for Structural Components (SC)"; Section 4.3.6, "Once Through Steam Generator Upper Lateral Support Inspection"; Section 4.4, "Battery Rack Inspections"; Section 4.11, "Crane Inspection Program"; Section 4.12, "Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances"; Section 4.14, "Elevated Water Storage Tank Civil Inspection"; Section 4.15, "Federal Energy Regulatory Commission (FERC) Five Year Inspection"; Section 4.20, "Penstock Inspection"; Section 4.28, "Tendon-Secondary Shield Wall — Surveillance Program"; and Section 4.29, "230 kV Keowee Transmission Line Inspection." The staff reviewed these sections of the application to determine whether the applicant has demonstrated that the effects of aging on the structures and component supports will be adequately managed during the period of extended operation as required by 10 CFR 54.21(a)(3).

Additionally, in its September 30, 1999 letter to the Nuclear Regulatory Commission (NRC) titled, "Amendment 1 - CLB Changes for 1999 Application to Renew the Operating Licenses, Oconee Nuclear Station," the applicant stated that its plant modification to add the essential siphon vacuum system, the siphon seal water system, the essential siphon vacuum trenches and the essential siphon vacuum building was identified as one of three items that would materially affect the contents of the application. The applicant's determination necessitated staff inclusion of both the essential siphon vacuum trenches and the essential siphon vacuum building within the scope of the AMR under Section 3.8.

3.8.2 Summary of Technical Information in the Application

3.8.2.1 Structures and Components Subject to an Aging Management Review

Section 2.7 of Exhibit A of the LRA contains the information required to identify the Oconee Nuclear Station (ONS) structural components that are subject to an AMR for license renewal pursuant to 10 CFR 54.21(a)(1) and (a)(2). Section 2.7.1 of Exhibit A of the LRA provides a description of the process used to identify structural components subject to an AMR. Section 2.7.2 of Exhibit A of the LRA identifies the generic list of structural components that have been determined by the applicant to require an AMR. The list of ONS structures that have been determined to be subject to an AMR follows:

- Auxiliary buildings, which includes hot machine shop, spent fuel pools for Units 1 & 2 (shared), and Unit 3
- Earthen embankments, including the intake canal dike, Keowee River dam, and Little River dam and dikes
- The intake structure
- Keowee structures, which include the breaker vault, intake structure, penstock, powerhouse, service bay structure, and spillway
- The reactor building's internal structure and unit vent stacks
- The standby shutdown facility
- Turbine buildings, which include switchgear enclosures for Units 1 & 2 (shared) and Unit 3
- Yard structures, which include all areas and components outside the other buildings; specifically, the 230 kV Keowee transmission line towers, 230 kV switchyard structures and relay house, trenches, the elevated water storage tank, Keowee's transformer yard, and the ONS' transformer yard
- Essential siphon vacuum trenches
- Essential siphon vacuum building

Aging Management Review

The functions of the structures were determined from a review of information contained in the ONS updated final safety analysis report (UFSAR) and other related documentation. To facilitate aging management review, the applicant classified the structural components for the above listed structures into four categories, as follows:

- Concrete structural components
- Steel structural components in an air environment
- Steel structural components in a fluid environment
- Fire barriers

Sections 2.7.2.1, 2.7.2.2, 2.7.2.3, and 2.7.2.4 of Exhibit A of the LRA list individual items included in each of the above four component categories. Sections 2.7.3 through 2.7.10 of Exhibit A of the LRA provide descriptions of each of the ten structures listed above that are subject to an AMR.

Class 1 component supports are identified in Section 2.4.11 of the LRA. Class 1 component supports subject to an AMR are:

- RCS Class 1 piping supports
- Pressurizer supports
- The reactor vessel support skirt
- The control rod drive service structure
- The OTSG supports
- The RCP supports

The aging effects for anchorage and embedments associated with these supports are addressed in Section 3.7.7 of the LRA. The approach for identifying the applicable aging effects on Class 1 component supports is described in Section 3.4.1 of the LRA.

3.8.2.2 Effects of Aging

3.8.2.2.1 Applicable Aging Effects for Concrete Structural Components

Section 3.7.2.1 of Exhibit A of the LRA discusses the considerations and basis adopted by the applicant in identifying applicable aging effects for concrete structural components.

The applicant determined the applicable aging effects that could result in loss of function of concrete structural components to be the following:

- Loss of material from concrete structural components from abrasion and freeze-thaw at the ONS intake structure and the Keowee intake structure, penstock, and spillway
- Cracking of equipment pads from fatigue
- Cracking of unreinforced masonry block and brick walls
- Change in material properties from leaching at the Keowee intake structure, penstock, spillway, and powerhouse

3.8.2.2.2 Applicable Aging Effects for Steel Structural Components in an Air Environment

Section 3.7.2.2 of Exhibit A of the LRA discusses the considerations and basis adopted by the applicant in identifying applicable aging effects for steel structural components in an air environment.

The applicant reviewed the steel structural components and identified the following aging effects to be applicable to steel structural components in an air environment:

- Loss of material from corrosion when the component is not coated
- Cracking from stress corrosion of high-strength bolting used in the steam generator support skirt and reactor vessel support skirt

3.8.2.2.3 Applicable Aging Effects for Steel Components in a Fluid Environment

Section 3.7.2.3 of Exhibit A of the LRA discusses the considerations and basis adopted by the applicant in identifying applicable aging effects for steel components in a fluid environment.

The applicant reviewed the steel components in a fluid environment and identified the following aging effects to be applicable to steel components in a fluid environment:

- Loss of material for uncoated carbon steel in a raw water environment
- Loss of material for stainless steel in a borated water environment
- Cracking of stainless steel in a borated water environment

3.8.2.2.4 Applicable Aging Effects for Fire Barriers

Section 3.7.2.4 of Exhibit A of the LRA discusses the considerations and basis for identifying applicable aging effects for fire barriers. The applicant determined that cracking and separation are the applicable aging effects that could result in loss of function of the ONS fire barrier penetration seals.

3.8.2.2.5 Auxiliary Building

The applicant evaluated aging effects for auxiliary building structural components subject to an AMR. It determined that aging effects from the following should be managed for license renewal:

- Cracking of equipment pads, masonry block, and brick walls
- Loss of material from structural steel beams, columns, plates, trusses, checkered plate, crane rails and girders, and flood, pressure and specialty doors, battery racks, anchorages/embedments, and cable tray/conduit and equipment supports
- Loss of material and cracking of spent fuel pool liner, spent fuel rack, and structural steel in the spent fuel pool
- Loss of material of fire doors, cracking of fire walls, and cracking and separation of fire barrier penetration seals

3.8.2.2.6 Earthen Embankments

The applicant evaluated aging effects for the earthen embankments subject to an AMR. The applicant determined that the aging effects from the following should be managed for license renewal:

- Loss of material due to erosion
- Cracking due to settlement

3.8.2.2.7 Intake Structure

The applicant evaluated aging effects for those components of the intake structure subject to an AMR that are identified in Section 2.2.3.6.3 of this SER. The applicant determined that loss of material is the applicable aging effect for intake structure components, and that it should be managed for license renewal. Intake structure components affected by loss of material are:

- Reinforced concrete beams, columns, floor slabs, and walls
- Anchorages/embedments
- Cable tray and conduit supports
- Trash racks
- Screens
- Checkered plates
- Equipment component supports
- Structural steel beams
- Columns
- Plates
- Trusses
- Pipe supports
- Expansion anchors
- Instrument racks and frames

Staff evaluation of intake structure components is discussed in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER.

3.8.2.2.8 Keowee Structures

The applicant evaluated aging effects for the Keowee structures subject to an AMR. The applicant determined that the following applicable aging effects for the intake structure should be managed for license renewal:

- Cracking of equipment pads, masonry block, and brick walls
- Loss of material of penstock, intake, spillway, anchorages/embedments, battery racks, cable tray and conduit supports, checkered plates, equipment component supports, expansion anchors, specialty doors, instrument line supports, instrument racks and frames, pipe supports, stairs, platforms and grating supports, structural steel beams, columns, plates and trusses, and crane rails and girders
- Change in material properties of penstock, intake, spillway, as well as reinforced concrete beams, columns, floor slabs, roof slabs, and walls

Aging Management Review

Staff evaluation of Keowee structural components is discussed in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER.

3.8.2.2.9 The Reactor Building's Internal Structural Components and Unit Vent Stacks

The applicant evaluated aging effects for the reactor building's internal structural components subject to an AMR. The applicant determined that the following applicable aging effects for reactor building internal structural components should be managed for license renewal:

- Cracking of equipment pads, masonry block, and brick walls
- Loss of material of anchorages/embedments; cable trays and conduits; cable tray and conduit supports; checkered plates; crane rails and girders; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); instrument line supports; instrument racks and frames; lead shielding supports; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates, and trusses; sump screens; and unit vent stacks
- Cracking of anchorage for the once through steam generator (OTSG) and the reactor vessel support
- Loss of material and cracking of the fuel transfer canal liner plates

Staff evaluation of the reactor building's internal structural components and unit vent stacks are discussed in Section 3.8.3.1.9 of this SER.

3.8.2.2.10 The Post-Tensioning System

The applicant evaluated aging effects for the tendon wire and tendon anchorage portions of the post-tensioning system subject to an AMR. The applicant determined the loss of material and cracking of the post-tensioning system are the applicable aging effects for the post-tensioning system that should be managed. Staff evaluation of the post-tensioning system is discussed in Section 3.8.3.2.5 of this SER.

3.8.2.2.11 The Standby Shutdown Facility

The applicant evaluated aging effects for portions of the standby shutdown facility (SSF) subject to an AMR that are discussed in Section 2.2.3.6.6 of this SER. The applicant determined that the following applicable aging effects for the SSF should be managed for license renewal:

- Cracking of equipment pads

- Loss of material of anchorages/embedments; battery racks; cable tray and conduit supports; checkered plates; crane rails and girders; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); HVAC duct supports; instrument line supports; instrument racks and frames; pipe supports; stair, platform, and grating supports

Staff evaluation of SSF components is discussed in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER.

3.8.2.2.12 The Turbine Building

The applicant evaluated aging effects for the portions of the turbine building subject to an AMR that are discussed in Section 2.2.3.6.7 of this SER. The applicant determined that the following aging effects should be managed for license renewal:

- Cracking of equipment pads, masonry block walls, brick walls, and fire walls
- Loss of material of anchorages/embedments; cable tray and conduit supports; checkered plates; crane rails and girders; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); instrument line supports; instrument racks and frames; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates, and trusses; and fire doors
- Cracking and separation of fire barrier penetration seals

Staff evaluation of turbine building components is discussed in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER.

3.8.2.2.13 Yard Structures

The applicant evaluated aging effects for yard structures, essential siphon vacuum trenches, the essential siphon vacuum building, and structural components subject to an AMR. The applicant determined that the following aging effects should be managed for license renewal:

- Cracking of equipment pads, masonry block walls, and brick walls
- Loss of material of anchorages/embedments; 230 kV switchyard battery racks in the relay house; cable tray and conduit supports; checkered plates; elevated water storage tank; equipment component supports; expansion anchors; pipe supports; structural steel beams, columns, plates, and trusses; instrument line supports; instrument racks and frames; and transmission towers.

Staff evaluation of the yard structure components is discussed in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER.

3.8.2.2.14 Class 1 Component Supports

The applicant evaluated aging effects applicable to the Class 1 component supports. As a part of its evaluation of applicable aging effects to the Class 1 component supports, The applicant also reviewed pertinent industry information, NRC generic communications, and ONS operating experience. The applicable aging effects for Class 1 component supports identified by the applicant in Section 3.4.11 of Exhibit A of the LRA are:

- loss of material by corrosion or boric acid wastage
- change in material properties of Lubrite pads in the OTSG upper lateral support structure

3.8.2.3 Aging Management Programs (AMPs)

3.8.2.3.1 AMP for Auxiliary Building

The applicant identified the following as the AMPs for the auxiliary building for license renewal:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (for Class 1, 2, and 3 piping and equipment component supports)
- Chemistry control program
- Fire protection program

The applicant concluded that these programs would manage the aging effects identified for the auxiliary building so that the functions of the auxiliary building would be maintained consistent with the current licensing basis (CLB) during the period of extended operation (refer to Table 3.7–1 of the LRA).

3.8.2.3.2 AMP for Earthen Embankments

The applicant identified the Federal Energy Regulatory Commission (FERC) 5-year inspection as the AMP for the earthen embankments for license renewal. The applicant concluded that the FERC-required 5-year inspection program would manage the aging effects identified for the earthen embankments so that the function of the earthen structures would be maintained consistent with the CLB during the period of extended operation.

3.8.2.3.3 AMP for Intake Structures

For the aging management of the intake structure and its components, the applicant relies on the inspection program for civil engineering structures and components as the program for managing the aging effects. The staff evaluation of the program is described in Section 3.2.6 of this SER. For pipe supports, the ISI plan, examination category F–A, has been identified as an additional AMP. The staff evaluation of this plan is described in Section 3.2.5 of this SER.

3.8.2.3.4 AMP for Keowee Structures

For the aging management of the Keowee structures and their components, the applicant relies on the following programs:

- Duke Power 5-year underwater inspection of hydroelectric dams and appurtenances
- FERC-mandated 5-year inspection
- Inspection program for civil engineering structures and components
- Penstock inspection
- Battery rack inspections (for the battery racks)
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (piping supports)

The staff evaluation of the inspection program for civil engineering structures and components is described in Section 3.2.6 of this SER. For pipe supports, the ISI plan, examination category F–A, has been identified as an additional AMP. The staff evaluation of this plan is described in Section 3.2.5 of this SER. The staff evaluation of battery rack inspections (for the battery racks) and the crane inspection program (for the crane rails and girders) are provided in Section 3.8.3.2.1 of this SER.

3.8.2.3.5 AMP for Reactor Building (Internal Structural Components and the Unit Vent Stacks)

The applicant determined that the following AMPs would be required to manage applicable aging effects for the reactor building (internal structural components and the unit vent stack):

- Inspection program for civil engineering structures and components
- Boric acid wastage surveillance program
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (for Class 1, 2, and 3 piping and component supports)
- Chemistry control program
- Tendon-secondary shield wall (SSW)-surveillance program

3.8.2.3.6 AMP for Standby Shutdown Facility

The applicant determined that the following AMP would be required to manage applicable aging effects for the SSF:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (for piping and equipment component supports)

3.8.2.3.7 AMP for Turbine Building

The applicant determined that the following AMP would be required to manage applicable aging effects for the turbine building:

- Inspection program for civil engineering structures and components
- Crane inspection program (for the crane rails and girders)
- Fire protection program

3.8.2.3.8 AMP for Yard Structures

The applicant determined that the following AMP would be required to manage applicable aging effects for the yard structures:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)
- 230 kV Keowee transmission line inspection
- Elevated water storage tank civil inspection

3.8.2.3.9 AMP for Class 1 Component Supports

The applicant determined that the following AMP would be required to manage applicable aging effects for Class 1 component supports:

- Inspection program for civil engineering structures and components
- Boric acid wastage surveillance program
- ONS ISI plan

3.8.2.4 Time-Limited Aging Analyses

In Section 5.7, Time-Limited Aging Analyses for Structures and Structural Components, of Exhibit A of the LRA, the applicant identified two time-limited aging analyses (TLAAs) applicable to the steel components in an air environment. For detailed discussions of TLAAs, refer to Section 4 of this SER.

3.8.3 Staff Evaluation

The staff reviewed the information in Section 5.7 of Exhibit A of the LRA to determine whether the applicant has demonstrated that the effects of aging on the structures listed in Section 3.8.2.1 of this SER and 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 (RAIs) that are discussed within the context of the staff evaluation below.

Aging Management Review

3.8.3.1 Effects of Aging

In Section 3.7.1 of Exhibit A of the LRA, The applicant describes the applicable aging effects for each of the following component groups:

- Concrete structural components
- Steel structural components in an air environment
- Steel structural components in a fluid environment
- Fire barriers

In assessing the aging effects on structural components, The applicant evaluated the potential for age-related degradation of the above-listed four structural component groups. As the age-related degradations are mainly caused by long-term exposure to sustained environmental conditions, the applicant has discussed such effects based on the existing knowledge about the aging effects of such environments on the structural components. The applicant cites a number of relevant NUREG reports, industry reports, and NRC Information Notices and Bulletins, which form the basis for the assessment of the aging effects on structural components. The applicant discussed the ONS operating experience for each group. Based on the combined information, The applicant identified aging effects that would require an AMP. The staff evaluation of the applicant's aging effect considerations for the structural components indicates that the applicant's identification of structural components, and the process used in identifying the aging effects for these components, are adequate and acceptable.

In the discussion of the aging effects on concrete components, the applicant appropriately evaluates aging effects such as loss of material from cavitation and abrasion, effects due to freeze-thaw, and cracking in the concrete components, including in the masonry block walls. However, there is no discussion related to the aging effects on caulking, expansion joints, and sealants. These nonmetallic components play important roles in maintaining the integrity of the connected components.

In view of the fact that expansion joints, caulking, and sealants (other than those for fire barriers) are not subjected to replacement based on qualified life or specified time period, the staff requested that the applicant explain why they should not be considered for an AMR as discussed in Sections 2.7 and 3.7 of Exhibit A of the LRA in accordance with 10 CFR 54.21(a)(1)(ii). In a letter dated February 8, 1999, Duke stated that, as the condition of these items are monitored under its inspection program for civil engineering structures and components, a specific AMR for these items is not necessary. As discussed previously in this SER, condition monitoring alone does not provide a basis for excluding components from an AMR. This was Open Item 2.2.3.6.1.2.1-1. The discussion of this aspect of the open item is provided in Section 3.8.3.1.8 of this SER.

In the discussion of the environment around the steel components in a fluid environment, The applicant stated that the ONS UFSAR limits the spent fuel pool temperature to 183 °F. A review of Section 9.1.3 of the UFSAR shows a limit of 150 °F for normal heat load and abnormal heat load when the three-pump-cooler configuration is in operation. It also shows a temperature limit of 205 °F for abnormal heat loads when the two-pump-cooler configuration is in operation. From the standpoint of aging effects assessment, sustained effects under normal heat load are important. The staff requests that the applicant clarify the discrepancy between the above-noted UFSAR temperature limits. If the real normal load limit is above 150 °F, the staff is concerned that, although the temperature of 183 °F may have no effect on the steel components, it could have a detrimental aging effect on the concrete of the spent fuel pool walls and slabs. The applicable code from the Standard Building Code Requirements for reinforced Concrete, ACI 349, limits the concrete temperature to 150 °F. This limit of 150 °F does not guard against additional cracking. However, it assures that the concrete properties, such as compressive strength and modulus of elasticity, would not be significantly affected. The applicant should discuss the aging effects of the temperature (183 °F) on the concrete cracking and concrete properties. This was Open Item 3.8.3.1–1.

In a letter dated October 15, 1999, Duke submitted its response to Open Item 3.8.3.1-1. In its response, the applicant stated that normal operating temperature for the spent fuel pool is below 150 °F (Reference Oconee UFSAR Section 9.1.3.1). Control room operators monitor spent fuel pool temperatures at all times in accordance with a periodic surveillance procedure, as required by Improved Technical Specifications (ITS 5.4.1). The applicant further stated that spent fuel pool normal operating temperatures range from approximately 90 °F to 120 °F and that these temperatures are well below the ACI 349 threshold where degradation would occur to concrete. Therefore, there are no applicable aging effects resulting from the temperature of the spent fuel pool. The applicant added that the temperature limit of 183 °F in Section 3.7.1 of Exhibit A of the LRA is incorrect. Bulk spent fuel pool temperatures for the spent fuel pools remain at or below 150 °F (UFSAR Sections 9.1.3.1 and 3.8.4.4). The applicant also noted that as discussed in Section 3.8.4.4 of the Oconee UFSAR, the spent fuel pool walls were analyzed for thermal loads. The staff evaluated the above applicant's discussion of how the spent fuel pool temperatures were monitored and controlled to remain below 150 °F at all times, including the applicant's clarification that the temperature limit of 183 °F in Section 3.7.1 of Exhibit A of the LRA is incorrect, and concluded that the applicant's response was adequate and acceptable. Thus, Open Item 3.8.3.1-1 is closed.

The discussion of the industry and ONS-specific experience database in Sections 3.7.1 and 3.7.2 of Exhibit A of the LRA does not capture (1) the essence of the results of the ONS baseline inspections that would have been performed during the implementation of the Maintenance Rule, and (2) the instances of the reported unusual events, such as the water leakage from the spent fuel pool liners. The conclusions drawn from this information could affect the applicable aging effects. This was Open Item 3.8.3.1-2.

Aging Management Review

In a letter dated October 15, 1999, Duke submitted its response to Open Item 3.8.3.1-2. In its response, the applicant stated that industry and Oconee-specific operating experience are included in the discussion in Sections 3.7.1 and 3.7.2 of Exhibit A of the LRA. More detailed information concerning the findings during the implementation of the Maintenance Rule are included in Section 4.19 of Exhibit A of the LRA. The applicant added that its review of the findings of the Maintenance Rule inspections did not result in the identification of any aging effects other than those already identified. Based on the above clarification, the applicant went on to assert that the conclusions of the Maintenance Rule civil inspections were taken into consideration during the aging effect evaluation and it was determined that the conclusions of the inspections did not change the applicable aging effects. The staff assessed this applicant's assertion and found it reasonable and acceptable. Therefore, Open Item 3.8.3.1-2 is closed.

The applicant submitted a general description of its process to determine the aging effects applicable to each of the four structural component categories. The staff evaluation of the four Duke processes follows.

3.8.3.1.1 Concrete Structural Components

The types of concrete structural components that are subject to an AMR are anchorages (in concrete), embedments (in concrete), equipment pads, flood curbs, foundation dowels, foundations, hatches, masonry block and brick walls, missile shields, pipe piles, roof slabs, reinforced concrete beams, columns, floor slabs, walls, sumps, and trenches.

The review to identify the applicable aging effects for concrete structural components considers the following potential aging effects:

- Loss of material (includes scaling, spalling, pitting, and erosion) from abrasion and cavitation, aggressive chemicals, corrosion of embedded steel and rebar, elevated temperature, or freeze-thaw
- Cracking from elevated temperature, fatigue, freeze-thaw, reaction with aggregates, shrinkage, or settlement
- Change in material properties from aggressive chemical attack, elevated temperature, irradiation embrittlement, or leaching of calcium hydroxide

Change in material properties is manifested in concrete components as increased permeability, increased porosity, reduction in pH, reduction in tensile strength, reduction in compressive strength, reduction in modulus of elasticity, and reduction in bond strength.

The applicant reviewed the concrete structural components with respect to the above elements of the aging effects and concluded that the applicable aging effects that could result in loss of function of concrete structural components are:

- Loss of material from concrete structural components from abrasion and freeze-thaw at the intake structure and Keowee intake structure, penstock, and spillway
- Cracking of equipment pads from fatigue
- Cracking of unreinforced masonry block and brick walls
- Change in material properties from leaching at the Keowee intake structure, penstock, spillway, and powerhouse

The staff finds the applicant's approach for evaluating the applicable aging effects that could result in loss of function of concrete structural components to be reasonable and acceptable. The staff concludes that the applicable aging effects have been identified for the concrete components.

3.8.3.1.2 Steel Structural Components in Air Environment

The types of steel structural components in an air environment that are subject to an AMR are:

- Anchorages and embedments (exposed surfaces)
- Battery racks
- Cable tray and conduits
- Cable tray and conduit supports
- Checkered plates
- Control boards
- Control room ceiling
- Crane rails and girders
- Electrical and instrument panels and enclosures
- Elevated water storage tank (exterior)
- Equipment component supports
- Expansion anchors
- Specialty doors (e.g., flood and pressure)
- HVAC duct supports
- Instrument line supports
- Instrument racks and frames

- Lead shielding supports
- Metal siding
- Piles
- Pipe supports
- Stairs
- Platforms
- Grating supports
- Structural steel beams
- Columns
- Plates and trusses
- Sump screens
- Transmission towers
- Unit vent stacks

The following potential aging effects have been identified for steel structural components in an air environment by the applicant based on its review of available industry literature and past operating experience:

- Loss of material from general corrosion
- Cracking from fatigue or stress corrosion cracking (SCC)
- Change in material properties from elevated temperatures or irradiation embrittlement

The structural steel components are typically coated. Degradation or damage to the coatings could result in local corrosion of steel components. If the corrosion is allowed to proceed for an extended period of time, the loss of material could affect the capability of the component to fulfill its intended function. The staff agrees that degradation or damage to the coatings with resultant corrosion of uncoated steel are credible effects of aging.

Metal housing systems such as electrical panels or cabinets constructed of galvanized sheet metal do not have a tendency to age with time, according to industry experience. Therefore, loss of material from corrosion is not an applicable aging effect for control boards, electrical panels, cabinets, and enclosures. The staff agrees that painted or galvanized sheet metal will not have a tendency to age with time and loss of material from corrosion is not an applicable aging effect.

Cable trays are constructed from galvanized sheet metal and would not have a tendency to age with time, according to industry experience. Therefore, loss of material from corrosion is not an applicable aging effect for cable trays. The staff agrees that galvanized sheet metal will not have a tendency to age with time and loss of material from corrosion of cable tray steel is not an applicable effect of aging.

Steel components that are not coated, such as the polar crane girders, or where there is a loss of coating are susceptible to corrosion and need to be inspected. Therefore, loss of material from corrosion is an applicable aging effect for components that are not coated or where there is a loss of protective coating. The staff agrees that uncoated steel and steel with degraded or lost coatings will be susceptible to corrosion and loss of material from corrosion is an applicable aging effect.

For SCC of steel to occur, a corrosive environment must be present; the steel must be susceptible to SCC; and a tensile stress, either applied or residual, must be present. The internal environments at the ONS do not contain aggressive chemicals under normal operating conditions. Therefore, the conditions necessary for SCC do not exist for cracking to occur on steel components at the ONS, with the exception of high-strength bolting. The staff agrees that, other than high-strength bolting, SCC of structural steel is not an applicable aging effect at the ONS.

The application states that industry experience has shown that high-strength bolting with yield strengths higher than 150 ksi could be susceptible to SCC in humid environments such as the reactor building. Two types of high-strength bolting were used at the ONS: ASTM A325 and ASTM A490. ASTM A325 has been excluded from review for SCC because it has a yield strength of less than 150 ksi, and industry experience indicates that no failures have been identified in similar applications. The ASTM A490 bolting is used for the reactor vessel support skirt and the steam generator support skirt. The ASTM A490 bolts have failed in similar applications in nuclear power plants from SCC. The application states that the failures resulted from improper heat treatment or the combination of high preload and a borated water environment. Cracking of the ASTM A490 bolting could result in insufficient support of the reactor vessel or the SG. Therefore, the applicant concludes that SCC of the ASTM A490 bolting is an applicable aging effect.

The staff notes that bolting with a tensile strength of higher than 150 ksi, rather than a yield strength of higher than 150 ksi as stated in the application, is susceptible to SCC. Bolting fabricated to either A325 or A490 may have tensile strengths in excess of 150 ksi. However, the applicant stated that no failures have been identified in A325 materials exposed to humid environments such as the reactor building. Therefore, the staff concludes that A490 is susceptible to SCC and that this is an applicable aging effect for A490, but concurs with the application that SCC is not an applicable aging effect for A325 bolting.

A change in material properties from elevated temperatures or irradiation embrittlement was determined not to be an applicable aging effect for steel structural components. The staff agrees that the temperatures are not sufficiently high to alter the properties of any of the structural steel components. Also, the level of irradiation does not exceed the threshold for irradiation embrittlement.

The applicant reviewed the aging effects for steel structural components and concluded that the applicable aging effects that could result in loss of function of the steel structural components in an air environment are:

- Loss of material from corrosion when the component is not coated
- Cracking from stress corrosion of high-strength bolting used in the steam generator support skirt and reactor vessel support skirt

The staff finds that the applicant's approach for the determination of applicable aging effects for structural steel components in an air environment is reasonable and acceptable. The staff concludes that the applicable aging effects have been identified for the steel components in an air environment.

3.8.3.1.3 Steel Structural Components in a Fluid Environment

Steel structures and structural components in a fluid environment are identified in Section 2.7 of the LRA. Consistent with the process described in Section 3.2, the applicable aging effects are determined by reviewing the materials of construction and ambient environments. Section 3.2 of Exhibit A of the LRA describes the fluid environments to which steel structural components are exposed in the ONS. Sections 3.7.2.3.2 through 3.7.2.3.6 of Exhibit A of the LRA describe the results when the process is applied to steel components in a fluid environment at the ONS.

The types of steel structures and structural components in a fluid environment subject to an AMR are:

- The elevated water storage tank (interior)
- Equipment component supports
- The fuel transfer canal liner plate
- The spent fuel pool liner plate
- Spent fuel storage racks
- Structural steel and plates
- Trash racks and screens

The applicant indicated that the potential effects of aging for the steel structural components in a fluid environment category are:

- Loss of material from crevice corrosion, galvanic corrosion, general corrosion, erosion, erosion-corrosion, microbiologically influenced corrosion (MIC), and pitting corrosion
- Cracking from fatigue, hydrogen damage, intergranular attack, or SCC
- Change in material properties from thermal embrittlement or irradiation embrittlement

The staff concludes that these are the primary potential effects of aging of steel structural components in a fluid environment.

The fluid environments in contact with steel structures and structural components are Lake Keowee water or borated water. The borated water is associated with the spent fuel pool and contains about 1,800 ppm boron. The water quality is monitored and controlled on a regular basis by checking chemical composition, pH, and other parameters. The normal spent fuel pool temperature is 120 °F and is limited to 150 °F in the ONS UFSAR.

Steel structures and structural components are susceptible to corrosion in systems that use raw water. Loss of material from general corrosion is an applicable effect of aging for the intake trash racks and screens, the elevated water storage tank, the intake equipment component supports, and the Keowee structural steel and plates. The staff finds that the raw water will cause corrosion of steel structures and structural components and that the applicant has identified the proper components.

MIC occurs in the presence of aerobic bacteria in aerated water and anaerobic bacteria in unaerated water. MIC is an applicable effect of aging for carbon and low-alloy steel in raw water for the intake trash racks and screens, the elevated water storage tank, the intake equipment and component supports, and the Keowee structural steel and plates. The staff agrees that MIC is an applicable effect of aging for carbon and low-alloy steel in raw water.

The application states that pitting corrosion can occur most commonly on passive materials such as wrought austenitic stainless steels. Pitting corrosion is more likely to occur in low-flow areas. Loss of material from pitting is an applicable effect of aging for the intake trash racks and screens, the elevated water storage tank, the intake equipment component supports, and the Keowee structural steel and plates. Pitting of carbon and low-alloy steels in raw water is common. Also, for some stainless steel, a minimum velocity is required to passivate the stainless steel and increases in velocity may increase the pitting rate. Crevice corrosion is more likely to occur in low-flow areas. However, the staff concludes that the end result is the same as the applicant proposes.

Aging Management Review

The application states that oxygen levels above 100 ppm are required to initiate pitting in wrought austenitic stainless steel in the presence of chlorides, fluorides, or sulfates. The applicant also states that low-flow conditions are required for pitting to occur. Loss of material from pitting is an applicable effect of aging for stainless steel in a borated water environment where chloride levels exceed 150 ppm in oxygenated stagnant and low-flow areas. The staff finds the applicant's evaluation of age-related pitting to be reasonable and acceptable.

The application states that for SCC to occur in stainless steel, the stainless steel must be sensitized, there must be oxygen present, and the temperature must be above 200 °F. Since the spent fuel pool temperature is limited to 150 °F, SCC of stainless steel is not an applicable effect of aging. The staff concludes that stainless steel will not be susceptible to intergranular SCC because of the temperature limits on the spent fuel pool.

If the chloride concentration exceeds 150 ppm in the spent fuel pool, SCC of austenitic stainless steel, particularly in the welds and heat-affected zone, is an applicable effect of aging. If the sulfate concentration exceeds 100 ppm, SCC of austenitic stainless steel, particularly in the welds and heat-affected zone, is an applicable effect of aging. The staff agrees that austenitic stainless steel will undergo transgranular SCC at the chloride concentrations and sulfate concentrations cited.

The applicant conducted a survey of industry experience for steel components exposed to a fluid environment and did not identify any additional effects of aging. The applicant also examined ONS's operating experience and no additional effects of aging were identified from this review for steel components and structures exposed to a fluid environment.

On the basis of the description of the steel components exposed to a fluid environment, the staff concludes that the applicant has included aging effects that are consistent with published literature, industry experience, and ONS experience.

The applicant reviewed all of the potential effects of aging and determined that the only applicable aging effects that could result in loss of function of the steel structural components in a fluid environment are:

- Loss of material for uncoated carbon steel in a raw water environment
- Loss of material for stainless steel in a borated water environment
- Cracking of stainless steel in a borated water environment

The staff finds that the applicant's approach for determining applicable aging effects for structural steel components in a fluid environment, as discussed above, is acceptable. The staff concludes that the applicant has identified the applicable aging effects for the steel components exposed to a fluid environment.

3.8.3.1.4 Fire Barriers

In Section 3.7.2.4 of Exhibit A of the LRA, the applicant identified the following fire barriers that are subject to an AMR:

- Fire doors (applicable aging effects are discussed in Section 3.7.2.2 of Exhibit A of the LRA)
- Fire walls (applicable aging effects are discussed in Section 3.7.2.1 of Exhibit A of the LRA)
- Fire barrier penetration seals

The applicant considered the following potential aging effects for identification of the applicable aging effects for fire barrier penetration seals:

- Loss of material from flaking
- Cracking from vibration, movement, or shrinkage
- Change in material properties from irradiation
- Separation from vibration, movement, or shrinkage

The applicant evaluated these potential aging effects with respect to the materials of construction and ambient environment of the fire barrier seals and determined the following are the only applicable aging effects that could result in loss of function of ONS fire barrier penetration seals:

- Cracking
- Separation

The loss of material from flaking is only applicable to the painted doors and walls and is not considered an aging mechanism for either doors or walls. In addition, irradiation of fire barriers is not a concern due to the low levels of exposure. The staff finds the approach used by the applicant in determining applicable aging effects for ONS fire barriers to be complete in scope and acceptable. The staff concludes that the applicable aging effects have been identified for the fire barriers.

Aging Management Review

The staff evaluations of the completeness and acceptability of the applicant's identification of applicable aging effects for specific ONS structural categories are provided below.

3.8.3.1.5 Auxiliary Building

The applicant evaluated aging effects for the auxiliary building subject to an AMR. The applicant determined that the aging effects are from (1) cracking of equipment pads, masonry block walls, and brick walls; (2) loss of material of structural steel beams, columns, plates, trusses, anchorages/ embedments, battery racks, and cable tray/conduit and equipment supports; (3) loss of material and cracking of spent fuel pool liner, spent fuel rack, and structural steel; and (4) loss of material of fire doors, cracking of fire walls, and cracking and separation of fire barrier penetration seals.

The applicant stated that auxiliary building concrete components are exposed to different service environments depending on their location. Below-grade portions of the concrete walls and foundation are exposed to backfill and groundwater. The groundwater chemistry plays a major role in the determination of the degradation of the below-grade components. External surfaces of the roof and walls above grade are exposed to the external atmospheric environment. The applicant indicated that the concrete components that are located internal to the auxiliary buildings are in controlled environments, which protect them from external weather and temperature changes. The staff concurs with these statements.

The applicant also stated that steel components of auxiliary buildings that are in an air environment are completely enclosed within the walls of the buildings and are exposed to an environment where the temperature and radiation exposure levels are less than the threshold levels where degradation may occur. In addition to the coating, which is applied to prevent oxidation from occurring, the low relative humidity of the auxiliary building ensures that oxidation, if it does occur, will progress at a very slow rate. The staff concurs with this assessment.

The auxiliary building steel components in fluid environments are the spent fuel pool liner, the spent fuel storage racks, and structural steel and plates. All these items are constructed of stainless steel and are exposed to borated water. The staff evaluation of steel components in a fluid environment is discussed in Section 3.8.3.1.3 of this SER.

Auxiliary building fire barriers include fire walls, fire doors, and penetration seals. These fire barriers are completely enclosed within the walls of the auxiliary building and are exposed to an environment where the temperature and radiation exposure levels are less than the threshold levels at which degradation may occur. The staff agrees with these statements.

With respect to Section 3.7.3.1, the staff issued RAI 3.7.3-1 related to aging effects on foundation settlement and asked Duke to discuss how the aging effects from settlement (including differential settlement) of auxiliary building concrete components will be managed. This RAI asked whether the concrete foundation of ONS's auxiliary building experienced any cracking degradation that might affect its ability to perform the intended safety function. If yes, Duke was asked to describe the incident(s) and indicate how the observed degradation was resolved. In response to RAI 3.7.3-1, Duke stated that cracking from settlement (and differential settlement) of inscope structures was identified as a potential aging effect in Section 3.7.2 of Exhibit A of the LRA. The amount of settlement of a structure depends on the physical properties of the foundation material. These properties range from rock (with little or no settlement likely) to compacted soil (with some settlement expected). The auxiliary building is founded on granite gneiss; therefore, cracking from settlement (including differential settlement) is not an applicable aging effect. The ONS auxiliary building concrete foundation has not experienced any cracking that might affect its ability to perform its intended functions. The staff considers Duke's response reasonable and acceptable.

In RAI 3.7.3-2, the staff raised the concern that degradation or corrosion of embedded steel and rebar in concrete is not listed as an applicable aging effect for the auxiliary building in Table 3.7–1. Since concrete cracking was observed in ONS and ingress of water through these cracks (e.g., foundation slabs) may lead to corrosion of the embedded steel and rebar, Duke was asked to discuss how corrosion of embedded steel and rebar in concrete from ingress of water through concrete cracks will be managed. In response, Duke stated that as described in Section 3.7.2.1.6 of Exhibit A of the LRA, concrete cracking was observed in an auxiliary building floor slab. The crack was determined to be the result of slab shrinkage during initial concrete placement. Ingress of groundwater is not possible through this crack because the crack is located in an internal, above-grade floor slab. Duke further stated that foundation slab cracks have not been identified as applicable aging effects and have not been validated by industry or ONS operating experience. ACI 318–63 suggests the minimum requirements for concrete cover for structures of conventional and prestressed concrete. These minimum values have proved to be effective for preventing chemical corrosion of the concrete reinforcement that exists in an environment not subject to special chemical exposures. The cover provided in the ONS structures meets or exceeds the requirements of ACI 318–63. The staff finds this response acceptable.

RAI 3.7.3-10 asked if the ONS units ever experienced cracking of the liner and leakage of spent fuel pool water. If yes, Duke was asked to discuss past experience and indicate how it intends to manage these aging effects for the extended period of operation. In its response, Duke stated that the ONS units have not experienced cracking of the liner and leakage of spent fuel pool water. The chemistry control program discussed in Section 4.6 of Exhibit A of the LRA manages cracking of the liner. The program controls impurities in the water that could lead to aging effects of components in the spent fuel pool. The staff considers Duke's response to be acceptable.

RAI 3.7.7-7 asked whether the fuel transfer canal liner ever experienced a leakage problem from SCC of sensitized parts of the liner (e.g., near the liner weld). If liner cracking and leakage were to occur from SCC without a leakage monitoring system in place, how could the applicant detect the liner leakage and take needed corrective action? Duke was asked to discuss the bases for concluding that monitoring and controlling of spent fuel pool chloride, together with monitoring of sulfate in the pool as a diagnostic parameter (per the ONS chemistry control program) without concurrent monitoring of spent fuel pool leakage or a means for determining the presence of cracks, will adequately manage age-related degradation from SCC of the fuel transfer canal liner. In its response, Duke stated that the fuel transfer canal liner has not experienced a leakage problem from SCC. To initiate SCC, three factors are necessary: stress, a corrosive environment, and a susceptible material. Elimination or reduction of any one of these factors will decrease the likelihood of SCC occurring. Duke further indicated that environmental factors play a large part in causing SCC in sensitized areas. One of the most aggressive contributors to SCC is the dissolved oxygen concentration. At higher temperatures (T > 200 °F), dissolved oxygen creates an aggressive environment that can lead to SCC of stainless steel.

Temperatures in the spent fuel pool environment are limited to temperatures of less than 200 °F; therefore, temperature does not play a role in SCC. The chemistry control program is credited with managing the environment that could lead to aging effects in the spent fuel pool. The ONS's chemistry control program is discussed in Section 4.6 of Exhibit A of the LRA. The ONS's primary chemistry control specifications contain information related to the spent fuel pool, including the liner plate. These specifications contain chemical parameter specifications, sampling and analysis frequencies, and corrective actions for primary chemistry control. By controlling the chemistry in the spent fuel pool, the chemical environment of systems and structures supplied by or in contact with the spent fuel pool water is controlled. Duke asserted that the effectiveness of the program is demonstrated by the excellent operating experience with systems, structures, and components included in this program. No chemistry-related degradation has resulted in loss of any component's intended function on any component for which the fluid chemistry is controlled. Continuous chemistry control manages the corrosive environment, thereby eliminating one of the required factors for SCC. Consequently, additional inspections are not required. The staff finds this response adequate and reasonable.

Staff RAI 3.7.3-11 asked about age-related degradation of neutron-absorbing materials (i.e., boraflex sheets) used in the ONS's spent fuel racks. The staff inquired as to whether these racks experience spalling and surface abrasion of the neutron-absorbing sheets. Duke was asked to discuss the extent of actual spalling it has experienced to date and the potential for the debris from spalling of the Boraflex sheets to accumulate in an asymmetrical fashion to partially clog some gaps between the spent fuel rack cells and fuel assemblies, resulting in partial loss of fuel cooling function. Duke was also asked how it plans to manage the potential accumulation of the debris resulting from this aging effect. In its response to the RAI, Duke stated that high-density-poison spent fuel storage racks were installed in the spent fuel pool shared by ONS Units 1 and 2 in 1981 and the ONS Unit 3 spent fuel pool in 1984. The NRC approved the installation of these racks by amendments to the ONS operating license. The spent fuel storage racks contain Boraflex, which is the trade name for a silicon polymer that contains a specified amount of Boron 10, which is used as the neutron absorber to assure that criticality control is met through the service life of the racks. The Boraflex panels are attached to the exterior of the ONS spent fuel storage rack cells by stainless steel wrappers that are spot-welded along the sides. The wrapper plate is formed to provide a close-fitting pocket that confines the Boraflex. The ends of the wrapper plates are closed by different means. In the ONS Units 1 and 2 storage racks, metal plates are abutted to the top and bottom ends of the wrapper plates. In the ONS Unit 3 storage racks, the ends of the wrappers are bent over. Duke indicated that Boraflex does not degrade by spalling or abrasion. In an irradiated state, Boraflex consists of boron carbide and crystalline filler materials that are held together by the residual polymer matrix that has become mostly amorphous silica. The amorphous silica matrix is somewhat soluble in the warm spent fuel pool water that may enter the unsealed Boraflex wrapper. Thus, over a period of time, the silica matrix dissolves into the spent fuel pool water and is subsequently removed by the demineralizers. As this occurs, the boron carbide and crystalline filler materials, which are insoluble, slump to the lower regions of the wrapper plate. This response fully addresses the RAI and the issue is closed. (The aging of Boraflex in spent fuel racks and its effect on criticality is addressed in Section 4.2.10 of this SER).

On the basis of the discussions presented in Sections 3.8.3.1.1 through 3.8.3.1.4 and Section 4.2.10 of this SER, and on the types of materials as well as the design codes and standards used for the design of the auxiliary building and components located within the building, the staff concludes that the licensee has identified the applicable aging effects.

3.8.3.1.6 Earthen Embankments

The applicant evaluated aging effects for the earthen embankments subject to an AMR. The applicant determined that the aging effects from (1) loss of material from erosion and (2) cracking from settlement should be managed for license renewal.

Loss of material in earthen structures is caused by erosion resulting from wind, rain, and surface runoff; subsurface seepage flow; or wave action. Of these potential erosion processes, The applicant identified (1) rain and surface runoff and (2) subsurface seepage flow as applicable aging effects. Wind erosion and erosion from shoreline wave action are not considered as applicable aging effects by the applicant because the earthen embankments are provided with ground cover and riprap. In addition, these two erosion processes have not been observed during any past inspections of the earthen embankments required by FERC. Because the foundations of all dams have some seepage under prolonged storage conditions, the applicant has identified subsurface seepage flow as an applicable aging effect. Indications of subsurface flow such as sudden unexplained water level drops, surface cracks, unexplained settlement, and new downhill springs are monitored by the applicant and by FERC-required inspections. The most recent inspection, in 1996, detected minor seepage. The corrective action plan implemented by the applicant and approved by FERC requires monthly monitoring with further specific actions for each affected area if further erosion is observed.

Subsurface loading leads to some settlement in all earthen structures. Sudden or rapid settlement resulting from subsurface flow may lead to differential settlement, which could cause transverse cracking of the earthen embankment. Although inspections of the dams and dikes at the ONS have not identified any significant settlement, cracking from settlement is considered by the applicant to be an applicable aging effect.

On the basis of the description of the dams and dikes at the ONS, the results of previous FERC-required inspections of these dams and dikes, and a nationwide survey of past dam incidents and accidents, the staff concludes that the licensee has identified the applicable aging effects.

3.8.3.1.7 The Intake Structure

The applicant evaluated aging effects for the intake structure subject to an AMR. The applicant determined that the following aging effects should be managed for license renewal:

- Loss of material from reinforced concrete beams, columns, floor slabs, and walls
- Loss of material of anchorages/embedments; cable tray and conduit supports; checkered plates; equipment component supports; expansion anchors; instrument racks and frames; pipe supports; stair, platform, and grating supports; trash racks and screens; and structural steel beams, columns, and plates

The applicant stated that intake structure concrete components are exposed to different service environments depending on their location. Below-grade portions of the concrete are exposed to backfill and groundwater. Portions of the concrete are also exposed to water from Lake Keowee. The groundwater and lake water chemistries play a major role in the determination of degradation of the concrete within these areas. External surfaces are also exposed to the atmospheric environment. The applicant also stated that steel components within the intake structure are exposed to the external atmospheric environment and to the waters of Lake Keowee. The applicant maintains that the temperature and radiation exposure levels are less than the threshold levels where degradation may occur. The applicant further stated that steel can corrode where an area of the protective covering is destroyed or otherwise removed and both oxygen and water are present. The applicant concluded that the above-listed aging effects must be adequately managed so that the intended functions of the intake structure will be maintained consistent with the current licensing basis for the period of extended operation. The staff concurs with the above statements and conclusion.

On the basis of the discussions presented in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER, and on the types of materials and the design codes and standards used for the design of the intake structure, the staff concludes that the licensee has identified the applicable aging effects for the intake structure.

3.8.3.1.8 Keowee Structures

The applicant evaluated aging effects for the Keowee structures subject to an AMR. The applicant determined that the following applicable aging effects for the intake structure should be managed for license renewal:

- Cracking of equipment pads, masonry block, and brick walls
- Loss of material from penstock, intake, and spillway; anchorages/embedments; battery racks; cable tray and conduit supports; checkered plates; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); instrument line supports; instrument racks and frames; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates, and trusses; and crane rails and girders
- Change in material properties from penstock, intake, and spillway and from reinforced concrete beams, columns, floor slabs, roof slabs, and walls

The applicant stated that Keowee concrete components are exposed to different service environments depending on their location. Below-grade portions of the concrete walls and foundations are exposed to backfill, groundwater, and lake water. The chemistries of the groundwater and lake water play a major role in the determination of the degradation of the below-grade components. Surfaces of the concrete above grade are exposed to the external atmospheric environment.

With respect to Section 3.7.6, staff RAI 3.7.6-1 asked Duke to discuss why the aging effects from settlement (including differential settlement) of Keowee structures need not be included as an applicable aging effect, and to address how this effect would be managed. In its response to the RAI, Duke stated that the amount of settlement of a structure depends on the physical properties of the foundation material. These properties range from rock (with little or no settlement likely) to compacted soil (with some settlement expected). The Keowee structures are founded on bedrock; therefore, settlement (including differential settlement) is not identified as an applicable aging effect. The staff finds this response to be acceptable.

RAI 3.7.6-2 asked Duke to clarify why degradation or corrosion of embedded steel and rebar in concrete are not listed as applicable aging effects for Section 3.7.6 of the LRA for the penstock, intake, and spillway components of Keowee structures, and to discuss the basis for excluding this potential aging effect (i.e., loss of material), which may result from some localized surface cracking of concrete and ingress of water through these concrete cracks. In its response to the RAI, Duke indicated that Section 3.7.2.1 of Exhibit A of the LRA identifies loss of material from corrosion of embedded steel and rebar as a potential aging effect for concrete structural components. Section 3.2 defines the process that is used to determine whether a potential aging effect is applicable for the particular structure material, stressor, and environment combination. Loss of material from corrosion of embedded steel and rebar was determined not to be an applicable aging effect for the Keowee penstock, intake, and spillway. Duke further stated that ACI 318–63 provides the minimum requirements for concrete cover for structures. These minimum values have proved to be effective for preventing chemical corrosion of the concrete reinforcement that exists in an environment not subject to special chemical exposures. The Keowee structures were designed in accordance with the requirements of ACI 318–63 and were not located in an environment subject to special chemical exposures. The design and installation of the concrete structures are sufficient to preclude corrosion of the embedded steel. Visible evidence of corrosion of embedded steel would be seen as rust stains on the exterior surface of the concrete. Evidence of corrosion has not been identified at Keowee.

Loss of material from Keowee penstock, intake, and spillway concrete may be caused by other mechanisms, as discussed in Section 3.7.2.1.2 of Exhibit A of the LRA. Loss of material will be managed by the programs identified in Section 3.7.6.1 and described in Chapter 4 of Exhibit A of the LRA. The staff considers the above response acceptable.

In staff RAI 3.7.6-4, Duke was asked to discuss the basis for not including waterproofing membranes in Table 3.7-4 of the ONS LRA if they were used in the Keowee structures' exterior walls and base slabs to protect the concrete foundations or inhibit infiltration/seepage of groundwater. Duke was also asked to discuss the ONS's approach to managing the effects of aging on the waterproofing membranes. Duke's response to the RAI stated that waterproofing membranes were not used in the Keowee structures to protect the concrete foundations or inhibit infiltration/seepage of groundwater. Duke's response, however, did not indicate whether the Keowee structure or other in-scope structures experienced any kind of seepage of groundwater or whether the groundwater leaching that might be anticipated at the construction joints was observed at the SSF during a recently performed scoping inspection at the ONS. Duke was requested to submit a list of the ONS in-scope structures that had or are experiencing observable seepage or leaching by groundwater from aging degradation of sealants and caulking in concrete components. Duke also was requested to discuss its approach for managing the aging effects. This information should be provided as part of Open Item 2.2.3.6.1.2.1-1.

In its response to Open Item 2.2.3.6.1.2.1-1, Duke stated (in its submittal dated October 15, 1999, and the amended response dated December 17, 1999) that reinforced concrete walls located below grade and flood curbs in the auxiliary buildings and the SSF provide a protective barrier for internal/external flood events. Caulking, sealants, and waterstops are used to seal joints in the walls and flood curbs, an important step in maintaining their integrity. Degradation of the caulking, sealants, and waterstops may result in loss of the ability of the walls and flood curbs to provide a flood barrier. Gross degradation of these materials would be required to allow enough water to seep through the joint to produce flooding. Duke indicated that degradation of these materials in the auxiliary buildings and the SSF is managed by the inspection program for civil engineering structures and components. The program is discussed in Section 4.19 of Exhibit A of the LRA. Although the primary area of concern for these materials is in the auxiliary buildings and the SSF, the same program is used for all in-scope structures. The program visually inspects concrete for evidence of degradation, which may include, but is not limited to, water in-leakage, leaching, peeling paint, or discoloration of the concrete. Inspection findings are evaluated to determine the appropriate corrective action, which may include monitoring or repair/replacement of the caulking or sealant. In the December 17, 1999, submittal, Duke also stated that the inspection program for civil engineering structures and components will be utilized to manage the aging effects due to degradation of caulking, sealant, and waterstops in the auxiliary building and SSF, which may include, but is not limited to, water in-leakage, leaching, peeling paint, or discoloration of the concrete.

Duke further stated that Oconee operating experience has identified instances where degradation of these materials has resulted in discoloration of the concrete and leaching in the Keowee Powerhouse, the auxiliary buildings, and the SSF. While Keowee concrete structures do not provide a flood barrier and water seepage is a normal occurrence in dam facilities, evidence of leaching and discoloration of concrete has been detected and corrective actions have been taken. For the auxiliary buildings and the SSF, caulking and sealants have been repaired or replaced. Where discoloration and leaching have been identified along joints with waterstops, the joint has been sealed on the inside surface of the concrete.

With respect to aging management of sealants associated with the control room pressure boundary, Duke stated that the control room boundary includes the walls, ceiling, floor, access doors, and penetrations for electrical and mechanical equipment. Aging of the control room boundary walls, ceiling, and floor is managed by the inspection program for civil engineering structures and components.

On the basis of the above discussion, Duke concluded that continued implementation of the inspection program for civil engineering structures and components will provide reasonable assurance that caulking, sealants, and waterstops will be maintained to support the intended functions of the auxiliary buildings, SSF, and control room pressure boundary in accordance with the CLB for the period of extended operation. The staff reviewed the aging management approach discussed above, including program contents, scope, and past operating and maintenance experience, and agrees with the applicant's conclusion. Accordingly, the staff considers that the part of Open Item 2.2.3.6.1.2.1-1 pertaining to aging management of caulking, sealants, and waterstops of in-scope structures is closed. Additional evaluations that pertain to aging management of sealants and caulking of the control room pressurization and filtering system and fire barrier penetration seals are evaluated in SER Sections 3.6.1 and 3.2.4, respectively.

The components located internal to the Keowee structures are protected from external weather and temperature changes. Steel components are completely enclosed within the walls of the Keowee structures and are exposed to a relatively benign environment. The temperature and radiation exposure levels are less than the threshold levels at which degradation may occur. Steel can corrode where an area of the protective covering is degraded and both oxygen and water are present. The Keowee steel components that are exposed to the waters of Lake Keowee are structural steel and plates. The identification of applicable aging effects for steel in a raw water environment is described in Section 3.7.2.3 of Exhibit A of the LRA. These aging effects must be managed adequately. The staff agrees with these statements. On the basis of the discussions presented in Sections 3.8.3.1.1 through 3.8.3.1.4 of this SER, and on the types of materials and the design codes and standards used for the design of Keowee structures and components located within the building, the staff concludes that the applicant has identified the applicable aging effects.

3.8.3.1.9 The Reactor Building's Structural Components

The applicant evaluated aging effects for the reactor building's structural components subject to an AMR. The applicant determined that the following applicable aging effects for the reactor building's structural components should be managed for license renewal:

- Cracking of equipment pads and masonry block and brick walls
- Loss of material from anchorages/embedments; cable trays and conduits; cable tray and conduit supports; checkered plates; crane rails and girders; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); instrument line supports and instrument racks and frames; lead shielding supports; pipe supports; stair, platform, and grating supports; structural steel beams, columns, plates, and trusses; sump screens; and vent stacks
- Loss of material and cracking of the fuel transfer canal liner plate and post-tensioning system
- Cracking of OTSG and reactor vessel support anchorage

The applicant stated that the reactor building's internal structure concrete components are exposed to the internal atmosphere of the reactor building. High temperature, humidity, and radiation play a major role in the potential degradation of the components located within this environment. The applicant also indicated that steel components, except for the unit vent stack, are completely enclosed within the walls of the reactor building. The temperature and radiation exposure levels within the reactor building and in the external environment are less than the threshold levels at which degradation may occur. The applicant acknowledged that steel can corrode where the protective coating is destroyed or otherwise removed and both oxygen and water are present. The staff concurs with these statements.

In RAI 3.7.7-2, the staff asked why degradation or corrosion of embedded steel and rebar in concrete is not listed as an applicable aging effect for the reactor building's structural components in Table 3.7-5. Since concrete elements within this category are exposed to a more severe atmosphere than that of the auxiliary building (e.g., higher temperature, humidity, and radioactivity), and the presence of some accumulated water on cracked slabs and walls of this category may lead to corrosion of embedded steel and rebar. Duke was asked to discuss its plan for managing the aging effects resulting from structural steel and rebar corrosion that are embedded in concrete from accumulation and ingress of water through concrete cracks. In its response, Duke indicated that Section 3.7.7.1 addresses the applicable aging effects for concrete components of the reactor building's internal structural components and refers to Section 3.7.2.1 for the identification of applicable aging effects. Section 3.7.2.1 lists the potential aging effects that were considered in the determination of the applicable aging effects. Loss of material from corrosion of embedded steel and rebar is identified as a potential aging effect of concrete structural components in Section 3.7.2.1 of Exhibit A of the LRA. Duke further stated that for water to enter the concrete, concrete cracking would need to occur.

Cracking may be caused by freeze-thaw, reaction with aggregates, shrinkage, settlement, elevated temperature, and fatigue. Cracking from freeze-thaw is not applicable because the reactor building's internal structural components are not exposed to the external environment. Cracking from reaction with aggregates is not applicable because the concrete constituents were carefully selected to mitigate aggregate reactions and tests were performed on the aggregate that proved they were not considered potentially reactive. Cracking from shrinkage is not applicable because shrinkage in concrete is not an issue after 20 years, as discussed in ACI 209R–82. Cracking from settlement is not applicable because the reactor building is founded on bedrock. Cracking from elevated temperature is not applicable because the concrete components are not exposed to the high temperatures necessary to induce aging effects. Cracking from fatigue is not an issue for the concrete components because the components are not exposed to cyclical loadings. As a result, cracking was determined not to be an applicable aging effect. Because cracking of the concrete is not applicable, loss of material from corrosion of embedded steel or rebar is not an applicable aging effect for the reactor building's internal structure concrete components. The staff finds the above response appropriate and acceptable.

Regarding the consideration of the applicability of the loss of material resulting from the aging effect to the ONS cable tray and conduit category, the applicant determined that the aging effect applies to those cable trays and conduits located within the reactor building; however, the same aging effect is not considered plausible for cable trays and conduits located in other parts of the ONS plants (refer to Tables 3.7-1 through 3.7-6 of the LRA). The applicant was requested to provide additional information to justify this differential treatment of the aging effect covering cable trays and conduits located in structures other than the reactor building. This was Open Item 3.8.3.1.9-1.

In a letter dated October 15, 1999, Duke submitted its response to Open Item 3.8.3.1.9-1. In its response, Duke stated that a review of Oconee-specific operating experience has not identified any aging effects for cable trays located in any structures except for those located in the reactor building. Duke indicated that loss of material of cable trays due to boric acid corrosion has been identified in that building. The cable trays in the building are located in areas that are susceptible to boric acid leakage. Duke, therefore, concluded that the loss of material due to corrosion is an applicable aging effect for the cable trays in the reactor buildings. Additionally, Duke also concluded that since loss of material due to corrosion has not been identified at the ONS or from industry experience for cable trays located in environments other than that of the reactor building, loss of material is not an applicable aging effect for cable trays in those locations. The staff reviewed the above applicant's justification and applicable industry as well as ONS-specific experience regarding loss of material due to corrosion of cable trays in various environments and concluded that the applicant's response to the Open Item is adequate and acceptable. On the basis of this staff conclusion, Open Item 3.8.3.1.9 -1 is closed.

The applicant stated that the reactor building's steel components in a fluid environment are the fuel transfer canal liner plates, which are constructed of stainless steel and exposed to borated water. The applicant determined that the fuel transfer canal liner plates are susceptible to loss of material and cracking. The staff agrees with this finding.

The applicant indicated that the aging effect that could potentially reduce the ability of the post-tensioning system to impose compressive forces is loss of material from corrosion and cracking. The applicant stated that loss of material and cracking must be considered for both the tendon wires and the anchorage providing the tendon wire terminations. Loss of material from pitting corrosion can occur in the presence of halide ions, particularly chloride ions. However, because anchorages located in the reactor building's internal atmosphere are not exposed to halide ions, the applicant concluded that loss of material from pitting is not an applicable aging effect for tendon wires and anchorage. The staff concurs with this finding.

The applicant indicated that cracking from stress corrosion results from the simultaneous presence of high-tensile stresses and an aggressive environment. The high-tensile stresses result from the prestressing of the tendons. The applicant asserted that the environmental factors known to contribute to SCC in carbon steels are hydrogen sulfide, ammonia, nitrate solutions, and seawater. Although the SSW tendons are not exposed to these environmental factors, they may be exposed to borated water, which could result in SCC. Therefore, cracking from stress corrosion is judged by the applicant as an applicable aging effect. The staff concurs with this finding.

The applicant reviewed the ONS's operating experience to validate the identified applicable aging effects for post-tensioning system components. This review included a survey of any documented instances of component aging and interviews with responsible engineering personnel. The ONS documentation identified tendon wire corrosion and surface corrosion of the tendon anchorage hardware. One ONS report documented corrosion of the tendon wire and anchorage. Specifically, on April 28, 1982, during the final reactor building's interior inspection on Unit 2, one SSW vertical tendon was found to be broken. Subsequent detailed inspections of the Units 1, 2, and 3 SSWs found one additional failed vertical tendon in Unit 2, no failures in Units 1 and 3, and some vertical tendons exhibiting corrosion in Units 2 and 3. The apparent cause of the corrosion was water accumulation in the bottom of the vertical tendon sheath. The corrosion had resulted in complete failure of all 90 of the 1/4-inch-diameter wires in the failed tendons. All failed tendons were replaced.

According to the applicant, the apparent cause of the failures was stress corrosion of the post-tensioning wires near the lower stressing washer, caused by water accumulating in the tendon covers and the lower portion of the tendon sheaths. Modifications were made to prevent the buildup of water in the tendon sheaths. In addition to the modifications, a surveillance program was designed to ensure that any future corrosion is detected and evaluated and that corrective action is taken to minimize additional deterioration. The applicant concluded, based on the above findings, that the ONS experience validates that loss of material from corrosion is an applicable aging effect for the tendon wires and anchorage when water is present. The staff concurs with this finding.

The staff concludes that the applicable aging effects have been identified for the reactor building's structural components.

3.8.3.1.10 The Standby Shutdown Facility

The applicant evaluated aging effects for the SSF components subject to an AMR. The applicant determined that the following applicable aging effects for the SSF should be managed for license renewal:

- Cracking of equipment pads
- Loss of material of anchorages/embedments; battery racks; cable trays and supports; checkered plates; equipment component supports; expansion anchors; specialty doors (e.g., flood or pressure); HVAC duct supports; instrument line supports; instrument racks and frames; pipe supports; and stair, platform, and grating supports

The applicant stated that the SSF concrete components are exposed to different environments depending on their location. Below-grade portions of the concrete walls and foundation are exposed to backfill and groundwater. The groundwater chemistry plays a major role in the determination of the degradation of the below-grade components. External surfaces of the roof and walls above grade are exposed to the external atmospheric environment. For these concrete components, The applicant did not identify any applicable aging effects except the cracking aging effect applicable to equipment pads and masonry walls.

The components located internal to the SSF are protected from external weather and temperature changes. Steel components are completely enclosed within the walls of the SSF and are exposed to a relatively benign environment. The temperature and radiation exposure levels are less than the threshold levels at which degradation may occur. The staff concurs with this applicant's determination because past operating experience of structural components subject to a similar environment tends to support the applicant's position.

The applicant further stated that steel can corrode where the protective coating is destroyed or otherwise removed and both oxygen and water are present, and that loss of material is the aging effect applicable to these steel components within the SSF. The applicant indicated that this aging effect must be adequately managed so that the intended functions listed in Table 2.7-6 will be maintained consistent with the CLB for the period of extended operation. The staff finds the applicant's identification of the above aging effects to be adequate and acceptable.

The staff concludes that the applicable aging effects have been identified for the SSF.

3.8.3.1.11 Turbine Building

The applicant identified that the structural components for aging management of the turbine building are concrete, steel, and fire barriers. Concrete components are exposed to different environments depending on their location. Below-grade portions of the concrete walls, foundation, and pipe piles are exposed to backfill and groundwater. The groundwater chemistry plays a major role in the determination of the degradation of the below-grade components. External concrete surfaces above grade are exposed to the external atmospheric environment. The components located internal to the turbine building are protected from external weather changes but may be exposed to higher temperatures and humidity. Based on the previous inspection results, The applicant identified cracking of equipment pads and masonry block and brick walls as applicable aging effects for concrete components, and will continue to use the inspection program for civil engineering structures and components to manage the aging effect. The staff agrees with this assessment and management of aging effects for concrete components because operating experience supports the applicant's position.

The applicant indicated that steel components are completely enclosed inside the walls of the turbine building and the temperature and radiation exposure levels are less than the threshold levels at which degradation may occur. The applicant also indicated that steel can corrode where the protective coating is destroyed or otherwise removed and both oxygen and water are present. The applicant identified corrosion as an aging effect for steel components, and will continue to use the crane inspection program and the inspection program for civil engineering structures and components to manage the corrosion aging effect. The staff agrees with this assessment and management of aging effects for steel components because experience indicates that steel corrosion is an aging effect and inspection is the usual way to identify corrosion.

The applicant stated that turbine building fire barriers include fire walls, fire doors, and fire barrier penetration seals. These fire barriers are completely enclosed within the walls of the turbine building and are exposed to a relatively benign environment where the temperature and radiation exposure levels are less than the threshold levels at which degradation may occur. The applicant indicated that the applicable aging effect for fire walls is concrete cracking as described in Section 3.7.2.1 of Exhibit A of the LRA, the applicable aging effect for fire doors is loss of material as described in Section 3.7.2.2 of Exhibit A of the LRA, and the applicable aging effects for fire barrier penetration seals are loss of material and separation as described in Section 3.7.2.4 of Exhibit A of the LRA. The applicant stated that it would use fire barrier inspections, a part of the fire protection program, as described in Section 4.16.1 of Exhibit A of the LRA, to manage these aging effects so that the intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicant further stated that its operating experience demonstrates that the fire barrier inspections had been effective in identifying deficiencies in penetration seals and that the inspection frequency is able to detect fire barrier degradation prior to loss of function. The staff finds the concept of using periodic inspections and preventive maintenance associated with the fire barrier inspections acceptable. The staff also finds the inspection frequencies described in Section 4.16.1.1 of the LRA to be reasonable because industry operating experience has confirmed their effectiveness.

3.8.3.1.12 Yard Structures

The applicant evaluated aging effects for the yard structures, essential siphon vacuum trenches and essential siphon vacuum building subject to an AMR. The applicant determined that cracking of concrete components and loss of material from steel components should be managed for license renewal. The applicant stated that concrete components of these structures are exposed to different service environments depending on their location. Below-grade portions of the concrete foundations are exposed to backfill and groundwater. The groundwater chemistry plays a major role in the determination of the degradation of the below-grade components. The components located inside of the structures (including the 230 kV relay house) are protected from external weather. Based on the previous inspection results, the applicant determined that the applicable aging effects for concrete components are cracking of equipment pads and cracking of masonry block and brick walls. The applicant stated that it would use the inspection program for civil engineering structures and components to manage the aging effect for concrete components. The staff concurs with this assessment because industry experience demonstrates that this type of concrete component cracking is usually identified by inspections.

The applicant indicated that steel components of these structures are either enclosed within the walls of the structures or exposed to the external environment. The temperatures and radiation exposure levels in both environments are less than the threshold levels at which degradation may occur. The applicant indicated that steel did corrode where the protective coating was destroyed or otherwise removed and both oxygen and water were present. The applicant stated that it would manage the aging effects of steel components by implementing the following programs:

- The inspection program for civil engineering structures for general steel structures as described in Section 4.19 of Exhibit A of the LRA
- Battery rack inspections for battery racks as described in Section 4.4 of Exhibit A of the LRA
- A 230 kV Keowee transmission line inspection as described in Section 4.29 of Exhibit A of the LRA, for the 230 kV Keowee transmission line structures
- An elevated water storage tank civil inspection, as described in Section 4.14 of Exhibit A of the LRA, for the elevated water storage tank

The staff finds that the applicant has identified a complete set of applicable aging effects for the yard structures, essential siphon vacuum trenches, and essential vacuum siphon building, and that its past inspection results have demonstrated that the listed inspection programs adequately managed the aging effects and are therefore acceptable for license renewal.

3.8.3.1.13 Class 1 Component Supports

The effects of aging are loss of material because of corrosion and boric acid corrosion of Class 1 component supports and change in material properties of OTSG Lubrite pads. On the basis of the description of the Class 1 component support environments and materials, the staff concludes that the applicant has included aging effects that are consistent with published literature, industry experience, and the ONS operating experience.

In RAI 3.4.11-2, the staff asked Duke to clarify whether the degradation of bolted connections potentially caused by vibration loading has been considered in the aging review for the Class 1 component supports, and if this effect is excluded, that Duke submit the basis for excluding this effect. In its response dated December 14, 1998, Duke stated that vibrational effects on the ONS Class 1 component supports have been considered in the design and construction of the bolted connections. The ONS design considered adequate preload of bolted connections. Bolting materials and torque were specified to ensure that design requirements were met, including consideration of vibrational loads. Duke also stated that a review of industry and ONS operating experience indicates that the bolted connections used in Class 1 component supports have not been subject to self-loosening by vibration. Therefore, vibrational loading effects have not been considered in the aging review for the ONS Class 1 component supports. On the basis of the clarification provided by Duke as discussed above, the staff finds this response to RAI 3.4.11-2 reasonable and adequate. On this basis, this issue is considered resolved.

In RAI 3.4.11-3, the staff asked Duke to clarify whether the loss of preload from rotating/reciprocating machinery had been considered in the aging effect review for the reactor coolant pump (RCP) supports and (if this effect is excluded) to present the basis for its exclusion. In a response dated December 14, 1998, Duke stated that loss of preload is not an applicable aging effect for the RCP supports because proper design has eliminated or compensated for its occurrence. Duke further stated that a review of industry data and ONS operating experience indicates that no degradation of RCP supports from loss of preload has been identified. On the basis of the clarification provided by the applicant, the staff finds Duke's response to RAI 3.4.11-3 reasonable and adequate. On this basis, this issue is considered resolved.

In RAI 3.4.11-4, the staff asked Duke to clarify whether any parts of Class 1 component supports described in Section 3.4.11 are inaccessible for inspection, and if so, to describe what AMP will be relied on to maintain the integrity of inaccessible areas. In a response dated December 14, 1998, Duke stated that Class 1 component supports include RCS piping supports and local restraints, pressurizer support plate frame assemblies, reactor vessel support skirt and control rod drive service structures, and OTSG and vertical support assemblies. All of these Class 1 component supports are accessible, as required, in order to perform inspections. Duke further indicated that a review of the current ONS ISI program confirmed that no relief requests have been requested for inspection of Class 1 component supports based on limited accessibility. On the basis of the information submitted by Duke, the staff finds this response to RAI 3.4.11-4 adequate and acceptable. On this basis, this issue is considered resolved.

Table 3.4-1 of the LRA indicates that the potential aging effect of cracking of Lubrite pads for the OTSG upper lateral support structure will be managed by the OTSG lateral support inspection program. Section 4.3.6 of Exhibit A of the LRA indicates that the subject inspection program is a one-time inspection. In RAI 3.4.11-5, the staff asked Duke to present the basis for not performing periodic inspections to track any future potential pad cracking from radiation effects during the period of extended operation. In a response dated December 14, 1998, Duke stated that change in material properties of the Lubrite pads could degrade the Lubrite surfaces, but that degradation or even loss of the Lubrite pad surface would not defeat the intended function of the OTSG upper lateral support structure. If the Lubrite surfaces were degraded, the underlying bronze on the support could be exposed to the carbon steel-bearing plate of the OTSG. Axial and radial movement of the OTSG would not be restricted because the coefficient of friction of the bronze is similar to that of the Lubrite and the OTSG upper lateral supports would be able to perform their intended functions (i.e., to provide support during seismic events or to transmit pipe rupture forces and dynamic forces to the SSW) even if the surface of the Lubrite pads were in a degraded condition.

Duke further indicated that no plant operating or maintenance history has identified degradation of the Lubrite pads. A one-time inspection at or near the end of the current term of operation is sufficient to assess the condition of the Lubrite pads. Periodic inspections are not necessary during the period of extended operation because the intended function of the OTSG upper lateral supports would be maintained with the Lubrite pads in a degraded condition. On the basis of the information submitted by the applicant, the staff finds this response to RAI 3.4.11-5 adequate and acceptable. On this basis, this issue is considered resolved.

In RAI 3.4.11-6, the staff asked Duke to present the basis for excluding mechanical wear as a potential aging effect for component supports containing pins, springs, or sliding plates. In a response dated December 14, 1998, Duke stated that loss of material from mechanical wear is not an applicable aging effect for springs, and pins of the Class 1 component supports. Mechanical wear under normal conditions could be caused by vibration and thermal growth. Vibrations from rotating/reciprocating machinery and thermal loads are considered in the design for the Class 1 component supports. Duke further indicated that both industry and ONS operating experience have not identified mechanical wear of the springs and pins. Therefore, mechanical wear is not an applicable aging effect of these pins and springs. With respect to component supports containing sliding plates, Duke indicated that sliding surfaces consisting of Lubrite pads are used on the OTSG upper lateral supports. As discussed in Duke's response to RAI 3.4.11-5, the OTSG upper lateral supports would be able to perform their intended function even if the surface of the Lubrite pads were in a degraded condition. Duke also stated that no plant operating or maintenance history has identified degradation of the Lubrite pads of Class 1 component supports. On the basis of the information submitted by Duke, the staff finds that this response to this RAI issue is reasonable and adequate. On this basis, this issue is considered resolved.

In Section 3.4.3.4 of Exhibit A of the LRA, the applicant indicated that there was an instance of cracking of a weld in a drain line off the pressurizer surge line. The applicant further states that the root cause of the weld cracking was determined to have been a combination of stress corrosion and mechanical vibration. In RAI 3.4.11-7, the staff asked Duke to present a summary description of the subsequent corrective actions to prevent the mechanical vibration for the subject piping system, as well as their associated supports, that may be affected by mechanical vibration. Duke was also requested to indicate whether these corrective actions are applicable to the period of extended operation, and if not, to present the basis for that determination. In its response dated December 14, 1998, Duke stated that the complete failure scenario of the subject weld in the drain line off the pressurizer surge line was crack initiation by SCC and propagation by a mixed mode of SCC and vibrational fatigue. Duke also stated that a fracture mechanics analysis of the welded connection that included a fracture flaw equivalent to those stipulated in Section XI of the ASME Code, and vibration stress based on the observed displacement of the piping, determined that the total stresses fall well below the endurance limit of the stainless steel. Therefore, the vibration in and of itself would not cause the failure. The analysis results revealed that no physical configuration changes were required to address the issue. The piping configuration was reinstalled according to the original design, and no corrective actions were required to mitigate any mechanical vibration effects. With respect to the stress corrosion crack, the licensee indicated that the crack that occurred on this line initiated at the outside diameter. The cause of the crack initiation is not known. However, there was a fire in this area and some of the chemicals used to fight the fire may have produced contaminants that caused the stress corrosion crack to initiate. Therefore, it was not a design-related SCC issue. On the basis of the information submitted by Duke, the staff finds that this response is reasonable and acceptable.

As required by 10 CFR 54.21(a)(1), the applicant performed an aging effects review (on a generic basis) for structural components in Sections 3.7.1 and 3.7.2 of Exhibit A of the LRA. The conclusions reached regarding the aging effects are used by the applicant in performing AMRs of the specific in-scope structures in Sections 3.7.3 to 3.7.10 of Exhibit A of the LRA. The staff considers the process used for reviewing and evaluating the aging effects on the in-scope structural components to be acceptable.

The staff concludes that the applicable aging effects have been identified for Class 1 component supports.

3.8.3.2 AMP for License Renewal

The staff evaluation of the Duke AMPs focused on the program elements rather than on details of specific plant procedures. To determine whether the Duke AMPs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of the program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that the corrective actions, confirmation processes, and administrative controls for license renewal are in accordance with the site-controlled corrective actions program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the corrective actions program is provided separately in Section 3.2.3 of this SER. These three elements will not be discussed further in this section. The remaining seven elements for the AMP for license renewal for structural steel components in an air environment are described in the sections of Exhibit A of the LRA indicated below:

- For the auxiliary building:

  – Battery rack inspections (Section 4.4)
  – Chemistry control program (Section 4.6)
  – Crane inspection program (Section 4.11)
  – Fire protection program (Section 4.16)
  – ONS ISI plan, examination category F–A (Section 4.18)
  – Inspection program for civil engineering structures and components (Section 4.19)

- For the intake structure:

  – The ONS ISI plan (Section 4.18)
  – Inspection program for civil engineering structures and components (Section 4.19)

- For Keowee structures:

  – Duke Power 5-year underwater inspection of hydroelectric dams and appurtenances (Section 4.12)
  – FERC Inspection (Section 4.15)
  – Penstock inspection (Section 4.20)

- For the reactor building:

  – Boric acid wastage surveillance program (Section 4.5)
  – Crane inspection program (Section 4.11)
  – Chemistry control program (Section 4.6)
  – ONS ISI plan, examination category F–A (Section 4.18)
  – Inspection program for civil engineering structures and components (Section 4.19)
  – Tendon SSW - Surveillance (Section 4.28)

The auxiliary building's steel components subject to a fluid environment are the spent fuel pool liner, the spent fuel storage racks, and structural steel and plates. All of these components are constructed from stainless steel and are exposed to borated water. The applicable effects of aging discussed in Section 3.7.2.3 of Exhibit A of the LRA will be managed using the chemistry control program described in Section 4.6 of Exhibit A of the LRA, which includes a discussion of the additional seven elements.

The intake structure steel components that are exposed to the waters of Lake Keowee are carbon steel trash racks and screens and equipment component supports. The applicable effects of aging will be managed using the inspection program for civil engineering structures and components described in Section 4.19 of Exhibit A of the LRA, which includes a discussion of the additional seven elements.

The Keowee steel components that are exposed to the waters of Lake Keowee are structural steel and plates. The applicable effects of aging will be managed using the Duke Power 5-year underwater inspection of hydroelectric dams and appurtenances (for intake steel) described in Section 4.12 of Exhibit A of the LRA and the penstock inspection (for penstock steel) described in Section 4.20 of Exhibit A of the LRA, which includes a discussion of the additional seven elements.

The reactor building's steel component in a fluid environment is the fuel transfer canal, which is constructed from stainless steel exposed to borated water. The applicable effects of aging will be managed using the chemistry control program described in Section 4.6 of Exhibit A of the LRA, which includes a discussion of the additional seven elements.

The elevated water storage tank is exposed to a raw water environment on the interior. The applicable aging effects for steel in a raw water environment are described in Section 3.7.2.3 of Exhibit A of the LRA. The applicable effects of aging will be managed using the elevated water storage tank civil inspection described in Section 4.14, which includes a discussion of the additional seven elements.

The staff's ONS plant structure-specific evaluations of AMPs are provided below.

3.8.3.2.1 AMP for the Auxiliary Building

The applicant identified the following as the AMPs for the auxiliary building:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)

- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (for Class 1, 2, and 3 piping and equipment component supports)
- Chemistry control program
- Fire protection program

Inspection Program for Civil Engineering Structures and Components

The purpose of the inspection program for civil engineering structures and components is to monitor and assess the condition of structures and components. The program requires that each structure or component be visually inspected from the interior and exterior where accessible. Inspections are performed by a team of at least two people. Inspectors are qualified by appropriate training and experience and approved by responsible ONS management. The nominal inspection interval is 5 years. The inspection interval may be increased to a nominal 10-year frequency with appropriate justification based on the structure, environment, and related inspection results. The acceptance criteria are no unacceptable visual indication of loss of material, no cracking or change of material properties for concrete, and loss of material for steel as identified by the accountable engineer. Inspected structures and components classified as acceptable are those structures and components that are capable of performing their intended function and are considered to meet the requirements contained in 10 CFR Part 50.65(a)(2) of the Maintenance Rule. Items that do not meet the acceptance criteria are evaluated by an accountable engineer for continued monitoring or for being corrected. Specific corrective actions will be implemented in accordance with the Duke quality assurance (QA) program.

The inspection program for civil engineering structures and components is an existing program at the ONS. The recent inspection results revealed no serious degradation or conditions that would adversely affect the ability of the structures or components to perform their intended functions. The staff concludes that the continued implementation of the inspection program for civil engineering structures and components provides reasonable assurance that the aging effects will be managed such that concrete and steel components will continue to perform their intended functions consistent with the CLB for the period of extended operation. The staff evaluation of this program is contained in Section 3.2.6 of this SER.

Battery Rack Inspections (for the battery racks)

Section 2.7.2.2 of Exhibit A of the LRA identifies battery racks as subject to an AMR. Section 3.7.3.2 of Exhibit A of the LRA identifies loss of material from corrosion as an applicable aging effect. Battery rack inspections are conducted on an annual basis in accordance with the

ONS improved technical specifications and will be used to manage the applicable aging effects for the extended period of operation.

The battery rack inspections are conducted to ensure that the structural integrity of the battery racks is maintained. The scope of the battery rack inspections include racks for 125 VDC instrumentation and control batteries at Keowee, 125 VDC 230 kV switchyard batteries, 125 VDC instrument and control batteries in the auxiliary buildings, and 125 VDC instrument and control batteries in the SSF.

The staff finds that the scope of the battery rack inspections is adequate because it includes inspections of key battery racks.

There are no preventive actions. The staff agrees that preventive actions are not needed.

The parameters inspected are the surfaces of the battery racks. The staff finds that surface inspections are appropriate for detection of surface corrosion of the battery racks.

Effects of aging are detected by the discovery of surface corrosion during the visual inspection of battery racks. The staff agrees that visual inspection can result in detection of the effects of aging on battery racks.

There was no monitoring or trending for surface corrosion of the battery racks. The staff agrees that monitoring and trending are not required for surface corrosion of the battery racks.

The acceptance criterion is no visual indication of loss of material from corrosion. The presence of physical damage or deterioration may not represent a failure. Any observed physical damage or deterioration is evaluated and shown that it does not affect the ability of the battery to perform its function. The staff finds that the acceptance criterion is acceptable and that physical damage or deterioration should be evaluated to see if the physical damage or deterioration affects the battery's ability to perform its function.

The applicant reviewed the ONS operating experience, and no instances of loss of material were identified for the ONS battery racks.

The staff concludes that the licensee has submitted enough information in its LRA to show that the battery rack inspection program is an effective AMP for managing corrosion of the battery racks.

Crane Inspection Program (for the crane rails and girders)

The purpose of the crane inspection program is to conduct periodic inspections and preventive maintenance on the ONS cranes and hoists.

Structural components associated with the cranes and hoists in the auxiliary building, the Keowee structure, the reactor building, the turbine building, and the SSF are included in the crane inspection program for license renewal. Because the scope includes all of the cranes in the protected area, the staff finds the scope to be acceptable.

There are no preventive actions and the staff agrees that preventive actions are not necessary.

The parameters monitored are the steel surfaces of cranes and hoists exposed to an air environment. The frequency of inspection for the cranes is based on guidance provided by ANSI B30.2.0. The frequency of inspection for the hoists is based on guidance provided by ANSI B30.16. The staff concludes that these are the pertinent parameters to be monitored and the appropriate frequencies on the basis of the ONS operating experience.

The staff finds the parameters inspected and the method of inspection acceptable because material loss or localized corrosion are detectable using visual inspections.

There are no monitoring or trending aspects to the crane inspection program and the staff did not identify a need for such.

The acceptance criterion is no unacceptable visual indication of loss of material as determined by the accountable engineer. The staff finds that the acceptance criterion is acceptable.

Previous crane and hoist inspections at the ONS revealed paint flaking on the crane girders, but an intact base coat of paint. No corrosion or rust were identified. The rails on the turbine aisle crane had to be replaced because of wear caused by misalignment during installation of the rails.

The staff concludes that the applicant provided enough information in its LRA to show that the crane inspection program is an effective AMP for maintenance of cranes and hoists at the ONS.

The applicant also proposed the following AMPs for aging effects management of components of the auxiliary building:

- ONS ISI plan, examination category F–A (for Class 1, 2, and 3 piping and equipment component supports)

- Chemistry control program
- Fire protection program

The staff evaluation of these programs is discussed in Section 3.2 of this SER.

In summary, the staff finds that the AMPs for the auxiliary building are acceptable.

3.8.3.2.2 AMP for Earthen Embankments

Section 4.15 of Exhibit A of the LRA credits the existing FERC 5-year inspection to manage the applicable aging effects identified for the earthen embankments at the ONS. As stated in the staff's evaluation and proposed resolution of License Renewal Issue No. 98–0100, "Crediting FERC-Required Inspection and Maintenance Programs for Dam Aging Management" (Ref. 2), many dams on nuclear sites are already subject to periodic inspection because of the Federal dam safety program, which was initiated in 1977. This program, developed in response to several fatal dam failures in the 1970s, encourages strict safety standards in the practices and procedures employed by Federal agencies or by dam owners regulated by the Federal agencies with regard to dam design, construction, inspection, maintenance, and management. The NRC relies on FERC to perform safety inspections of dams for which the NRC is responsible under this Federal dam safety program. Thus inspections, coupled with a maintenance/corrective action program, are an acceptable manner of managing degradation of dams. Therefore, for earthen embankments, dams, and related structures identified as being subject to an AMR, the staff concludes that continued compliance with requirements of FERC into the license renewal period, by virtue of that agency's authority and responsibility for ensuring that its regulated projects are constructed, operated, and maintained to protect life, health, and property, will constitute an acceptable dam AMP for the purposes of license renewal.

3.8.3.2.3 AMP for Intake Structures

The applicant used the conclusions from Sections 3.7.1 and 3.7.2 of Exhibit A of the LRA to identify the aging effects for which the items in each component group applicable to the intake structure are to be subjected to an AMR. The AMR indicated a number of items (e.g., anchorages in concrete) for which no applicable aging effects were identified. For the aging management of the identified components, the applicant relies on the inspection program for civil engineering structures and components as the program for managing the aging effects. The staff evaluation of this program is described in Section 3.2.6 of this SER. For pipe supports, the ISI plan, examination category F–A has been identified as an additional AMP. The staff evaluation of this plan is described in Section 3.2.5 of this SER. The staff concerns related to the content of Table 3.7–3 in Exhibit A of the LRA are discussed below.

Aging Management Review

In Section 3.7.5 of Exhibit A of the LRA, the applicant did not discuss the industry experience or ONS-specific experience related to the intake structure. In response to RAI 3.7.5-2, Duke presented a brief description of the results of prior inspections regarding cracking and degradation of concrete components and corrosion of intake structure steel components. In the response, Duke maintains its position regarding caulking, expansion joints, and sealants asserting that these items need not undergo aging management review because they are subject to replacement when found inadequate. According to 10 CFR 54.21(a)(ii), an AMR is required for components not subject to replacement on the basis of a qualified life or specified time period. The ad hoc replacement on the basis of the condition of these components does not fit the description for exclusion. Open Items 2.2.3.6.1.2.1-1 and 3.8.3.1-2 of this SER are applicable for the intake structures at the ONS.

As required by 10 CFR 54.21(a)(1), the applicant identified the intake structure's structural components that will be subjected to an AMR, and their corresponding AMPs. The applicant relies on the inspection program for civil engineering structures and components as the program for managing the aging effects on structural components in the intake structures at the ONS. The staff evaluation of this plan is described in Section 3.2.6 of this SER. Because Open Items 2.2.3.6.1.2.1-1 and 3.8.3.1-2 (discussed in Sections 3.8.3.1 and 3.8.3.1.8 of this SER) are resolved, the staff considers the programs utilized for managing the aging effects on the in-scope structural components in the intake structures at the ONS to be acceptable.

3.8.3.2.4 AMP for Keowee Structures

The applicant identified the following as the AMPs for the Keowee structures:

- Duke Power 5-year underwater inspection of hydroelectric dams and appurtenances
- FERC's 5-year inspection
- Inspection program for civil engineering structures and components
- Penstock inspection
- Battery rack inspections (for the battery racks)
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F-A (piping supports)

<u>Duke Power 5-Year Underwater Inspection of Hydroelectric Dams and Appurtenances</u>

Section 2.7.6 of Exhibit A of the LRA identifies the Keowee intake structure, spillway, and powerhouse as being subject to an AMR. Section 3.7.6 of Exhibit A of the LRA identifies loss of material from corrosion for steel components and loss of material, cracking, and change in material properties of concrete components as applicable aging effects for Keowee structures.

The applicant indicated that the 5-year underwater inspection of hydroelectric dams and appurtenances will manage these applicable aging effects for the period of extended operation. The purpose of the 5-year underwater inspection of hydroelectric dams and appurtenances is to inspect the structural integrity of the Keowee structures.

The scope of the 5-year underwater inspection of hydroelectric dams and appurtenances includes:

- Keowee intake — trash-racks, support steel, and concrete
- Spillway — concrete
- Powerhouse — concrete

The program requires visual examinations of external surfaces. The inspections are to be performed once every 5 years.

RAI 4.12-1, referring to Section 4.12.1 of Exhibit A of the LRA, requested Duke to indicate whether the 5-year visual examination of external surfaces covers 100 percent of the Keowee intake, spillway, and powerhouse's concrete surfaces exposed to water. If not, Duke was asked to indicate the approximate percentage of the exposed surfaces that will be examined and how the surfaces to be examined are selected. In its response to the RAI, Duke stated that the 5-year underwater inspection of hydroelectric dams and appurtenances is credited with managing aging of the Keowee intake, spillway, and powerhouse concrete surfaces exposed to water as described in Section 4.12 of Exhibit A of the LRA. The examination of external surfaces covers 100 percent of these surfaces. The concrete structures are inspected from the foundation to the free water surface. The staff accepts this response.

Duke stated that the 5-year inspection frequency is consistent with the periodicity of inspections performed by FERC for maintaining other components of the structures.

RAI 4.12-2 asked Duke to discuss its rationale for concluding that, on the basis of the results of past examinations, the 5-year inspection frequency is reasonable and acceptable to manage the aging effects on the underwater portions of the concrete and steel components of the ONS hydroelectric dams and appurtenances. In its response to the RAI, Duke stated that, as documented in Section 4.12 of Exhibit A of the LRA, underwater inspections have been performed for the Keowee structures since 1978. A review of previous 5-year underwater inspections of hydroelectric dams and appurtenances confirms the reasonableness and acceptability of the frequency in that degradation of the underwater portions of the Keowee concrete and steel components is detected prior to loss of function. Previous inspections have revealed only minor degradation. Inspection observations included loss of material from corrosion of steel components and loss of material of concrete components. Where unacceptable corrosion of steel components has been identified, the steel has been repaired or replaced. The concrete degradation was determined to result from inadequate vibration during construction and was not associated with aging. Other than the degradation noted, the concrete was determined to be in good condition. Operational experience validates that the frequency is acceptable in that no incidents of failure to perform intended functions of underwater concrete or steel components have occurred. The inspection frequency is consistent with the periodicity of inspections performed by Duke in accordance with FERC requirements for maintaining other components of the Keowee structures (see Section 4.15 of Exhibit A of the LRA for discussion of the FERC 5-year inspection). The staff concurs with this justification of the inspection frequency.

The applicant explained that the basic acceptance criteria for the program is no unacceptable visual indication of loss of material, cracking, or change in material properties as determined by the accountable engineer. The staff considers the criterion reasonable for Keowee-type structures.

The applicant stated that corrective actions for areas that do not meet the acceptance criteria are evaluated by the accountable engineer. If repair or replacement are required, then specific corrective actions will be implemented in accordance with the Duke QA program.

The applicant indicated that the program currently is performed in accordance with written guidance developed by the responsible Duke department. On the basis of the experience described previously, the applicant stated that the continued implementation of the 5-year underwater inspection for dams and appurtenances would supply reasonable assurance that the aging effects will be managed such that the Keowee intake, spillway, and powerhouse concrete and steel structures below water will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation. The staff concurs with this statement and finds the program acceptable.

Penstock Inspection

Section 2.7.6 of Exhibit A of the LRA identifies the Keowee penstock as being subject to an AMR. Section 3.7.6 of Exhibit A of the LRA identifies the applicable aging effects, which include loss of material, cracking, and change in material properties for the concrete and loss of material for the steel. The penstock inspection program will manage these applicable aging effects for the period of extended operation. In this regard, the applicant discussed the existing penstock inspection program and presented its operating experience in Section 4.20 of Exhibit A of the LRA.

The applicant indicated that the purpose of the penstock inspection program is to ensure that the structural integrity of the Keowee penstock will be maintained. The scope of the penstock inspection includes both the steel-lined and unreinforced concrete-lined sections of the Keowee penstock. The penstock inspection requires visual examination of the interior surface of the penstock. The applicant indicated that inspections are performed each time the Keowee penstock is dewatered during outages, which is at least every 5 years. The acceptance criterion is defined as no unacceptable visual indication of aging effects as identified by the accountable engineer. Areas that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service or corrected by repair or replacement.

Specific corrective actions are implemented in accordance with the Duke QA program. The program is performed in accordance with written guidance developed by the responsible Duke department. The applicant stated that previous penstock inspections have revealed only minor degradation of the Keowee penstock. Observations of past inspections include minor loss of concrete from abrasion. The applicant further stated that, other than the degradation noted, the Keowee penstock was determined to be in good condition.

On the basis of the above discussion of operating experience and inspection findings, the applicant concluded that the continued implementation of the penstock inspection would supply reasonable assurance that the aging effects will be managed such that the penstock will continue to perform its intended function consistent with the current licensing basis for the period of extended operation. The staff concurs with this conclusion and finds the penstock inspection program acceptable.

3.8.3.2.5 AMP for the Reactor Building's Internal Structural Components

The applicant identified the following as the AMPs for the reactor building's structural components:

- Inspection program for civil engineering structures and components
- Boric acid wastage surveillance program
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category FA (for Class 1, 2, and 3 piping and component supports)
- Chemistry control program
- Tendon-SSW-surveillance program

The evaluation of the inspection program for civil engineering structures and components is provided in Section 3.2.6 of this SER.

Aging Management Review

Refer to Section 3.8.3.2.1 of this SER for staff evaluations covering the crane inspection program. The staff evaluation of the boric acid wastage program, the ONS ISI plan, examination category F–A, and chemistry control program is provided in Section 3.2 of this SER.

Tendon-SSW Surveillance Program

Because of the continuing problem with the SSW post-tensioning tendon system, the applicant has developed a surveillance program for monitoring the integrity of the SSW post-tensioning tendons at periodic intervals. The program is an existing program, and the applicant stated that it will be continued through the license renewal period. The plan is discussed with respect to the 10 AMP elements in the following paragraphs.

Scope
The applicant identified the scope of the SSW surveillance program as tendon wire (corrosion) and integrity of tendon anchorage components. In response to Open Item 3.8.3.2.5-1 identified below, Duke agreed to monitor the prestressing forces in the SSW post-tensioning tendons. The staff finds the augmented scope acceptable.

Preventive Actions
In describing operating experience at the ONS, the applicant stated that modifications were made to prevent the buildup of water in the tendon sheaths. In addition to the modifications, a surveillance program was designed to ensure that any future corrosion and significant loss in prestressing force are detected and evaluated and that corrective action is taken to minimize additional deterioration. The staff considers the preventive actions implemented by the applicant to be adequate.

Parameters Monitored/Inspected
In describing the "aging effects" and "method," the applicant stated the applicable aging effects include loss of material from corrosion and cracking of tendon anchorage; wire force relaxation; loss of material from corrosion and breakage of wires; loss of material from corrosion and cracking of bearing plates; cracked, split, and broken buttonheads; and cracking and loss of material from corrosion of shims. The method used to monitor these effects is a visual examination of in-scope components and liftoff testing of the tendon system.

In response to RAI 2.7-8, Duke argued that maintaining the specified amount of prestressing force in the SSW is not part of the CLB and that prestressing force does not have to be monitored, predicted, or tracked for the license renewal period.

ONS UFSAR Section 3.8.3.3 (related to the internal structures of the steel containment) states that the loads and load combinations considered for the design of the interior structures are described in UFSAR Section 3.8.1.3. Section 3.8.1.3 discusses the "calculated prestressing force" (after consideration of appropriate losses) as a load to be considered in load combinations tabulated in Table 3–14. Thus, the staff believes that the SSW prestressing tendon system is part of the CLB. The applicant was requested to provide information demonstrating that the prestressing forces in the SSW will be adequately maintained for the period of extended operation. This was Open Item 3.8.3.2.5-1.

As documented in the December 10, 1999, meeting summary of the November 10, 1999, phone call on the SSW between the staff and the applicant, the applicant made changes to the sample size previously reflected in Section 4.28 of the LRA and agreed to monitor the prestressing forces in the selected tendons during each SSW post-tensioning system inspection. The staff finds the changes and parameters monitored to be acceptable.

Detection of Aging Effects

The surveillance program, together with the applicant's responses to RAIs 4.28-1 and 4.28-2, supply reasonable assurance that the applicable aging effects will be detected in a timely manner.

Monitoring and Trending

Although the staff had requested TLAAs related to the prestressing forces in SSW prestressing tendons, the applicant had insufficient data base to trend the prestressing forces. Instead, the applicant committed to monitor the prestressing forces in the SSW tendons as discussed in Parameters Monitored/Inspected.

Acceptance Criteria

In response to Open Item 3.8.3.2.5-1, Duke stated: "The acceptance criteria (for prestressing force in tendons) are administrative values that are equal to the minimum required force of a group of tendons plus a margin to preclude dropping below the minimum required force. The minimum required forces for the tendon groups range from 390 kips to 560 kips depending on the location of the group." For other parameters (e.g., corrosion), the applicant has established acceptance criteria in the program. The staff finds the applicant established acceptance criteria to be acceptable.

Corrective Actions

In response to Open Item 3.8.3.2.5-1, Duke stated: "In the event that a tendon lift-off falls below the acceptance criteria, the tendons would be subjected to corrective actions. Corrective action may include retensioning with reinspection during the subsequent inspection or complete replacement." In the program description in the LRA, the applicant stated: "Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. The actions taken during the past operating period and implementation of this program demonstrate that appropriate corrective actions will be taken." The staff finds the corrective action program acceptable.

Administrative Controls

The applicant stated that the tendon-SSW surveillance program is implemented by written procedures in accordance with the Duke QA program. The program is evaluated in Section 3.2.3 of this SER.

Operating Experience

The applicant has fully described the operating experience related to the SSW prestressing tendons and actions taken to alleviate the problems encountered in its operating experience. The staff finds the applicant's discussion of its SSW prestressing tendons operating experience and past corrective actions acceptable.

As required by 10 CFR 54.21(a)(1), the applicant identified the SSW tendons at the ONS as the long-lived passive structures requiring an AMR. The applicant identified the SSW post-tensioning tendon system as the vital component of the SSW, and developed a surveillance program to monitor and manage the aging effects of the components of the prestressing tendon system. As discussed above, Open Item 3.8.3.2.5-1 is closed. The staff finds this augmented AMP for tendon-SSW surveillance adequate and acceptable.

3.8.3.2.6 AMP for the Standby Shutdown Facility

The applicant identified the following as the AMPs for the SSF:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)
- Crane inspection program (for the crane rails and girders)
- ONS ISI plan, examination category F–A (for Class 1, 2, and 3 piping and equipment component supports)

The evaluation of the inspection program for civil engineering structures and components is provided in Section 3.2.6 of this SER. The inspection program is an existing program at the ONS. The recent inspection results revealed no serious degradation or conditions that would adversely affect the ability of the structures or components to perform their intended functions.

Refer to Section 3.8.3.2.1 of this SER for staff evaluations covering the battery rack and crane inspection programs and Section 3.2.5 of this SER for the staff evaluation of the ONS ISI plan, examination category F–A. The staff concludes that the continued implementation of the above-listed inspection programs supplies reasonable assurance that the aging effects will be managed such that concrete and steel components will continue to perform their intended functions consistent with the CLB for the period of extended operation.

3.8.3.2.7 AMP for the Turbine Building

The applicant identified the following as the AMPs for the turbine building:

- Inspection program for civil engineering structures and components
- Crane inspection program (for the crane rails and girders)
- Fire protection program

The staff's evaluation of the inspection program for civil engineering structures and components is discussed in Section 3.2.6 of this SER and the crane inspection program is discussed in Section 3.8.3.2.1 of this SER. The staff's evaluation of the fire protection program is provided in Section 3.2.4 of this SER.

Considering the results observed in past Duke inspections of building structures and the scope and contents of the above-listed AMPs, the staff finds these AMPs for the turbine building acceptable.

3.8.3.2.8 AMPs for Yard Structures

The applicant identified the following as the AMPs for the yard structures, essential siphon vacuum trenches, and essential siphon vacuum building:

- Inspection program for civil engineering structures and components
- Battery rack inspections (for the battery racks)
- 230 kV Keowee transmission line inspection
- Elevated water storage tank civil inspection

Aging management of yard structures, essential siphon vacuum trenches, and the essential siphon vacuum building consists of the inspection program for civil engineering structures and components, battery rack inspections, a 230 kV Keowee transmission line inspection, and an elevated water storage tank civil inspection. The staff evaluation of the inspection program for civil engineering structures and components is discussed in Section 3.2.6 of this SER and the staff evaluation of the battery rack inspection program is presented in Section 3.8.3.2.1 of this SER.

In Section 2.7.10 of Exhibit A of the LRA, the applicant identified the 230 kV Keowee transmission line towers as subject to an AMR. In Section 3.7.10 of Exhibit A of the LRA, the applicant identified loss of material as an applicable aging effect for steel components in an air environment, which includes the 230 kV Keowee transmission line towers. The staff considers the 230 kV Keowee transmission line inspection adequate to manage this aging effect.

230 kV Keowee Transmission Line Inspection

The purpose of the 230 kV Keowee transmission line inspection is to maintain the structural integrity of the transmission line structures. The scope of the inspection includes steel towers, concrete foundations, and hardware within the 230 kV Keowee transmission line. The applicable aging effects of concern include loss of material from corrosion of the steel structures and loss of material from spalling or scaling for concrete components. The inspection requires a visual examination of the towers and generally follows the guidance of the National Electric Safety Code, Part 2, Safety Rules for Overhead Lines; Rule 214 Inspection and Tests of Lines and Equipment. The inspections are performed once every 5 years. The acceptance criterion adopted is no visual indication of unacceptable aging effects as evaluated by the inspector. Areas that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented in accordance with the Duke QA program. According to the applicant, the 230 kV Keowee transmission line inspection is contracted through the ONS site engineering group with Duke's power delivery group. The inspection is implemented within the ONS preventive maintenance program.

The applicant indicated that visual inspections of the 230 kV Keowee transmission line, including the towers and hardware, from Keowee to the ONS have been performed since initial operation of the site. A review of completed 230 kV Keowee transmission line inspections confirms the reasonableness and acceptability of the inspection frequency in that degradation of the towers and hardware is detected prior to loss of function. Previous inspections found some instances of loose structural bolts and slight rusting of the structural members. Slight rust was found on the hardware where galvanizing was burnt off from flashing as a result of lightning strikes. The inspections have not identified wear on 230 kV line hardware. The hardware at the catchoff points at the turbine building were also inspected for corrosion, rust, and wear.

The staff evaluated the program contents, including the frequency of inspection, inspection procedural controls, and implementation of corrective measures and the operating experience of the applicant with respect to its implementation of the program. The staff finds the program adequate in scope and content to manage the aging effects of the 230 kV Keowee transmission line structures.

Elevated Water Storage Tank Civil Inspection Program

The elevated water storage tank civil inspection program includes the interior and exterior surfaces of the tank and associated components. The applicable aging effect is loss of material from corrosion. The inspection is performed in accordance with the National Fire Protection Association (NFPA) 25, Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems. Inspections are performed once every 5 years.

RAI 4.14-1, referring to Section 4.14.1 of Exhibit A of the LRA, asked Duke to indicate whether the 5-year visual examination of the elevated water storage tank covers 100 percent of both the interior and the exterior tank surfaces. If not, Duke was asked to indicate the approximate percentage of the total tank surfaces that will be examined and how the surfaces to be examined are selected. In response to the RAI, Duke stated that, as documented in Section 4.14 of Exhibit A of the LRA, the elevated water storage tank civil inspection is credited with managing the loss of material from the tank. The inspection covers 100 percent of both the interior and exterior tank surfaces. Note, however, that this inspection is credited in the LRA with managing the interior surfaces only. The inspection program for civil engineering structures and components is credited with managing the exterior of the elevated water storage tank. The inspection covers 100 percent of the external tank surface also. The response resolves the question.

RAI 4.14-2 asked Duke, with respect to the experience described in Section 4.14.2 of Exhibit A of the LRA, to indicate when water tank degradation was first observed at the ONS and to submit a summary of the tank inspections, including the types of degradation found and the corrective actions taken. Based on the results of past examinations, Duke was asked to discuss the rationale for concluding that the 5-year inspection frequency for the elevated water storage tank is reasonable and acceptable to effectively manage the aging effects on the tank. In response to the RAI, Duke stated that the ONS operating experience, discussed in Section 4.14.2 of Exhibit A of the LRA, demonstrates that the continued implementation of the elevated water storage tank civil inspection provides reasonable assurance that the aging effects will be managed so that the tank will continue to perform its intended function consistent with the CLB for the period of extended operation. Operating experience included a discussion of loss of material from the interior surface of the tank. Loss of material from corrosion was observed in 1986. The loss of material was characterized as a surface "rust" resulting from a coating deficiency. The rust was cleaned from the surface and the tank surface was recoated. Duke further stated that recent inspections did not identify any deficiencies in the coating or additional loss of material.

Duke elaborated that the most recent inspection of the tank exterior found no evidence of loss of material that would affect the ability of the elevated water storage tank to perform its intended functions. The dry surfaces of the tank interior had only a few areas of minor corrosion on the exterior surfaces of the tank bowl. The top layer of the paint was disbonding, but the underlying finish coat was well adhered. The wet surfaces of the tank interior had only some minor areas of corrosion at the intersection of the interior access tube and the roof of the tank. Where paint was disbonding or minor corrosion was identified, the surface has been cleaned and recoated. The above Duke response resolves the RAI.

The inspection frequency is consistent with the guidance provided in the NFPA Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems. Operating experience validates that the elevated water storage tank civil inspection provides reasonable assurance that the aging effects on the tank will be managed effectively so that the tank will continue to perform its intended functions consistent with the CLB for the period of extended operation.

RAI 4.14-3 asked Duke to describe the anchor connections provided between the conical bell of the tank and the foundation and to indicate whether the anchors, including the anchor chairs, are included within the scope of the elevated water storage tank AMP. Duke also was asked to discuss any anchor/anchor-chair degradation experienced to date and, as applicable, to discuss the disposition of this degradation found through implementation of the elevated water tank civil inspection. In its response, Duke stated that the anchor connections between the conical bell of the tank and the foundation are composed of a typical anchor chair with a top plate and two side stiffeners. Fourteen 2¼- in. anchor bolts pass through the chairs and into the foundation. Although the elevated water storage tank civil inspection includes inspection of the anchorage, the inspection program for civil engineering structures and components is credited with managing the aging effects of the exterior of the elevated water storage tank, as can be seen in Table 3.7–8 of Exhibit A of the LRA. Both inspections include examination of the anchorage, but the inspection program for civil engineering structures and components was chosen as the AMP based on preference. The inspection of the elevated water storage tank is included in the external inspections performed as part of the inspection program for civil engineering structures and components. No degradation of the anchor connection has been documented in previous inspection reports. The staff finds the above response acceptable.

Sludge has been found in the tank during these inspections and has been cleaned out. The sludge did not affect the ability of the tank to maintain inventory for the high-pressure service water system. Duke indicated that the foundation of the tank was examined and found in good condition with no cracking or deterioration. Duke indicated that the results of its past application of the elevated water storage tank civil inspection program have been excellent. The staff finds that the program should present a reasonable means for managing the aging effects of the tank; therefore, the program is acceptable.

The staff's evaluation of the inspection program for civil engineering structures and components is provided in Section 3.2.6 of this SER.

On the basis of the above discussions, the staff concludes that the applicant's AMPs for the yard structures are adequate and acceptable.

3.8.3.2.9 AMPs for Class 1 Component Supports

The applicant determined that the AMPs for license renewal covering Class 1 components are the boric acid wastage surveillance program, the ISI plan, the inspection program for civil engineering structures and components, and the OTSG upper lateral support inspection.

Section 2.4 of the LRA identifies the OTSG upper lateral supports as within scope. Section 3.4 of the LRA identifies cracking of the upper lateral support Lubrite pads as an applicable effect of aging.

The applicant has committed to a one-time inspection to assess the condition of the Lubrite pads prior to the period of extended operation. The results of this one-time inspection will be performed on a sample population that is applicable to all 30 Lubrite pads installed at the ONS (10 per unit). The staff finds that the scope of this one-time inspection is acceptable because the inspection will establish whether cracking of the Lubrite pads is an issue.

There are no preventive actions. If damaged pads are discovered, the inspection scope will be expanded and cracked Lubrite pads will be replaced. The staff finds that no preventive actions are required.

The parameters inspected are the visual surface condition of the Lubrite pads. The staff concludes that cracking of the Lubrite pads can be detected visually. Aging effects will be detected by determining visually whether the Lubrite pads are cracked.

There is no monitoring or trending of the cracking of Lubrite pads, and the staff agrees that none is required.

The acceptance criterion is no visible cracking of the Lubrite pads. The staff agrees that the acceptance criterion is valid.

There is no industry or ONS operating experience cited for the cracking of the Lubrite pads. The staff finds that the one-time inspection is appropriate because no industry or ONS operating experience exists.

The staff evaluation of the boric acid wastage surveillance program is addressed in Section 3.2.1 of this SER. The staff evaluation of the ISI plan is addressed in Section 3.2.5 of this SER. The staff evaluation of the inspection program for civil engineering structures and components is addressed in Section 3.2.6 of this SER.

GSI–173.A, "Spent Fuel Storage Pool: Operating Experience"

This issue deals with the potential for a sustained loss of spent fuel pool (SFP) cooling capability and the potential for a substantial loss of SFP coolant inventory. The staff evaluated the issue and concluded that no actions will be taken for operating plants. The results of the evaluation are documented in staff memoranda to the Commission dated July 26, 1996, and September 30, 1997. As indicated in NUREG–0933, the staff is pursuing regulatory improvement changes to Regulatory Guide 1.13, "Spent Fuel Storage Facility Design Basis," and NUREG–0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants." Thus, a license renewal applicant need not specifically address GSI–173.A. However, the applicant must address systems, structures, and components associated with the storage of new and spent fuel in accordance with the requirements in 10 CFR 54.21.

The applicant discussed GSI 173.A in Section 1.5.4 of Exhibit A of the LRA and concluded that this issue is resolved for the ONS. SFP cooling is addressed in Sections 2.5.6.1 and 3.5.6.1 of Exhibit A of the LRA and the staff evaluation is contained in Sections 2.2.3.4.1 and 3.6.1.1 of this SER. Spent fuel rack Boraflex is discussed in Section 5.7.2 of Exhibit A of the LRA and the staff evaluation is contained in Section 4.2.10 of this SER. The staff conclusions are contained in these SER sections.

3.8.3.3 Time-Limited Aging Analyses

The application identifies two TLAAs associated with structural components. The TLAAs deal with crane fatigue and Boraflex. The TLAAs are evaluated in Section 4 of this SER.

3.8.4 Conclusions

The staff has reviewed the information in Section 3.4.11; Section 3.7; Section 4.3.6; Section 4.4; Section 4.5, "Boric Acid Wastage Surveillance Program"; Section 4.6, "Chemical Control

Program"; Section 4.11; Section 4.12; Section 4.14; Section 4.15; Section 4.16, "Fire Protection Program"; Section 4.18, "ISI Plan"; Section 4.19, "Inspection Program for Civil Engineering Structures and Components"; Section 4.20; Section 4.28; and Section 4.29 of Exhibit A, "Technical Information," to the Duke LRA, and additional information submitted by the applicant in response to the staff's RAIs. On the basis of this review, the staff concludes that the applicant has demonstrated that the aging effects associated with the ONS structures (Section 3.7 of Exhibit A of the LRA) and component supports (Section 3.4.11 of Exhibit A of the LRA) will be adequately managed so there is reasonable assurance that these structures and component supports will perform their intended functions in accordance with the CLB during the period of extended operation.

3.9 Electrical Components

3.9.1 Introduction

Duke described its aging management review (AMR) of electrical components at the ONS in Section 3.6, "Aging Effects for Electrical Components" of Exhibit A of its license renewal application (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).

3.9.2 Summary of Technical Information in the Application

3.9.2.1 Electrical Components Subject to an Aging Management Review

In Section 3.2 of Exhibit A of the LRA, the applicant described the process to identify the applicable aging effects. In Section 3.6 of Exhibit A of the LRA, the applicant identified the applicable aging effects for electrical components. The process to determine the applicable aging effects on these electrical components is based on industry literature defining the component materials, the operating environment, and the operating stresses for each component subject to an AMR. The applicable aging effects are then validated by a review of industry and ONS operating experience.

The service environments identified for the ONS electrical components are thermal, radiation, and moisture. The bounding thermal environments for structures or areas are as follows:

Structure or Area	Bounding Temperature
Auxiliary buildings	150°F (65.6°C)

Intake structure	105°F (40.6°C)
Keowee structures	105°F (40.6°C)
Reactor buildings	175°F (79.4°C)
Standby shutdown facility	104°F (40.0°C)
Turbine buildings	105°F (40.6°C)
Yard structures	105°F (40.6°C)
All remaining site structures/areas	105°F (40.6°C)

The maximum 40-year normal operating dose and maximum 60-year normal operating dose (in rads) for structures are as follows:

Structure	Maximum 40-Year Normal Operating Dose (Rads)	Maximum 60-Year Normal Operating Dose (Rads)
Reactor buildings	3×10^7	4.5×10^7
Auxiliary buildings	1×10^6	1.5×10^6
Reactor buildings	3×10^5	4.5×10^5
Auxiliary buildings	1×10^5	1.5×10^5
Reactor buildings	3×10^4	4.5×10^4
Auxiliary buildings	1×10^3	1.5×10^4
Turbine buildings	1×10^3	1.5×10^3
Auxiliary buildings	1×10^2	1.5×10^2
Intake structure	Negligible	Negligible
Keowee structures	Negligible	Negligible
Standby shutdown facility	Negligible	Negligible
Yard structures	Negligible	Negligible
All remaining structures	Negligible	Negligible

Moisture from weather conditions such as dew, rain, fog, snow, and sleet can occur on exterior surfaces of structures and components located in yard areas. The ONS is not exposed to sulfate or chloride attack because it is not located near major industrial plants or seawater. Components located inside of structures may have short-term exposure to standing water from spills or normal system leakage that can result in corrosion, but these conditions are corrected through normal plant maintenance activities and are not considered in license renewal AMRs.

On the basis of the process that was used to identify the aging effects applicable to the ONS electrical components that are subjected to thermal, radiation, and moisture environments, the applicant has determined that the following electrical components are subject to an AMR:

- Buses
  - Isolated phase bus
  - Nonsegregated-phase bus
  - Segregated-phase bus
  - Switchyard bus

- Insulated cables and connections

- Insulators (high-voltage equipment)

- Transmission conductors

The applicant has identified the following intended functions for the above electrical components:

Component	Function
Buses, insulated cables & connections and transmission conductors	Provide electrical connection between two sections of an electrical circuit
Insulators (high-voltage equipment)	Insulate and support electrical conductor

3.9.2.2 Effects of Aging

The applicant evaluated the applicability of aging effects on electrical components by reviewing industry experience, Nuclear Regulatory Commission (NRC) generic communications, and ONS operating experience. The evaluation identified the following potential aging effects on electrical components:

Component	Effects
Phase bus	• Change in material properties • Loss of material
Switchyard bus	• Change in material properties because of surface oxidation
Insulated cables and connections	• Loss of material because of moisture • Change in material properties because of moisture, excessive heat, and radiation
Insulators	• Cracking • Loss of material due to wear • Surface contamination
Transmission conductors	• Loss of conductor strength

3.9.2.3 Aging Management Programs

On the basis of the review of industry information, NRC generic communications, and ONS operating experience, the applicant maintains that with the exception of insulated cables and connections, the aging effects identified above for the phase bus, the switchyard bus, insulators, and transmission conductors are not applicable and would not lead to a loss of intended function(s) for these components during the period of extended operation. Therefore, the applicant believes that no aging management programs (AMPs) are necessary for these electrical components.

3.9.2.3.1 Aging Management Program for Insulated Cables and Connections

Based on the inspection results and the NRC staff conclusions stated in the inspection report 50-269/99-12, 50-270/99-12, and 50-287/99-12 dated September 12, 1999, Duke agrees that there are adverse, localized environments, which may cause surface anomalies on the cable jacket such as embrittlement, discoloration, or cracking. Therefore, in letters dated December 17, 1999, and January 12, 2000, Duke has decided to manage the effects of aging in-scope, insulated cables and connections which could be affected by these adverse, localized environments. Duke has concluded that the Insulated Cables and Connections Aging Management Program will provide reasonable assurance that the license renewal intended functions of insulated cables and connections within the scope of license renewal will be maintained consistent with the current licensing basis through the period of extended operation.

3.9.2.4 Time-Limited Aging Analysis

The staff evaluation of the applicant's identification of time-limited aging analyses (TLAAs) is discussed separately in Section 4 of this SER.

3.9.3 Staff Evaluation

In accordance with 10 CFR 54.21(a)(3), the staff reviewed the information in Section 3.6 of Exhibit A of the LRA regarding the applicant's demonstration that aging effects will be adequately managed so that the intended function will be maintained consistent with the CLB for the period of extended operation for the electrical components. After completing the initial review, the staff issued a request for additional information (RAI) on November 25, 1998. The response was received on February 17, 1999, and revised responses were received on March 18, 1999. In addition, Duke responded on December 17, 1999, and January 12, 2000, to a NRC letter dated October 5, 1999, involving the aging management program for insulated cable and connections. The staff's October 5, 1999, letter added open item 3.9.3-1 for tracking purposes. Duke's December 17, 1999, and January 12, 2000, responses provides an aging management program for insulated cables and connections which is evaluated below. Based on Duke's addition of this aging management program, and the staff's evaluation below, the staff considers open item 3.9.3-1 described in the staff's October 5, 1999, letter closed.

3.9.3.1 Effects of Aging

As discussed in Section 3.9.2.2 of this SER, the applicant identified the following potential aging effects for license renewal by reviewing available industry literature: change in material properties, loss of material, cracking, surface contamination, and loss of conductor strength. The staff evaluated the applicant's identification of these potential aging effects for the phase bus, the switchyard bus, insulated cables and connections, insulators, and transmission conductors.

3.9.3.1.1 Aging Effects on Phase Bus Caused by Change in Material Properties and Loss of Material

The isolated-phase bus, nonsegregated-phase bus, and segregated-phase bus are subject to a change in material properties and a loss of material. Each phase bus is constructed of similar materials and exposed to similar service environments. The environmental conditions include temperatures of up to 105°F (40°C), radiation less than 1 x 10^3 rads, and exposure to moisture from all forms of precipitation. Self-heating contributes an increase in bus temperature of up to 72°F (40°C).

The phase bus materials include brass, bronze, copper, galvanized metals, grout, porcelain, and stainless steel, which are exposed to no significant aging effects in their service environment. However, phase bus materials such as aluminum and silicone caulk may be susceptible to changes in material properties, and steel may be susceptible to loss of material.

The No-Ox grease precludes oxidation of the aluminum surface at the bus connections. A change in material properties is not an applicable aging effect so long as the No-Ox grease is maintained. The grease is replaced routinely when maintenance is performed on the bus and no degradation of the grease has been noted during routine maintenance. Therefore, a change in the material properties of the aluminum bus connections is not an applicable aging effect when No-Ox grease is covering the material.

Silicone caulk is a silicone rubber that has a useful upper temperature of 392°F (200°C) and a projected service life of greater than 60 years. It is used to seal around the aluminum bus as it enters and exits a wall bushing that is used as a thermal barrier. Because of its high-temperature characteristics, silicon caulk will not change its material properties and is not subject to aging.

The steel hardware that is used on various parts of the bus enclosure assembly was factory coated to inhibit corrosion. No signs of corrosion have been observed after more than 20 years in its service environment. Therefore, loss of material for steel hardware is not an applicable aging effect that would lead to a loss of intended function for the phase bus for the period of extended operation.

The staff agrees with the applicant's assessment and the conclusion that on the basis of the review of industry information, NRC generic communications, and ONS operating experience, no aging effects are applicable for the phase bus and no AMP is necessary.

3.9.3.1.2 Aging Effects on Switchyard Bus Caused by Change in Material Properties

The switchyard bus is subject to a change in material properties from surface oxidation and the environmental conditions, including temperatures of up to 105°F (40.6°C), exposure to moisture from all forms of precipitation, and negligible radiation. An increase in temperature of up to 54°F (30°C) can result from self-heating.

All bus connections within the review boundaries are welded connections, and the only material used for the switchyard bus is aluminum. On the basis of the ambient environmental conditions the switchyard bus is exposed to at the ONS, no aging effects have been identified that could lead to a loss of intended function during the period of extended operation.

The staff agrees with the applicant's assessment and the conclusion that on the basis of the review of industry information, NRC generic communications, and ONS operating experience, no aging effects are applicable for the switchyard bus and no AMP is necessary.

3.9.3.1.3 Aging Effects on Cables and Connections Caused by Loss of Material and Change in Material Properties

Insulated cables and connections were evaluated in accordance with the Department of Energy "Aging Management Guideline for Commercial Nuclear Power Plants — Electrical Cable and Terminations." Also evaluated were the main subsystems within cables (conductors, insulation, shielding, tape wraps, jacketing, and drain wires) and all subcomponents associated with each type of connection.

Low-voltage connectors (<2-kV) are subject to loss of material from moisture. Medium-voltage cables (2-kV to 15-kV) are subject to changes in electrical properties from moisture, excessive heat, and radiation.

Moisture - Structures and areas where connectors may be exposed to moisture are the intake structure, the Keowee structure, and the yard structures. Connectors located in these areas are in enclosures and not subject to moisture or precipitation; therefore, aging effects related to moisture are not applicable to low-voltage connectors. 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 is 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 XLPE or high-molecular-weight polyethylene (HMWPE) insulation.

Radiation - Radiation-induced degradation in cable jacket and insulation materials produces changes in the organic material properties, including reduced elongation and changes in tensile strength. Visible indications of radiative aging may include embrittlement, cracking, discoloration, and swelling of the jacket and insulation. Table 3.6–5 of the LRA lists both the lowest threshold dose and the moderate-damage dose of gamma radiation for insulated cables and connections in use at the ONS.

Temperature - 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 with the time period fixed at 60 years was used by the ONS to determine the maximum continuous temperature to which the material can be exposed so that the material will not have reached the endpoint for elongation or tensile strength at the end of 60 years.

The staff agrees with the applicant's assessment that (1) medium voltage cables are subject to change in electrical properties from moisture, excessive heat, and radiation and (2) low-voltage connectors are subject to loss of material from moisture.

3.9.3.1.4 Aging Effects on Insulators Caused by Cracking, Loss of Material, and Surface Contamination

Electrical insulators at the ONS are installed outside and are exposed to environmental conditions that include temperatures up to 105°F (40.6°C), negligible radiation, and exposure to moisture from all forms of precipitation. Insulator materials include porcelain, various galvanized metals, and cement and are subject to cracking, loss of material from wear, and surface contamination.

Porcelain cracking from cement growth has only occurred in bad batches of insulators used in strain applications. The batches were improperly manufactured and inspections at the ONS did not identify any insulators from the known bad batches. Therefore, cracking is not an applicable aging effect for insulators at the ONS.

Insulators that are used for strain and suspension applications are subject to mechanical wear from movement caused by wind blowing the supported transmission conductor. Inspections of the ONS insulators have not identified any wear; therefore, loss of material is not an aging effect that will cause a loss of function of the insulators at the ONS.

Airborne materials such as dust, salt, and industrial effluents can contaminate insulator surfaces. A large buildup of contamination enables the conductor voltage to track along the surface more easily and can lead to insulator flashover. Because the ONS is located in a mountainous area where rain washes away any contamination that may have built up, contamination has not been a problem; therefore, surface contamination is not an applicable aging effect at the ONS for insulators and no AMP is required. The staff agrees with this assessment.

3.9.3.1.5 Aging Effects on Transmission Conductors Caused by Loss of Conductor Strength

Transmission conductors at the ONS are installed outside and are exposed to environmental conditions for yard structures that include temperatures up to 105°F (40.6°C), negligible radiation, and exposure to moisture from all forms of precipitation. In addition to the ambient environment, the applicant considers, as appropriate, the temperature rise of transmission conductors.

The transmission conductors are constructed of aluminum conductors that are steel reinforced (ACSR). Corrosion, which includes corrosion of the steel core and aluminum strand pitting, is the most prevalent mechanism contributing to loss of conductor strength. Based on testing of transmission conductors at Ontario Hydro electric, which showed a 30-percent loss of composite conductor strength of an 80-year-old ACSR conductor, and 50 years of operating experience at Duke on transmission systems, where no aging problems resulted in replacement of conductors, the applicant concluded that no applicable aging effects could affect the function of the transmission conductors for the period of extended operation. Therefore, no AMP is required. The staff agrees with this assessment.

3.9.3.2 Aging Management Programs for License Renewal

3.9.3.2.1 Aging Management Program for Insulated Cables and Connections

The staff focused its evaluation of the Duke aging management programs on the program elements rather than on the details of specific plant procedures. To determine whether the Duke aging management programs are adequate to manage the effects of aging so that the intended functions will be maintained consistent with the CLB for the period of extended operation, the staff evaluated the following 10 elements: (1) scope of program, (2) preventive actions, (3) parameters monitored or inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.

The application indicates that corrective actions, confirmation process, and administrative controls for license renewal are in accordance with the site-controlled quality assurance program pursuant to 10 CFR Part 50, Appendix B, and cover all structures and components subject to an AMR. The staff's evaluation of the applicant's quality assurance program is presented separately in Section 3.2.3 of this SER. Thus, these three elements will not be discussed further in this section.

Program Scope

By letter dated January 12, 2000, Duke described the Insulated Cables and Connections Aging Management Program which includes accessible and inaccessible insulated cables and connections within the scope of license renewal that are installed in adverse, localized environments in the Reactor Buildings, Auxiliary buildings, Turbine Buildings, Standby Shutdown Facility, Keowee, in conduit and direct-buried which could be subject to applicable aging effects from heat, radiation, or moisture. This program does not include insulated cables and connections that are in the Environmental Qualification (EQ) Program. The staff finds the scope of the program acceptable because it includes all non-EQ insulated cables and connections that are subject to potential adverse , localized environments of heat, radiation, and moisture that could result in applicable aging effects on these insulated cables and connections.

Preventive/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/Monitored
The applicant stated that it will perform visual inspections every 10-years of all adverse, localized environments containing accessible, in-scope, insulated cables and connections. EPRI TR- 109619, Guideline for the Management of Adverse Localized Equipment Environments will be use as guidance in implementing this program. In addition, water collection in cable manholes containing in-scope, medium-voltage cables will be monitored at a frequency adequate to prevent significant moisture exposure to the cables. The staff finds these techniques acceptable because they provide indications that can be visually monitored to preclude cable conductor insulation applicable aging effects for accessible cables.

For the inaccessible in-scope, medium-voltage cables, exposed to significant moisture and significant voltage, Duke commits to performing a test prior to the period of extended operation and to continue testing at least once every 10 years. The specific type of test will be determined prior to the initial test. The staff believes, based on current knowledge, that (if present) the degradation of this cabling would be due to a slow acting mechanism. Therefore, based on current knowledge, Duke's proposed test schedule is acceptable.

However, the staff is currently in the process of following up on an October 2, 1999, event at Davis Besse regarding a failure of a 4160 volt power cable for a component cooling water pump (see headquarters report dated December 3, 1999, H-99-0104). The staff will evaluate the root cause of this event, as well as the results of related tests and experience, to determine whether any further actions are necessary or whether to pursue this matter as a generic safety issue in accordance with the established regulatory process.

Detection of Aging Effects
As discussed above, the staff finds the inspection scope and inspection technique for both accessible and inaccessible in-scope cables and connections acceptable on the basis that the AMP is focused on detecting change in material properties of the conductor insulation which is the applicable aging effect when the cable is exposed to an adverse, localized environment due to heat, radiation, or moisture. The staff notes that corrective actions will be taken in

accordance with the ONS problem investigation process, which meets the requirements of 10 CFR Part 50, Appendix B for corrective actions.

Monitoring and Trending

AMP monitoring and trending actions as discussed above are focused on the applicable aging effect of change in material properties of the conductor insulation. The staff finds that these actions are necessary because they provide predictability of the extent of conductor insulation degradation for timely corrective or mitigative actions.

Acceptance Criteria

The applicant stated that for accessible insulated cables, no unacceptable, visual indications of cable 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 could lead to a premature failure of the component if the condition or situation is left unmanaged.

For inaccessible or direct-buried medium-voltage cables exposed to significant moisture and voltage, the test acceptance criteria will be defined by the specific type of test being performed. Significant moisture exposure is defined as periodic exposures to moisture that last more than a few days. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time.

When the acceptance criteria are not met, further investigation by Duke engineering will be performed and corrective actions may include testing, shielding, or otherwise changing the environment, relocating, or replacement of the affected cable. The staff finds the above acceptance criteria and corrective actions acceptable on the basis that they follow current industry standards which, when implemented, will ensure that the license renewal intended functions of the cables will be maintained consistent with the current licensing basis.

Operating Experience

The Oconee Insulated Cables and Connections Aging Management Program is a new program; thus, the applicant did not submit ONS-specific operating experience. However, industry experience supports both the need for the program and the attributes of the applicant's program. Thus, the staff finds that operating experience is satisfactorily incorporated into the development of this new program.

3.9.3.3 Time-Limited Aging Analysis

The evaluation of the applicant's identification of TLAAs is discussed separately in Section 4 of this SER.

3.9.4 Conclusions

The staff has reviewed the information in Sections 3.2 and 3.6 of Exhibit A of the LRA and the additional information provided by the applicant in response to the staff RAIs. On the basis of this review, the staff concludes that with the exception of insulated cables and connections, there are no applicable aging effects at the ONS for the phase bus, the switchyard bus insulators, and transmission conductors. Therefore, except for insulated cables and connections, no AMPs are necessary for these electrical components.

Regarding insulated cables and connections, the staff concludes that the applicant has demonstrated that aging effects will be adequately managed such that there is reasonable assurance that these components will perform their intended function in accordance with the CLB during the period of extended operation.

4 TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

Duke addressed the identification of time-limited aging analyses (TLAAs) and the process overview in Sections 5.1 and 5.2 of Exhibit A of its license renewal application (LRA). In addition, the applicant has provided a list of TLAAs (Table 5.2–1 of Exhibit A of the LRA) identified in the current licensing basis and has evaluated each TLAA.

4.1.1 Introduction

The staff has reviewed Sections 5.1 and 5.2 of the LRA to determine whether the applicant provided adequate information to meet the requirements stated in 10 CFR 54.21(c)(1).

4.1.2 Summary of Technical Information in the Application

The applicant has identified each TLAA of Table 5.2–1 of Exhibit A of the LRA, with its aging effect and its disposition, demonstrating, pursuant to 10 CFR 54.21(c)(1), that the analyses remain valid for the period of extended operation, that the analyses have been projected to the end of the period of operation, or that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation. The applicant identified the following as TLAAs:

- Fatigue analyses for the containment liner plate and penetration
- The loss of prestress in the containment post-tensioning system
- Fatigue and fracture mechanics analyses for inservice inspection (ISI) reportable indications in the reactor coolant system and Class 1 components
- Neutron embrittlement of the beltline region of the reactor pressure vessel (RPV), including analyses for pressurized thermal shock and Charpy upper-shelf energy reduction; also, intergranular separation in the heat-affected-zone of low-alloy steel under austenitic stainless steel cladding
- Flow-induced vibration, transient cycle count assumptions, and ductility reduction of fracture toughness for the reactor vessel internals
- Fatigue analysis of the reactor coolant pump flywheel
- Fatigue analyses for mechanical components
- Environmental qualification of electrical equipment
- Fatigue analysis of the polar crane
- Aging evaluation of Boraflex in the spent fuel rack

Pursuant to 10 CFR 50.21(c)(2), the applicant has stated that no exemptions granted under 10 CFR 50.12 have been identified that were based on a TLAA.

4.1.3 Staff Evaluation

In Sections 5.1 and 5.2 of Exhibit A of the LRA, the applicant describes the requirements for identifying and evaluating TLAAs and plant-specific exemptions that are based on TLAAs. Source documents evaluated by the applicant included Oconee Nuclear Station (ONS)-specific documents, such as the ONS licensing correspondence, the ONS updated final safety analysis report (UFSAR), Babcock and Wilcox (B&W) topical reports, and American Society of Mechanical Engineers (ASME) Section XI summary reports. Generic documents included the standard review plan; various codes and standards; Nuclear Regulatory Commission (NRC) bulletins, generic letters, and regulatory guides; and 10 CFR Part 50 and its appendices. In response to request for additional information (RAI) 5.4.1-1, the applicant indicated that leak-before-break (LBB) had been recently incorporated in the ONS licensing basis through the December 31, 1997, UFSAR update. As a consequence, the applicant identified LBB as an additional TLAA for the Oconee units. The information developed from these documents was reviewed by the staff to determine which analyses and calculations met the six criteria defining TLAAs in 10 CFR 54.3. For each identified TLAA, an evaluation was made in accordance with 10 CFR 54.21(c)(1).

4.1.4 Review Findings for Identification of Time-Limited Aging Analyses

The staff concludes that the applicant has provided a list of acceptable TLAAs as defined in 10 CFR 54.3 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 Evaluation of Time-Limited Aging Analyses

4.2.1 Containment Liner Plate and Penetrations

4.2.1.1 Introduction

The applicant described the process and results of its TLAA related to fatigue considerations for the containment liner plate and penetrations in Section 5.3.1 of Exhibit A of the LRA. The staff reviewed this section to determine whether the applicant provided adequate information to meet the requirements of 10 CFR 54.21(c) related to the TLAA for the containment liner plate and penetrations for the three ONS containments.

4.2.1.2 Summary of Technical Information in Application

The interior surface of the containment is lined with a welded steel plate to provide an essentially leak-tight barrier. At all penetrations, the liner plate is thickened to reduce stress concentrations. Design criteria are applied to the liner to assure that the specified leak rate is not exceeded under design-basis accident conditions. The applicant states that the following fatigue loads, as described in the ONS UFSAR, Section 3.8.1.5.3, were considered in the design of the liner plate and are considered to be TLAAs for the purposes of license renewal:

1. Thermal cycling due to annual outdoor temperature variations. The number of cycles for this loading is 40 cycles for the plant life of 40 years.

2. Thermal cycling due to variations of the reactor building interior temperature during the startup and shutdown of the reactor coolant system. The number of cycles for this loading is assumed to be 500 cycles.

3. Thermal cycling due to the loss-of-coolant accident (LOCA) is assumed to be one cycle.

4. Thermal load cycles in the piping systems are somewhat isolated from the liner plate penetrations by concentric sleeves between the pipe and the liner plate. The attachment sleeve is designed in accordance with ASME Section III considerations. All penetrations are reviewed for the number of cycles conservatively expected during the plant life.

The applicant evaluated each of the above TLAAs as follows:

For item 1, an increase in the number of thermal cycles due to annual outdoor temperature variations from 40 to 60 cycles is considered to be insignificant in comparison to the assumed 500 thermal cycles due to variations of containment interior temperature during heatup and cooldown of the reactor coolant system. This TLAA is considered to be valid for the period of extended operation because it is enveloped by item 2.

For item 2, the assumption of 500 thermal cycles due to startup and shutdown of the reactor coolant system, a more limiting number of thermal cycles is given in the ONS UFSAR, Section 5.2, for actual plant operation. The ONS UFSAR, Table 5.2, indicates a design limit of 360 heatup cycles and 360 cooldown cycles for the reactor coolant system. The projected number of cycles for each ONS unit through 60 years of operation has been determined to be less than the original 360 cycle design limits. This TLAA is considered to be valid for the period of extended operation because actual operating cycle values fall within the assumed 500 thermal cycles due to startup and shutdown of the reactor coolant system.

For item 3, the assumed value for thermal cycling due to the LOCA remains valid. No LOCAs have occurred and none are expected to occur. This TLAA is considered to be valid for the period of extended operation.

For item 4, the design of the containment penetrations has been reviewed. The design meets the general requirements of ASME Section III for thermal cycling. The only high-temperature lines penetrating the containment wall and liner plate are the feedwater and main steamlines. The design number of thermal load cycles in these two systems is bounded by the number of design heatup and cooldown cycles of the reactor coolant system. The projected number of cycles for each ONS unit through 60 years of operation has been determined to be less than these original design limits. Thus, on the basis of the existing fatigue analysis, this TLAA is considered to be valid for the period of extended operation.

Periodic Type A integrated leak rate tests are additional major sources of load changes. These Type A loads are considered within the set of design loads whose cumulative total was assumed to be 500 cycles. Seven Type A tests have been performed per unit to date (June 1998). The frequency of performing Type A tests has recently been revised to once every 10 years. Four more tests may be performed per unit through the period of extended operation. The additional load cycles on the liner due to Type A testing are considered to be insignificant.

For license renewal, the existing analyses addressing thermal fatigue of the containment liner plate and penetrations are considered to be valid for the period of extended operation.

4.2.1.3 Staff Evaluation

In Section 5.3.1 of the LRA, the applicant describes four cyclic-load considerations that could affect the results of the original fatigue load considerations during the period of extended operation. For the containment liner plate and the associated low-temperature penetrations in the containment wall, the applicant concludes that the fatigue load considerations extrapolated from 40 to 60 years in the TLAA would not have significant effects on these components, and that the existing fatigue load analysis is valid. The staff agrees with the applicant's logic in extending the existing fatigue load analysis to these components, except for the following confirmatory item.

In the applicant's initial response to RAI 3.3-6, Duke revised a paragraph related to the effects of periodic Type A leak rate tests on the TLAA. Duke stated that seven Type A tests have been performed, and based on the revised frequency of Type A tests (according to Option B of 10 CFR Part 50, Appendix J), four more tests will be performed. The applicant should note that the performance-based Option B allows the 10-year frequency if the results of the earlier tests have not shown problems. Also, the applicant may have to perform additional pressure tests after major modifications or repairs to the containment pressure boundary (e.g., steam generator replacement). The staff recognizes that these additional considerations will not affect the conclusions of the applicant's TLAA evaluation; however, for the completeness of the UFSAR supplement, the applicant should address these considerations in the analysis. This was identified as Confirmatory Item 4.2.1.3-1 in the June 16, 1999, ONS Safety Evaluatuion Report (SER). In Attachment 3 to the letter dated October 15, 1999, Duke proposed a change in the UFSAR supplement that specifies additional tests may be performed if major modifications or repairs are made to the containment pressure boundary. The staff finds the proposed change acceptable. Therefore Confirmatory Item 4.2.1.3-1 is closed.

For the high-temperature containment penetration lines (steam and feedwater lines), the applicant states that the thermal cycling analysis meets the general requirements of the ASME

Boiler and Pressure Vessel Code, Section III, "Nuclear Vessels." The applicant states that the design number of thermal load cycles for the high-temperature lines penetrating the containment wall is bounded by the number of design heatup and cooldown cycles of the reactor system. Initially, the number of design cycles for the 40-year period was 500, but this was subsequently reduced to 360 cycles in the LRA.

The ASME Section III Code requires that a fatigue analysis be performed for all cyclic loading conditions that may affect a given component, and that the cumulative usage factor (CUF) under these conditions be less than 1. In RAI 5.3.1-1, dated November 19, 1998, the staff asked Duke to submit the highest CUF for each piping containment penetration, and the basis, for 360 cycles. In a response dated February 8, 1999, Duke stated that actual CUFs are not available for the piping containment penetrations. The penetrations were qualified by ensuring that the number of plant heatups would be less than the number of cycles that would result in a CUF equal to 1. This number was determined to be 10,000. No basis for this number was given. The basis for this number was included as part of Open Item 4.2.1.3-1, as discussed below.

With regard to the basis for the design cycles, in its response to RAI 5.3.1-1, Duke referred to Table 5.2 of the ONS UFSAR as the basis for the 360 design cycles. However, the table also shows other normal operating design transients, such as power change cycles, power loading cycles, and 10% load increase and decrease cycles. The fatigue evaluation thus did not appear to be complete and in conformance with the design basis for the containment piping penetrations. The staff requested that the applicant justify why the thermal expansion of the reactor coolant system (RCS) under these additional cycling conditions, and its effect on the steam and feedwater lines, should not be included in the fatigue assessment of the containment piping penetrations. In the UFSAR supplement, the applicant should discuss the cumulative effects of all the possible cycles in the fatigue analysis for the containment liner and penetrations for the extended period of operation. This was identified as Open Item 4.2.1.3-1 in the June 16, 1999, ONS SER.

In a letter dated October 15, 1999, Duke presented its response to this item. In its response, Duke demonstrated how the cumulative effects of all of the possible cycles in the fatigue analysis were considered for the period of extended operation. Duke concluded that the TLAA for the containment liner plate and penetration fatigue is resolved in accordance with 10 CFR 54.21(c)(1)(i) as the analysis remains valid for the period of extended operation and is summarized below:

The projected number of cycles for each ONS unit through 60 years of continued operation are bounded by the cycles listed in Table 5-2 of the ONS UFSAR. For example, the units are designed for 18,000 cycles of Transients 3 (8% to 100%). For the main feedwater or main steam systems to cycles 18,000 times in 60 years, the reactor would need to cycle from 8% power to 100% power 300 times a year or almost once a day. The RCS and associated systems would need to operate well outside current practice to accumulate one cycle of 8% power to 100% power every day. Therefore, as provided for in 10 CFR Part 54, the time-limited aging analysis of the containment liner plate and penetration fatigue is resolved in accordance with 10 CFR 54.21(c)(1)(i) by demonstrating that the analysis remains valid for the period of extended operation.

The staff considers this response acceptable; therefore, Open Item 4.2.1.3-1 is closed.

4.2.1.4 Review Findings for the Containment Liner Plate and Penetration Fatigue Analysis

The applicant described its TLAA of the containment liner and penetrations in Section 5.3.1 of Exhibit A of the LRA. The staff has reviewed this section of the LRA to determine whether, as required by 10 CFR 54.21(c)(1)(ii), the applicant has appropriately projected the TLAA for the containment liner and penetrations to the end of the period of extended operation. One open item and one confirmatory item related to the TLAA are resolved. Thus, on the basis of this review, the staff concludes that the applicant has demonstrated that the time-dependent effects of the cyclic loads on the containment liner and penetrations will not adversely affect their intended functions in accordance with the CLB during the period of extended operation.

4.2.2 Containment Post-Tensioning System

4.2.2.1 Introduction

In Section 5.3.2 of Exhibit A of the LRA, the applicant described the process and results of the TLAA related to the adequacy of prestressing forces in the containment post-tensioning tendons during the period of extended operation. The staff reviewed this section to determine whether the licensee provided adequate information to meet the requirements of 10 CFR 54.21(c) related to the TLAA for the prestressing force in the containment post-tensioning tendons in the ONS containments.

4.2.2.2 Summary of Technical Information in the Application

The applicant discussed the parameters and essential elements of the TLAA as follows:

- Loss of prestress in the post-tensioning system is due to material strain occurring under constant stress. Loss of prestress over time is accounted for in the design and is a TLAA requiring review for license renewal.

- In accordance with American Concrete Institute (ACI) 318–63, "Building Code Requirements for Reinforced Concrete," the design of the ONS containment post-tensioning system provides for prestress losses caused by (1) elastic shortening of concrete, (2) creep of concrete, (3) shrinkage of concrete, (4) relaxation of prestressing steel stress, and (5) frictional loss due to curvature in the tendons and contact with tendon conduit.

By assuming an appropriate initial stress from tensile loading and using appropriate prestress loss parameters, the magnitude of the design losses and the final effective prestress forces at the end of 40 years for dome, vertical, and hoop tendons were calculated at the time of initial licensing. This analysis is summarized in the ONS UFSAR, Section 3.8.1.5.2.

In 1996, the applicant provided a description of the methodology for determining the most accurate minimum required lift-off force for each tendon group for NRC review. On the basis of the results of the evaluation of the submitted information and commitments made by the applicant, the NRC staff had determined that the integrity of the ONS containment was adequate to support continued operation.

Containment post-tensioning system surveillances will be performed in accordance with ONS Improved Technical Specification SR 3.6.1.2. Acceptance criteria for tendon surveillance are given in terms of prescribed lower limits (PLLs) and minimum required values (MRVs). The ONS UFSAR Selected Licensee Commitment (SLC) 16.6.2 provides the required PLLs and MRVs in Appendix 16.6–2, Figures 1, 2, and 3. These figures contain the dome, hoop and vertical tendon prescribed lower limits and minimum required values for all three ONS units. The figures have been developed using the guidance contained in RG 1.35. Each PLL line has been extended to 60 years of plant operation and remains above the MRVs for all three tendon groups.

For license renewal, the existing analysis addressing loss of prestress in the containment post-tensioning system is considered to be valid for the period of extended operation. In addition, continuation of the current surveillance program provides reasonable assurance that the post-tensioning system will remain capable of performing its intended function.

4.2.2.3 Staff Evaluation

In Section 5.3.2 of Exhibit A of the LRA, the applicant describes the TLAA for the containment post-tensioning system at the ONS. TLAA for a post-tensioning system should have the following basic attributes:

- Calculated PLL prestressing force for each group of prestressing tendons. The PLL is estimated from the initial prestressing force minus the estimated immediate losses (anchor slip and elastic shortening of the structure) and minus time-dependent losses. The PLL is graphically represented on a semi-log paper with "time" on logscale. During each inspection, the measured prestressing forces in the sampled tendons are compared against the PLL, individually and in groups.

- Calculation of the MRV prestressing force based on the designated load combination, including the loss-of-coolant-generated internal pressure load on the containment.

- The MRV is generally the calculated value of the PLL 40 years after the installation of tendons, with margin. For the period of extended operation, the PLL must be extended to 60 years, and the applicant must demonstrate that the trend of measured prestressing forces during the extended period will stay above the extended PLL, or must have a systematic plan for retensioning selected tendons so the trend lines during the extended period will stay above the PLLs for each group of tendons.

In Figures 1, 2, and 3 of Appendix 16.6–2 to Chapter 16 of the UFSAR Supplement for License Renewal, the applicant shows the PLL lines and MRVs for the 60-year period for each group of tendons in the ONS containments. However, the applicant does not show the trend lines that would demonstrate the adequacy of the existing prestressing forces in the containment tendons for the period of extended operation. This was identified as Open Item 4.2.2.3-1 in the June 16, 1999, SER.

In response to Open Item 4.2.2.3-1, by letter dated December 17, 1999, the applicant fully addressed the item. Instead of demonstrating that the present trend in prestressing forces in Oconee containments is sufficient to assure their adequacy up to the end of the extended period of operation, the applicant opted for preparing an aging management program (AMP) related to the TLAA of prestressing forces in accordance with 10 CFR 54.21(c)(1)(iii) as discussed below:

Purpose – The purpose of the "Post-Tensioning System Loss of Prestress Aging Management Program" is to identify and correct degradation of the post-tensioning system prior to a loss of prestress that does not meet the required minimum value.

Scope – The scope of the "Post-Tensioning System Loss of Prestress Aging Management Program" covers the loss of prestress of post-tensioning systems of concrete containments.

Aging Effects – Loss of prestress of the post-tensioning system.

Method – Tendon prestress force and elongation are required to be measured to evaluate the prestressing force of the system. Prestress forces are trended in accordance with the requirements of 10 CFR 50.55a(b)(2)(ix)(B).

Sample Size – Not applicable for an existing program. Note: the sample size is specified in IWL-2520.

Industry Codes or Standard – ASME Code Section XI, Subsection IWL provides requirements for inservice inspection, trending, and repair or replacement activities of the post-tensioning systems of concrete containments.

Frequency – The frequency of inspection of the post-tensioning system is specified in the ONS Containment Inservice Inspection Plan which is addressed in Section 4.8 of Exhibit A of the Application.

Acceptance Criteria or Standard – Acceptance standards for the post-tensioning system are specified in ONS UFSAR, Chapter 16, SLC 16.6.2. ONS UFSAR, Chapter 16, SLC 16.6.2 contains the minimum required value and prescribed lower limit for each group of tendons.

Corrective Action – Where tendon forces fall below the acceptance standards, corrective actions may be include retensioning, replacement of selected tensions with new tendons, or reanalysis. Specific corrective actions will be taken in accordance with the Duke Quality Assurance Program.

Administrative Controls – The ONS "Post-Tensioning System Loss of Prestress Aging Management Program" which is an activity within the Containment Inservice Inspection Plan, is implemented by procedures that are developed and maintained in accordance with the Duke Quality Assurance Program.

Regulatory Basis – The ONS "Post-Tensioning System Loss of Prestress Aging Management Program" which is an activity within the Containment Inservice Inspection Plan, will implement the requirements of 10 CFR 50.55a (61 Federal Register 41303, dated August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants."

While the program elements did not match the NRC desired program elements, they addressed the technical areas adequately. With the inclusion of this AMP during the extended period of operation, the staff considers Open Item 4.2.2.3-1 resolved.

Thus, on the basis of this review, the staff concludes that with the implementation of the AMP specifically developed to address the TLAA for monitoring the adequacy of prestressing force in Oconee containments, the time-dependent effects of prestress loss will not adversely affect the intended functions in accordance with the CLB during the period of extended operation.

4.2.2.4 Review Findings for the Containment Post-Tensioning System

The applicant described its TLAA of the containment post-tensioning tendon forces in Section 5.3.2 of Exhibit A of the LRA. The staff reviewed this section of the LRA, the associated UFSAR supplements, and the AMP described above; and determined that the applicant has addressed this TLAA as required by 10 CFR 54.21(c)(1)(iii). As a result of this review, including closure of Open Item in 4.2.2.3-1, the staff has concluded that this TLAA is acceptable.

4.2.3 Fatigue Analysis of Reactor Coolant System

4.2.3.1 Introduction

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 in the ONS RCS and, consequently, fatigue is part of the current licensing basis (CLB) for the ONS. The applicant identified fatigue and flaw growth evaluations as TLAAs for the piping and components of the RCS. The staff reviewed Section 5.4.1 of the LRA, which discusses thermal fatigue and flaw growth of the RCS piping and components.

4.2.3.2 Summary of Technical Information in the Application

The applicant discusses design criteria for thermal fatigue used for the RCS piping and components in Section 5.4.1.1 of Exhibit A of the LRA. B&W designed the main RCS components and piping, and Bechtel designed piping attached to the RCS loop. The B&W scope of supply includes all major components in the RCS and the associated piping. Components were designed to ASME Code Section III Class 1 criteria and the piping to United States of America Standards (USAS) B31.7 Class I criteria. The piping and components, except for the surge line, were evaluated using the design transient cycles specified in Table 5–2 of the ONS UFSAR. The surge line was evaluated using the design transient cycles specified in Table 5–23 of the UFSAR.

The Bechtel scope of supply for the RCS included the following attached piping:

- Low-pressure injection (LPI)/core flood piping
- Pressurizer spray bypass line/auxiliary spray line
- High-pressure injection (HPI)—emergency injection piping
- HPI—normal makeup piping
- LPI—decay heat drop line (including dump-to-sump)
- HPI letdown piping
- All RCS loop drains

The applicant also discusses actions it has taken in response to NRC Bulletin (BL) 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," and its supplements, and BL 88–11, "Pressurizer Surge Line Thermal Stratification." NRC BL 88–08 involves the potential for temperature stratification or temperature oscillations in unisolable sections of piping attached to the RCS. NRC BL 88-11 involves the potential temperature stratification and thermal striping in the pressurizer surge line. These events were not considered in the original design of the piping. The applicant performed subsequent evaluations to address the bulletins.

The applicant discusses flaw growth acceptance for the RCS components at the ONS in Section 5.4.1.2 of Exhibit A of the LRA. As described in the LRA, ISI at the ONS, in accordance with ASME Section XI ISI requirements, has led to the identification of crack-like indications, primarily in welds. The LRA states that fracture mechanics analyses used for flaw acceptance through the current license period have been reviewed for acceptability for the period of extended operation.

The applicant discusses its fatigue management program (FMP) to manage the fatigue and flaw growth of the RCS components and piping in Section 5.4.1.3 of Exhibit A of the LRA. The applicant's FMP tracks plant thermal cycles for those components evaluated using explicit design cycle assumptions. The applicant identified the scope of the program as follows:

- RCS components (including piping connected to the RCS falling under the purview of Office of NRC Inspection and Enforcement (IE) BLs 88–11 and 88–08)
- Components within the ONS ISI program that contain flaws detected during ISI that exceeded acceptance standards, but were shown acceptable by analysis

4.2.3.3 Staff Evaluation

As discussed in the previous section, components of the RCS were designed to codes that contained explicit criteria for the fatigue analysis. Consequently, the applicant identified the fatigue analyses and the flaw growth evaluations of RCS components as TLAAs. The staff reviewed the applicant's evaluation of RCS components for compliance with the provisions of 10 CFR 54.21(c)(1).

The specific design criterion for Class 1 components involves calculating the CUF. The fatigue damage caused by each thermal or pressure transient depends on the magnitude of the stresses caused in the component by the transient. The CUF sums the fatigue resulting from each transient. The design criterion requires that the CUF not exceed 1.0. The applicant indicated that the transients used to evaluate the RCS components are listed in Table 5–2 of the ONS UFSAR, with the exception of the pressurizer surge line, which is covered by Table 5–23 of the UFSAR.

The applicant indicated that plant operating thermal transient data were used to project when plant operation would cause the number of cycles specified in the UFSAR to be exceeded. According to the applicant, locations such as the reactor vessel studs, the pressurizer spray line for Unit 3, and the emergency feedwater (EFW) system nozzle for Unit 3 required further evaluation. The applicant further indicated that the transients would be monitored by the ONS thermal FMP. The staff, in RAI 5.4.1-2 issued November 20, 1998, asked Duke to describe the planned evaluation of these components and provide a schedule for the completion of these evaluations. In a response issued February 17, 1999, Duke indicated that the RPV studs were reevaluated to remove a conservative assumption regarding the number of cycles assumed in the evaluation. The Unit 3 pressurizer spray and EFW nozzles were reanalyzed because the analyses were not consistent with the Unit 1 and 2 analyses. According to the applicant, the evaluations of the RPV studs and the Unit 3 pressurizer spray line were complete, and the EFW nozzle analysis was expected to be complete by August 1, 1999. Completion of the EFW nozzle analysis and modification of the FMP as appropriate was identified as part of Confirmatory Item 4.2.3-1 in the June 16, 1999, SER. In a letter dated October 15, 1999, Duke indicated that the EFW nozzle analysis was completed and the revised cycle count assumptions had been incorporated into the basis of the ONS thermal FMP. Therefore, the staff considers this part of Confirmatory Item 4.2.3-1 closed.

According to the applicant, the attached piping was originally designed to USAS B31.7, Class I standards, except for the piping analysis, which was done to Class II standards. However, the ONS UFSAR indicates that the attached piping to the first isolation valve is designed to Class I standards. The staff raised a concern regarding the lack of a Class I analysis of the attached piping during a 1994 site visit. This concern was formally documented in a letter dated April 27, 1995. In the response to the staff concern dated June 26, 1995, Duke committed to completing a Class I analysis of the attached piping to the first isolation valve by August 31, 1999. Duke also indicated that these components would be added to the FMP. Completion of the analysis of these lines and modification of the FMP as appropriate was identified as part of Confirmatory Item 4.2.3-1 in the June 16, 1999, SER. In a letter dated October 15, 1999, Duke indicated that the Class 1 analysis of each branch line has been completed and that the cycle count assumptions had been incorporated into the basis of the ONS thermal FMP. Therefore, the staff considers this part of Confirmatory Item 4.2.3-1 closed.

The applicant discussed its actions to resolve NRC BL 88–11 in Section 5.4.1.1.4 of Exhibit A of the LRA. In NRC BL 88-11 the staff requested that licensees establish and implement a program to determine the impact of thermal stratification on pressurizer surge line integrity. The applicant indicated that the original design analysis did not include stratified-flow loading conditions. A bounding analysis of the surge line was performed as part of a B&W Owners Group effort. The applicant updated the fatigue analysis of the ONS surge line. The surge line transients from the updated analysis are included in UFSAR Table 5–23. The applicant indicates that the transients will be managed by the ONS FMP.

The applicant discussed its actions to resolve NRC BL 88-08 in Section 5.4.1.1.5 of Exhibit A of the LRA. In NRC BL 88-08, the staff requested that licensees review their RCS designs to identify any connected, unisolable sections of pipe that could be subjected to temperature distributions that would result in unacceptable stresses. In response to the bulletin, the applicant identified the emergency injection lines of the HPI system as the only lines potentially susceptible to unacceptable stresses. Duke described its actions in response to the bulletin in a December 29, 1989, letter to the NRC. As a result of a subsequent leak in the normal injection line, Duke committed to submit a revised response to NRC BL 88-08 by July 1, 2000. Completion of this evaluation and modification of the FMP as appropriate was identified as part of Confirmatory Item 4.2.3-1 in the June 16, 1999, SER. By letter dated October 15, 1999, the applicant indicated that the activity associated with NRC BL 88–08 is intended to confirm the validity of the existing analyses by comparing actual thermal data obtained at Units 2 and 3 with the values used in the existing analyses. The applicant further indicated that the commitment to obtain this thermal data is captured within the ONS commitment management program. On the basis of the applicant's formal management of the commitment to obtain the confirmatory thermal data, the staff considers all parts of Confirmatory Item 4.2.3-1 closed.

The applicant indicated that locations evaluated using the flaw growth procedures of ASME Section XI were evaluated for the period of extended operation. The application identified several flaw locations that had not been demonstrated as acceptable for the number of controlling design basis transients. This was identified as Open Item 4.2.3-1.

Since the submittal of the application, the applicant has completed evaluations that have demonstrated the acceptability of these flaw locations, except for the pressurizer upper head to shell weld of Unit 2, the control rod drive mechanism (CRDM) tube housings, and the Unit 1 steam generator at the upper head to tubesheet region. The CRDMs and the steam generators are scheduled for replacement during the initial license, and hence do not require evaluation. If the pressurizer weld location cannot be demonstrated to be acceptable, then the number of cycles to be managed by the Oconee FMP will be revised to reflect an acceptable condition. This closes Open Item 4.2.3-1.

The LBB evaluation for the ONS RCS main coolant loop piping is described in BAW-1847, Revision 1, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS." This report was approved by the NRC staff. The applicant indicated that the TLAA in BAW–1847 involves fatigue flaw growth and a qualitative assessment of thermal aging of cast austenitic stainless steel (CASS) reactor coolant pump inlet and exit nozzles.

The applicant argued that, since recently the NRC position on LBB had eliminated the requirement to perform a fatigue flaw growth analysis, the flaw growth evaluation in BAW–1847 is no longer required. However, the staff considers the flaw growth evaluation contained in BAW–1847 part of the current licensing basis and, therefore, it is the staff's position that the flaw growth evaluation should be evaluated as a TLAA. In a followup discussion, the applicant indicated that the fatigue flaw growth evaluations are based on transient definitions defined by the RCS specification. These transients are being monitored by the ONS FMP. The staff concludes that the ONS FMP provides an acceptable method for managing the fatigue flaw growth aspect of the LBB evaluation.

The second aspect of the LBB evaluation involves aging of the CASS material. The applicant indicated that the susceptibility of the RCS to thermal aging was qualitatively assessed in BAW–1847. The values of the fracture toughness for aged CASS were assumed to be bounded by the ferritic piping and ferritic weldments. However, more recent data published in NUREG CR–6177, "Assessment of Thermal Embrittlement of Cast Stainless Steels," indicate that prolonged exposure of CASS to reactor coolant operating temperatures can lead to reduction of fracture toughness by thermal embrittlement. To address this concern, the applicant performed a flaw stability analysis using the lowerbound CASS fracture toughness curves from NUREG CR–6177 to demonstrate the acceptability of the LBB of the RCS for the extended period of operation. The staff concludes that the applicant's LBB assessment of RCS CASS materials is an acceptable TLAA for the period of extended operation.

The applicant relies on the ONS FMP to track plant thermal cycles for those RCS components that contain design features that have explicit design basis transient assumptions. In RAI 5.4.1-5 issued November 24, 1998, the staff asked Duke to supply a description of the FMP. The scope of the program is described in the previous section of this SER. The FMP requires the logging of design transients when they occur. According to Duke, the number of cycles of each significant transient is compared to the number of cycles evaluated in the fatigue analysis. The staff requested further clarification regarding this procedure during a phone call on March 18, 1999. In a supplemental response dated March 29, 1999, Duke submitted an additional discussion of the program. Table 1 of the supplemental response contains a list of the cycles tracked by the program. The number of cycles logged is compared to the number assumed in the analysis. In addition, significant parameters such as temperature limits and rates of temperature change are logged for comparison with the analysis. On the basis of this comparison, Duke verifies that the significant parameters used in the analysis and number of cycles assumed in the analysis have not been exceeded.

The applicant indicated that, if the parameters assumed in the analysis were exceeded, the Duke Problem Identification Program (PIP) would be used to record the problem and determine the appropriate corrective actions. The applicant would have to evaluate the event to determine whether the design criteria are exceeded to determine appropriate corrective action. The applicant also indicated that corrective actions would be initiated prior to exceeding the number of cycles used in the analysis. The corrective actions could involve reanalysis, transient reclassification, more sophisticated monitoring, repair, and replacement. The applicant also indicated that all RCS components associated with the parameter or cycle limit that may be exceeded would be reevaluated.

The applicant's FMP tracks transients and cycles of RCS components, as described above, that have explicit design basis transient cycles to assure 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, "Fatigue Evaluation of Metal Components for 60-year Plant Life," to address license renewal. The resolution of GSI–166 for the 40-year design life relied, in part, on conservatism in the existing CLB analyses. This conservatism included the number and magnitude of the cyclic loads postulated in the initial component design. A detailed discussion of the GSI–166 evaluation is contained in SECY 95–245, "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 FMP 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, a recommendation 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. Even though the EPRI reports do not contain analyses of ONS components, the staff technical concerns regarding application of the EPRI evaluation methodology, including the assessment of the new Argonne National Laboratory (ANL) data correlations, are relevant to the resolution of GSI–190 at ONS. 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.

Since GSI–190 has not been resolved, the staff requested, in RAI 1.5.5-1, that Duke discuss how it satisfies the relevant portion of paragraph 54.29 of the license renewal rule as discussed in the statement of considerations (SOC) (60 FR 22484, May 8, 1995) in the absence of the staff's endorsement of EPRI Report TR–105759. Duke did not provide a technical rationale addressing the adequacy of components in the reactor coolant pump (RCP) boundary considering environmental fatigue effects pending the resolution of GSI–190. In its response to the RAI, Duke stated that the concerns of GSI–190 are not directly related to the ONS thermal fatigue design and licensing basis. Duke further indicated that the LRA contains its technical rationale for concluding that the effects of thermal fatigue will be adequately managed for the period of extended operation or until GSI–190 is resolved. On this basis, Duke concluded that the relevant portions of 54.29 of the license renewal rule as discussed in the SOC (60 FR 22484, May 8, 1995) are met by the ONS FMP. The staff does not agree with the applicant's reasoning. As discussed above, the staff assessment for GSI–166 found sufficient conservatism in the CLB for the 40-year design life. However, this conclusion could not be extrapolated beyond the current facility design life. As a consequence, the staff recommended that a sample of components with high usage factors be evaluated using the latest available environmental fatigue data for any proposed period of extended operation. The staff also initiated GSI–190 to further evaluate this issue for license renewal.

On the basis of the preceding discussion, the staff concluded that the applicant's TLAA of the RCS was not adequate to address the fatigue concerns for operation beyond the current design life of 40 years. The staff indicated that the applicant must either develop an aging management program that incorporates a plant-specific resolution of GSI–190 or submit a technical rationale that demonstrates that the CLB will be maintained until some later point in time in the period of extended operation, at which point one or more reasonable options would be available to adequately manage the effects of aging. The staff identified resolution of the concern regarding environmental effects on the fatigue life of components as Open Item 4.2.3-2.

In an October 15, 1999, response to Open Item 4.2.3-2, Duke proposed two alternatives to address GSI–190. The proposed alternatives are to:

- Adopt the NRC's eventual generic resolution of GSI–190
- Implement a plant-specific management program

Duke described the proposed plant-specific management program in its letter. As described previously, the ONS FMP tracks the number of design transient cycles specified in the UFSAR. Duke proposes to apply an environmental penalty factor to the allowable number of design transient cycles at selected locations. The locations Duke selected are the same locations selected by the staff and evaluated in NUREG/CR–6260 as a representative sample of safety-significant locations with high fatigue usage. These locations are:

- Reactor vessel shell lower head
- Reactor vessel inlet and outlet nozzles
- Pressurizer surge line
- Makeup/HPI nozzle
- Reactor vessel core flood nozzle
- Decay heat removal system Class 1 piping

The staff finds these locations will provide an acceptable sample for assessing environmental effects on the fatigue life of components at the ONS.

The components associated with the reactor vessel (vessel shell, inlet and outlet nozzles, and core flood nozzle) have been evaluated in B&W Owners Group (B&WOG) topical report BAW–2251A. In its April 26, 1999, SER of BAW–2251A, the staff concluded that environmental effects on the fatigue life of reactor vessel components had been adequately addressed for license renewal. Therefore, the applicant's plant-specific program will address the remaining three locations. These locations are austenitic stainless steel components.

The applicant will assess the effect of the environment using statistical correlations developed by ANL and published in NUREG CR–5704. The applicant will use the ANL statistical correlations to calculate an effective environmental penalty factor to account for the reduction in fatigue life due to the reactor water environment. This factor would then be used to adjust fatigue usage factors calculated for the applicable transients. In applying this approach, the applicant has taken some credit for moderate environmental effects in the original design fatigue curves by calculating an effective environmental factor. A discussion of the credit available in the design fatigue curves to accommodate environmental effects is contained in the enclosure to the staff's August 6, 1999, letter. In that enclosure, the staff indicated that a factor of 1.5 on life may be used to account for moderate environments in the ASME fatigue curves for stainless steel components. The applicant proposed the factor of 1.5 for its evaluation of these components.

The staff considers the applicant's proposed program an acceptable plant-specific approach for the resolution of GSI–190. The applicant's proposed program is also consistent with the staff closeout of GSI-190 discussed in the December 26, 1999, memorandum from A. Thadani to W. Travers, "Closeout of Generic Safety Issue 190, 'Fatigue Evaluation of Metal Components For 60-Year Plant Life'." The staff concludes that the FMP, modified to account for the reactor water environment as described above, presents an acceptable method for managing fatigue for the period of extended operation and satisfies the requirements of 10 CFR 54.21(c)(iii). Therefore, Open Item 4.2.3-2 is closed.

4.2.3.4 Review Findings for Fatigue Analysis of the Reactor Coolant System

The applicant uses the ONS FMP to track the fatigue usage and flaw growth of components in the RCS. The FMP tracks the occurrences of the significant design cycles to ensure that the number of cycles and the significant parameters assumed in the analysis are not exceeded. With the resolution of the open and confirmatory items identified in Section 4.2.3.3 of this SER , the staff concludes that the applicant's TLAA for the RCS components, which relies on the FMP to track the design cycles, satisfies the requirements of 10 CFR 54.21(c)(1)(iii) by managing fatigue during the period of extended operation.

4.2.4 Reactor Neutron Embrittlement and Underclad Cracking

4.2.4.1 Introduction

The TLAAs for pressurized thermal shock, Charpy upper shelf energy, and intergranular separations under vessel weld cladding are covered below.

4.2.4.2 Summary of Technical Information in the Application

The TLAAs evaluated in the ONS LRA for the reactor vessel include:

- Analyses and calculations performed to show compliance with NRC regulations (10 CFR 50.60 and 50.61) concerning reduced fracture toughness of reactor vessel materials, pressurized thermal shock (PTS), and reduced Charpy upper shelf energy (USE)

- Growth of intergranular separations in low-alloy steel forging heat-affected zones under stainless steel weld deposit cladding (underclad cracking)

On February 17, 1999, Duke issued its response to the staff's RAI 5.1-1 (issued December 3, 1998). The response stated that in order to provide reasonable assurance that all the ONS TLAAs have been identified, Duke conducted multiple searches of multiple source documents. ONS-specific source documents that were reviewed include the ONS licensing correspondence file, the ONS UFSAR, referenced BAW topical reports, and ASME Section XI summary reports. Additional assurance of completeness was obtained by reviewing several generic source documents such as the standard review plan, various codes and standards, certain NRC generic regulatory compliance documents, and 10 CFR Part 50. The information developed from these documents determined which calculations and analyses met all six criteria of 10 CFR 54.3.

4.2.4.3 Staff Evaluation

4.2.4.3.1 Reduction of Fracture Toughness

The regulations governing reactor vessel integrity are in 10 CFR Part 50:

- Section 50.60 requires all light-water reactors to meet the fracture toughness, pressure-temperature (P-T) limits, and material surveillance program requirements for the reactor coolant boundary as set forth in Appendices G and H to 10 CFR Part 50.
- Section 50.61 contains fracture toughness requirements for protection against pressurized thermal shock events.

RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," describes general procedures acceptable to the staff for calculating the effects of neutron radiation embrittlement of the low-alloy steels currently used for light-water-cooled reactor vessels. The fracture toughness of the reactor coolant pressure boundary required by 10 CFR Part 50 is necessary to set adequate margins of safety during any condition of normal plant operation, including anticipated operational occurrences and system hydrostatic tests.

10 CFR Part 50, Appendix G requires that heatup and cooldown of the reactor pressure vessel be accomplished within P-T limits. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. As the reactor pressure vessel embrittles and its fracture toughness is reduced, the allowable pressure is reduced. Operation of the reactor coolant system is also limited by the net positive suction curves for the reactor coolant pumps. These curves specify the minimum pressure required to operate the reactor coolant pumps. Therefore, to heat-up and cool-down, the reactor coolant temperature and pressure must be maintained within an operating window established between the Appendix G P-T limits and the net positive suction curves.

On November 20, 1998, the staff issued RAI 3.4.5-8. In this RAI, the staff asked Duke to determine whether the ONS would have a sufficient operating window at the end of the license renewal period. In a response to RAI 3.4.5-8 issued February 17, 1999, Duke indicated that the predicted operating window at 48 effective full power years (equivalent to 60 years of operation) is sufficient to conduct heatups and cooldowns.

Licensees are required by Appendix G to periodically update their P-T limits based on projected embrittlement and data from its material surveillance program. Since the ONS Reactor Vessel Integrity Program (ORVIP) will provide data to update the P-T limits, it will manage the reduction in fracture toughness in accordance with 10 CFR 54.21(c)(1)(iii).

The applicant identified the analyses for Charpy USE (Appendix G to 10 CFR Part 50) and PTS (10 CFR 50.61) as TLAAs for license renewal. The applicant identified the reactor vessel surveillance program (Appendix H to 10 CFR Part 50) as part of its aging management review. The staff evaluation of the surveillance program is contained in Section 3.4.3.4.1 of this SER.

During the review of the topical report, BAW–2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," the staff had a question (RAI 4 issued to the B&W on August 28, 1996) regarding the need to update the reactor vessel fracture toughness estimates as new data become available. The license renewal applicant has to define a process to ensure that the time-dependent parameters used in the TLAA evaluations reported in BAW–2251 are tracked so that the TLAA remains valid through the period of extended operation. The applicant has stated that the ORVIP, as described in the topical report and associated references, will accomplish this objective. In addition, if new information affects the conclusions of the topical report for the applicant's plant, the applicant will update its TLAA evaluations as appropriate and provide the updated evaluations to the NRC consistent with the plant licensing basis.

On the basis of the applicant's commitment to update the reduction in reactor vessel fracture toughness, the staff concludes that the embrittlement of the reactor vessel will be managed to ensure that it can continue to perform its intended functions for the period of extended operation.

4.2.4.3.2 Charpy Upper Shelf Energy

Appendix G of 10 CFR Part 50 requires that reactor vessel beltline materials must have a Charpy USE of no less than 75 ft-lb initially and must maintain a Charpy USE of no less than 50 ft-lb throughout the life of the vessel, unless it is demonstrated, in a manner approved by the Director, Office of Nuclear Reactor Regulation (NRR), 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. The issue of low upper shelf fracture toughness for Linde 80 welds in B&W vessels was addressed by the B&W for its 16 member plants in topical reports BAW–2192, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of B&W Owners Group Reactor Vessel Working Group for Load Levels A&B Conditions," and BAW–2178, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of Reactor Vessels of

B&W Owners Group Reactor Vessel Working Group for Level C&D Service Loads." Both reports were approved by the NRC on March 29, 1994, in accordance with the methodology and criteria contained in the ASME Code Case N–512, which was later adopted as Appendix K of the ASME Code. This effort was related to Generic Letter (GL) 92–01, Revision 1, "Reactor Vessel Structural Integrity," for demonstrating that, although the predicted end-of-license USE is below 50 ft-lb for some Linde 80 welds in B&WOG vessels, these welds will still provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code.

The applicant provided the Charpy USE values at 48 effective full-power years (EFPY) for the reactor beltline materials used at each ONS unit. The Charpy USE is determined at the 1/4 in. wall thickness (T/4) location. The T/4 neutron fluence values were calculated by using the inside surface neutron fluence and attenuating the neutron fluence in accordance with the ratio of inner surface neutron fluence to T/4 neutron fluence that was determined in the latest reactor vessel surveillance program report. The Charpy USE is maintained above 50 ft-lb for base metal (plates and forgings); however, for the ONS the Charpy USE for weld metal drops below the required 50 ft-lb level prior to 48 EFPY. An equivalent margin analysis was performed for 48 EFPY and is reported in BAW–2275, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of B&W Designed Reactor Vessels for 48 EFPY," which addresses the issue of low USE for Linde 80 welds for license renewal. The staff used the calculation procedures and evaluation criteria in Appendix K of Section XI of the ASME Code to conduct its review of topical report BAW–2275.

Appendix B of BAW-2251 contains the staff's review of BAW–2275, which concludes that the B&WOG's analytical results satisfy the acceptance criteria of Appendix K of the ASME Code. Hence, the Linde 80 welds of the ONS plants have margins equivalent to those of Appendix G of Section XI of the ASME Code. The staff has also examined the recent best-estimate chemistry data from Framatome Technologies Inspection Report No. 99901300/97–01, and concluded, as explained in Appendix B of BAW–2251, that the recent data have no impact on the results and conclusions made in this evaluation. In summary, the staff finds the B&WOG's evaluation of the Charpy USE acceptable for the ONS units for the period of extended operation because the 48 EFPY analysis reported in Appendix B of BAW–2251, and referenced in this application, meets the provisions of 10 CFR 54.21(c)(1)(ii) and applies to the ONS units.

4.2.4.3.3 Pressurized Thermal Shock

The requirements of 10 CFR 50.61 are to protect against PTS transients in pressurized-water reactors. This regulation requires licensees to perform an assessment of the projected values of a reference temperature, RT_{PTS}, for the end-of-life fracture toughness of all reactor beltline material. If the projected reference temperature exceeds the screening criterion established in 10 CFR 50.61, the licensee is required to implement such flux reduction programs as are reasonably practicable to avoid exceeding the screening criterion. The schedule for implementation of such programs may take into account the schedule and anticipated approval by the Director, NRR, of detailed plant-specific analyses to demonstrate acceptable risk with RT_{PTS} above the screening limit. If the licensee cannot avoid exceeding the screening criteria by using a flux reduction program, it must submit a safety analysis to determine what actions are necessary to prevent potential failure of the reactor vessel. Section 50.61 also permits the licensee to perform a thermal annealing treatment to recover fracture toughness, subject to the requirements of 10 CFR 50.66. The regulations require updating of the pressurized thermal shock assessment upon a request for a change in the expiration date of a facility's operating license. Therefore, the RT_{PTS} value must be calculated for the reactor life extension period of 48 EFPY.

The screening criterion established by 10 CFR 50.61 is 270 °F for plates, forgings, and axial welds. The screening criterion is 300 °F for circumferential welds. According to this regulation, if the calculated RT_{PTS} for the limiting reactor beltline materials is less than the specified screening criterion, then the vessel is acceptable with regard to the risk of vessel failure during pressurized thermal shock transients.

RT_{NDT} is the reference temperature of a material. It is an indexing parameter to determine the fracture toughness and is used to determine the amount of embrittlement. RT_{PTS} is related to the RT_{NDT} at the end of life. RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," specifies two methodologies for determining the effect of irradiation on RT_{NDT}. The first methodology, Position 1.1, does not rely on plant-specific surveillance data to calculate delta RT_{NDT} (i.e., the mean value of the adjustment or shift in reference temperature caused by irradiation). The delta RT_{NDT} is determined by multiplying the chemistry factor from the tables in RG 1.99 by the fluence factor. Similarly, the fluence factor is calculated from the neutron flux using an equation or a figure in RG 1.99.

The second methodology in RG 1.99, Revision 2, Position 2.1, relies on plant-specific surveillance data to determine the delta RT_{NDT}. In this methodology, two or more sets of surveillance data are needed. Surveillance data consists of a measured delta RT_{NDT} for a corresponding neutron fluence. The neutron fluence is converted to a fluence factor using an equation provided in RG 1.99. RG 1.99 specifies a procedure and a criterion for determining whether the surveillance data are credible. Using a ratio procedure specified in RG 1.99, Position 2, the measured delta RT_{NDT} values are normalized to the best-estimate chemical composition of the vessel weld. A best-fit line is then determined relating the adjusted delta RT_{NDT} values to the fluence factor. This best-fit line has a zero y-intercept. Therefore, delta RT_{NDT} will be zero at a fluence factor equal to zero. The slope of the best-fit line will equal the chemistry factor. The scatter around the best-fit line, that is, the difference in the predicted value and the measured value for delta RT_{NDT}, must be less than 28 °F for weld metal for the surveillance data to be defined as credible. When a credible surveillance data set exists, the chemistry factor determined from the surveillance data can be used in lieu of the values in the table in RG 1.99, Revision 2, and the standard deviation of the increase in the RT_{NDT} can be reduced from 28 °F to 14 °F for welds.

On February 17, 1999, Duke issued its response to staff RAI 5.4.2 (issued November 20, 1998). In its response Duke recalculated the values of RT_{PTS} for all three ONS units using the most recent materials data reported in BAW–2325, "Response to Request for Additional Information (RAI) Regarding Reactor Vessel Pressure Vessel Integrity." The materials data used to calculate the chemistry factors in the revised RT_{pts} values reported in the ONS response to RAI 5.4.2-1 were obtained from BAW–2325, Revision 1.

The projected RT_{PTS} values for all three units are below the screening criteria at the end of the license renewal period (48 EFPY). For Unit 1, the limiting weld is the axial weld in the intermediate shell with material identification of SA–1073. It has a projected value of RT_{PTS} at 48 EFPY of 230.3°F (the screening criteria is 270°F for axial welds). For Unit 2, the limiting weld is the circumferential weld between the upper and lower shell forgings with material identification WF–25. It has a projected value of RT_{PTS} at 48 EFPY of 296.8°F (the screening criteria is 300°F for circumferential welds). For Unit 3, the limiting weld is the circumferential weld between the upper and lower shells with material identification WF–67. It has a projected value of RT_{PTS} at 48 EFPY of 253.5°F (the screening criteria is 300°F for circumferential welds).

4.2.4.3.3.1 Conclusions

The staff has reviewed the applicant's material data, neutron fluence, and RT_{PTS} calculations and agrees that the projected RT_{PTS} value at 48 EFPY for all three units will be below the PTS screening criteria in 10 CFR 50.61.

4.2.4.3.4 Intergranular Separations Under Weld Cladding

The applicant concluded that growth of intergranular separations has been adequately evaluated in BAW–2251, Appendix C. The applicant also concluded that additional aging management programs are not needed since the NRC staff has found the B&WOG evaluation acceptable. The B&WOG had previously performed a flaw growth analysis of underclad cracks in B&W reactor vessels based on 40 years of plant operation. Topical report BAW–2251 references another topical report, BAW–2274, "Fracture Mechanics Analysis of Postulated Underclad Cracks in B&W Designed Reactor Vessels for the Period of Extended Operation," which contains the B&WOG's evaluation of underclad cracks beneath austenitic stainless steel cladding for the period of extended operation. The B&WOG's methodology in performing the flaw evaluation is consistent with the current well-established flaw evaluation procedure and criterion in the ASME Code and, therefore, is acceptable. The staff examined the unique aspects of the B&WOG approach in the staff's review of BAW–2251 and found the approach to be acceptable for the analysis of intergranular separations under weld cladding.

The B&WOG's methodology, as discussed in BAW–2251, Appendix C, includes the following conservatisms: (1) using the maximum crack depth of 0.165 in. reported by the industry as the initial crack depth instead of the depth of 0.10 in. reported from evaluation of B&W reactor pressure vessels; (2) assuming all underclad cracks are surface cracks; (3) using the fatigue crack growth rate for surface flaws in a water reactor environment; and (4) using a safety factor 17% more than that specified by the ASME Code for Levels A and B (normal and upset) loading and 72% more than for Levels C and D (emergency and faulted) loading. In summary, the staff found the B&WOG's underclad cracking flaw growth analysis acceptable for the ONS units for the period of extended operation and therefore the staff agrees with the applicant that no inspection program is needed.

4.2.4.4 Review Findings for Reactor Neutron Embrittlement and Underclad Cracking

The staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii) and (c)(1)(iii), that aging effects associated with the reactor vessel integrity will be adequately managed so there is reasonable assurance that these systems will perform their intended functions in accordance with the CLB during the period of extended operation.

4.2.5 Reactor Vessel Internals

4.2.5.1 Introduction

The staff has reviewed Section 5.4.3 of Exhibit A 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 the TLAAs for the reactor vessel internals.

4.2.5.2 Summary of Technical Information in the Application

In section 5.4.3 of Exhibit A of the LRA, the applicant states that TLAAs applicable to the ONS vessel internals are addressed in topical report BAW–2248, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals." TLAAs identified in the LRA include:

- Flow-induced vibration endurance limit assumptions
- Transient cycle count assumptions for the replacement bolting
- Reduction in fracture toughness

The LRA states that the reactor vessel internals aging management program (RVIAMP) will assure that appropriate action is taken in a timely manner to ensure continued validity of the design of the reactor vessel internals.

4.2.5.3 Staff Evaluation

In topical report BAW–2248, the identified applicable TLAAs were evaluated for the period of extended operation consistent with the requirements of 10 CFR 54.21(c)(1).

The flow-induced vibration fatigue limit assumptions were based on 10^{12} cycles for 40 years. The analysis was extended into the period of extended operation for license renewal by conservatively increasing the number of cycles to 10^{13}, then determining the endurance limit using the latest ASME fatigue curves. The component stress values were found to be less than the endurance limit, rendering the evaluation acceptable, according to the requirements of 10 CFR 54.21(c)(1)(ii).

In topical report BAW–2248, the B&WOG indicates that the design cyclic loadings and thermal conditions used for the analyses are defined in the component design specifications and that the flow-induced vibration input used in the analysis was obtained from hot functional testing data contained in the listed analyses documents. The ability to withstand cyclic loading without fatigue failure was evaluated using a cumulative usage factor methodology. For each utility, the number of transients accrued to date was conservatively extrapolated, and in all cases it was found that the number of design cycles would not be exceeded in the period of extended operation. The B&WOG reported that each of the participating utilities monitors occurrences of design transients and is thus managing the potential for cracking resulting from fatigue. The topical report indicates that the plants must continue to monitor and track occurrences of design transients.

The TLAA described as "reduction in fracture toughness" is related to the acceptability of the reactor vessel internals under LOCA and seismic loading. BAW–2248 states that Appendix E to BAW–10008, Part 1, Revision 1, "Reactor Internals Stress & Deflection Due to LOCA & Max Hypothetical Earthquake," concludes "that at the end of 40 years, the internals will have adequate ductility to absorb local strain at the regions of maximum stress intensity, and that irradiation will not adversely affect deformation limits." BAW–2248 also states that this TLAA will be resolved on a plant-specific basis per 10 CFR 54.21 (c)(1)(iii) based on the results and conclusion of the planned B&WOG RVIAMP. Duke has stated that appropriate action will be taken in a timely manner to ensure continued validity of the design of the ONS reactor vessel internals. Plant-specific analysis is required to demonstrate that, under LOCA and seismic loading and with irradiation accumulated at the expiration of the period of extended operation, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and will meet the deformation limits. The applicant must provide a plan to develop data to demonstrate that the internals will meet the deformation limits through the period of extended operation. This was identified as Open Item 4.2.5.3-1 in the June 16, 1999, SER. Subsequently, in a letter dated December 17, 1999, Duke committed to perform the plant-specific analysis and develop data to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license. The staff has determined this program will adequately manage the irradiation aging effect in accordance with 10 CFR 54.21 (c)(1)(iii). Thus, Open Item 4.2.5.3-1 is closed.

BAW–2248 also identifies a fourth TLAA regarding flaw growth acceptance in accordance with the ASME B&PV Code, Section XI ISI requirements. This TLAA is identified in the topical report as requiring a plant-specific evaluation, and as such is not evaluated in the topical report. The applicant did not address the applicability of this flaw growth TLAA to ONS, and this was identified as Open Item 4.2.5.3-2 in the June 16, 1999, SER. Subsequently, in a letter dated

October 15, 1999, Duke responded that no flaws have been identified in the ONS RVI, and hence no evaluation is required. This closes Open Item 4.2.5.3-2.

4.2.5.4 Review of Findings for Reactor Vessel Internals

The applicant has identified and evaluated the TLAAs associated with the reactor vessel internals in accordance with 10 CFR 54.21(c) and has provided justification for compliance with 10 CFR 54.21(c)(1)(ii) and (c)(1) (iii).

4.2.6 Fatigue of Reactor Coolant Pump Flywheel

4.2.6.1 Introduction

The applicant has addressed the TLAA related to fatigue of the reactor coolant pump (RCP) flywheel in OLRP–1001, Section 5.4.4 of Exhibit A of the LRA.

4.2.6.2 Summary of Technical Information in the Application

The RCP motors are large, vertical, squirrel cage induction motors. The motors have flywheels to increase rotational inertia, thus prolonging pump coastdown and assuring a more gradual loss of main coolant flow to the core in the event that pump power is lost. The flywheel is mounted on the upper end of the rotor, below the upper radial bearing and inside the motor frame. The assumed operation of the RCP was 500 motor starts over 40 years. The aging effect of concern is fatigue crack initiation in the flywheel bore keyway from stresses due to starting the motor. Therefore, this topic is considered to be a TLAA for license renewal. The applicant has addressed this TLAA by projecting the CLB to the end of the period of extended operation.

4.2.6.3 Staff Evaluation

The RCP flywheels have been designed for 10,000 starts that provide a safety factor of 20 over the original operation assumptions. Reaching 10,000 starts in 60 years would require a pump start every 2.1 days, on average. Since a pump start normally occurs every 200 to 300 days, on average, this conservative design is considered valid for the period of extended operation. Therefore, the staff concludes that the applicant meets the requirements of 10 CFR 54.21(c)(1)(ii).

In addition, the effects of aging on the integrity of the RCP flywheel will be adequately managed by the ONS Improved Technical Specification 5.5.8, "Reactor Coolant Flywheel Inspection Program." This program provides for inspection of each RCP flywheel. At approximately three-year intervals, the bore and keyway of each RCP flywheel is required to be subjected to an inplace volumetric examination. If maintenance or repair activities necessitate flywheel removal, and if the time interval since the last such inspection is greater than 6 2/3 years, a surface examination of exposed surfaces and a complete volumetric examination is required.

The interval may be extended up to one year to permit inspections to coincide with a planned outage. The staff finds the program adequate to manage the effects of aging for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(iii).

4.2.6.4 Review Findings for Fatigue of Reactor Coolant Pump Flywheel

The staff concludes that the applicant has provided an acceptable TLAA involving components of the RCP flywheel as defined in 10 CFR 54.3 and meets 10 CFR 54.21(c)(1)(ii) or (iii).

4.2.7 Fatigue Analysis of Class II and Class III Components

4.2.7.1 Introduction

The staff has reviewed Section 5.5.1 of Exhibit A 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 the TLAAs for fatigue analysis of Class II and Class III mechanical components.

4.2.7.2 Summary of Technical Information in the Application

Section 5.5.1 of the ONS LRA indicates that thermal fatigue of Class II and Class III mechanical components is considered to be a TLAA. The LRA states that thermal fatigue is considered an aging effect and involves time-limited assumptions defined by the current term (7,000 cycles). Based on an engineering review that concluded 7,000 cycles bounds the period of extended operation, the applicant has determined that the existing thermal fatigue analysis for Class II and Class III mechanical components within the scope of license renewal remains valid for the period of extended operation.

4.2.7.3 Staff Evaluation

Many of the ONS piping system components within the scope of license renewal are designed to American National Standards Institute Standard B31.1, B31.7 Class II and Class III code requirements. While these code requirements do not require an explicit fatigue analysis, they do specify allowable stress levels, based on the number of anticipated thermal cycles.
Section 5.5.1 of Exhibit A of the LRA indicates that the results of the applicant's engineering analysis determined that the design temperatures and operating conditions of these mechanical system components will result in equivalent full-temperature cycles less than the 7,000 assumed thermal cycles during the period of extended operation. Therefore, it was determined that the existing analysis of thermal fatigue of mechanical components within the scope of license renewal is valid for the period of extended operation.

On the basis of the information provided by the applicant, the staff concurred with the applicant's conclusion that 7,000 assumed thermal cycles will not be exceeded during the period of extended operation. Therefore, the existing thermal fatigue analysis for the Class II and Class III mechanical components meets the criteria of 10 CFR 54.21(c)(1)(i).

4.2.7.4 Review Findings for Fatigue Analysis of Class II and Class III Components

The staff concluded that for the TLAA relating to the thermal fatigue analysis of Class II and Class III mechanical components, the applicant has provided sufficient information to justify compliance with 10 CFR 54.21(c)(1)(i).

4.2.8 Environmental Qualification of Electrical Equipment

The ONS 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.

4.2.8.1 Introduction

The staff has reviewed Section 5.6 of the ONS 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 the EQ TLAA. In addition, Section 1.5.3 of the LRA was reviewed regarding GSI-168, "Environmental Qualification of Electrical Components."

4.2.8.2 Summary of Technical Information in the Application

The ONS 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 ONS methodology used to evaluate the EQ TLAA.

Scope of EQ Equipment

Based on a review of the ONS EQ documentation, the applicant identified electrical equipment that has a qualified life of at least 40 years, during which the electrical equipment can perform its intended function in the event of a LOCA or a high-energy line break inside the reactor building and a high-energy line break outside the reactor building. The scope of equipment in the EQ program includes:

- Safety-related electrical equipment in a harsh environment required to mitigate an accident or whose subsequent failure can degrade safety systems or mislead the operator

- Non-safety-related electrical equipment in a harsh environment whose failure could prevent a safety function or mislead the operator
- Post-accident monitoring equipment located in a harsh environment designated as RG 1.97 equipment

EQ Process

The EQ process is controlled by the EQ master list and the EQ maintenance manual. The EQ master list provides the following equipment information:

- Equipment tag number
- Manufacturer/model or series number of equipment
- The building, floor elevation, and specific equipment location
- Whether equipment is in a harsh or mild environment
- The applicable EQ maintenance manual section
- Equipment installation date
- Equipment qualified life

The EQ maintenance manual addresses the following activities:

- EQ-mandated maintenance to maintain equipment qualified life
- Equipment qualified life and any parts to be replaced and the interval
- The electrical termination method
- Whether the cable entrance must be sealed to prevent moisture intrusion
- Required installation/mounting configurations
- Equipment shelf life and storage requirements
- Procurement and reorder information for specific equipment

Replacement of Equipment

The ONS work management system generates a notice to alert engineering that the equipment is scheduled for replacement sufficiently in advance of the expiration of the qualified life of a piece of EQ equipment to ensure that no functional interruption occurs. The options available are as follows:

- Replace the existing equipment with identical equipment.

- Replace the equipment with different equipment that performs the same function and that is already evaluated under the EQ program.

- Replace the equipment with equipment that performs the same function and is not currently evaluated under the EQ program. This requires a QA Condition 1 calculation to verify that the assumptions and conclusions are valid and to document the qualification of the equipment.

- Reanalyze the qualified life calculation. If excess conservatism exists in the original qualified life calculation, then reanalysis is performed for a specific application to extend the qualified life. The reanalysis is documented under a QA Condition 1 calculation that has data to verify all assumptions and conclusions. Parameter conservatism may exist in the ambient temperature of the equipment, in an unrealistically low activation energy, or in the application of the equipment. The reanalysis is performed as follows:

  - Analytical Methods - The thermal model used to perform a reanalysis is based on Arrhenius methodology. With regard to thermal aging, moisture has not been identified as a significant aging mechanism. EQ equipment is typically sealed and cable insulation is protected from the occasional inadvertent spray. During normal operation, equipment is only subjected to ambient humidity levels (20–90%). Exposure to moisture due to leaks is investigated case by case. The analytical method used for radiation analysis is to identify the 40-year radiation dose from the EQ criteria manual for the area where the equipment is installed, multiply that value by the ratio of the evaluation period divided by 40 years (60 years/40 years = 1.5), and add the applicable accident radiation dose to obtain the total integrated dose for the equipment.

  - Data Collection and Reduction Methods - The primary method used for reanalysis is reducing excess conservatisms in the equipment service temperatures. Temperature data used in a reanalysis are obtained from actual temperature measurements in the area around the equipment being reanalyzed. Temperature measurements are made through monitors for Technical Specification compliance, other installed monitors, plant operator measurements, and temperature sensors on large motors while the motor is not running. Temperature measurements are reduced based on achieving a specific statistical confidence level. Typically, a 99.73% confidence mean temperature is calculated, which means that 99.73% of the time the area temperature is at or below this temperature. For reanalysis, the actual calculated temperature is used or the calculated temperature is used to validate, or show the conservatism of a design temperature for a reanalysis.

  - Underlying Assumptions - There have been no major plant modifications or events at the ONS of sufficient duration to have changed the temperature and radiation values that were used in the underlying assumptions in the EQ calculations. Conservatisms in the EQ equipment qualification analyses have been sufficient to absorb environmental changes occurring due to plant modification and events.

- Acceptance Criteria and Corrective Actions - The acceptance criterion associated with the reanalysis of a qualified life is the documented confirmation that the equipment is qualified for some period beyond the previously existing qualified life. Corrective action is not applicable to reanalysis of a qualified life calculation. The EQ program at the ONS ensures that adequate margin, as described in Institute of Electrical and Electronic Engineers (IEEE) Standard 323–1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations," and the Division of Operating Reactors (DOR) Guidelines, is maintained in all reanalyses. If adequate margin cannot be maintained, then adequate justification must be provided. The equipment qualification is not extended and the equipment is replaced as scheduled prior to the expiration of the existing qualification if the reanalysis does not maintain adequate margin and less margin cannot be justified.

Refurbishment of EQ Electrical Equipment

EQ equipment that is in need of refurbishment is replaced with new equipment or previously refurbished equipment taken out of storage. The equipment that has been removed is placed in storage after it has been refurbished. Refurbishment is a process that preserves the qualification status of equipment and is typically accomplished by replacing items such as gaskets, seals, and wires, which have a limited life. The EQ maintenance manual provides guidance for shelf life of refurbished equipment and identifies all EQ limited-life replacement parts for particular equipment, manufacturers, and models.

Ongoing Qualification/Retesting

For electrical equipment that has a qualified life less than the required design life of a nuclear power generating station, "ongoing qualification" is a method of long-term qualification involving additional testing. Ongoing qualification or retesting as described in IEEE Standard 323–1974, Section 6.6(1) or (2), is not currently considered by the ONS to be a viable option and there are no plans to implement such an option. If this option becomes viable in the future, ongoing qualification or retesting would be incorporated into ONS directives administering the EQ program and the associated activities would be performed in accordance with accepted industry and regulatory standards.

Procurement of EQ Equipment

The nuclear station directive for equipment procurement, the EQ program, and the quality standards manual control the procurement policy for EQ equipment. The procurement section in the EQ maintenance manual addresses the manufacturer or vendor from which to purchase the equipment, the test reports to be referenced on the requisition, and the specification numbers to which the equipment is to be purchased. Specifications for procurement of new EQ equipment are reviewed and test plans are reviewed and approved prior to testing to assure compliance with the specification. The EQ master list and the EQ maintenance manual are updated as new EQ equipment is procured.

Plant Environmental Changes

The EQ criteria manual identifies the harsh environmental areas of the plant for LOCAs, high-energy line breaks, and radiation. The EQ criteria manual is a document controlled by QA Condition 1. Measurements of critical parameters such as containment temperatures for Technical Specification requirements are trended on an ongoing basis. When a significant environmental change is identified, a review of the qualification of affected EQ equipment is performed and any required changes to the equipment's qualified life are made. When reanalysis is used to extend the qualified life, the environmental parameters for the equipment are verified. Equipment reanalyses are performed by calculations whose assumptions and environmental data are reviewed periodically for continued validity.

EQ Generic Safety Issue

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 until some later point in the period of extended operation, at which time one or more reasonable options would be available to adequately manage the effects of aging.
- An applicant could develop a plant-specific aging management program that incorporates a resolution to the aging issue.

For addressing issues associated with GSI–168, “Environmental Qualification of Electrical Components,” 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 5.6 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, at which time one or more reasonable options would be available to adequately manage the effects of aging.

4.2.8.3 Staff Evaluation

In accordance with 10 CFR 54.21(c)(1), the staff reviewed Section 5.6 of Exhibit A 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) be adequately managed for the period of extended operation. Section 1.5.3 of the LRA was also reviewed regarding GSI–168. After completing the initial review, the staff issued an RAI on November 25, 1998, and met with Duke representatives on January 19, 1999, to discuss RAIs 5.6-1, 5.6-2, and 5.6-3 in the EQ area. The responses to the November 25, 1998, staff RAIs were received on February 8, 1999.

The applicant is using standard approved EQ methodologies and acceptance criteria applicable to EQ as defined by NRC BL 79–01B, "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 ONS actions for short-lived EQ equipment are also acceptable for long-lived EQ equipment. As discussed below, the staff concurs with the EQ methodology described by the applicant.

The applicant is implementing 10 CFR 54.21(c)(1)(i), (ii), and (iii) with regard to the evaluation of the EQ TLAA. The methodology described by the applicant to evaluate the EQ TLAA was reviewed by the staff in the following areas:

- Scope of EQ program
- EQ process
  - EQ master list
  - EQ maintenance manual
  - Replacement of EQ equipment
    - Replace with identical equipment
    - Replace with different equipment currently in the EQ program
    - Replace with different equipment not currently in the EQ program
    - Reanalyze the qualified life calculation
  - Refurbishment of EQ equipment
  - Procurement of EQ equipment
  - Plant environmental changes

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(i)

LRA Sections 5.6.1, "TEC Monitor Accelerometers," 5.6.24, "Viking Penetration Assemblies," and 5.6.26, "Rosemount RTDs" are based on option (i) of 10 CFR 54.21(c)(1), to demonstrate that the analyses remain valid for the period of extended operation. Based on the staff's review of the thermal and radiation summaries for the above electrical equipment and the review of calculation OM–360–24 for the Rosemount resistance temperature detectors (RTDs) and calculation OM–337.00–0080001 for the Viking electrical penetrations during the January 19, 1999, meeting at the NRC, the staff finds the demonstration of 10 CFR 54.21(c)(1)(i) to be acceptable for the above electrical equipment. The January 21, 1999, meeting summary documents the results of the staff's review of these calculations.

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(ii)

The following list of electrical equipment identified in Section 5.6 of the LRA is based on option (ii) of 10 CFR 54.21(c)(1), to demonstrate that the analyses have been projected to the end of the period of extended operation:

- Limitorque actuators
- Anaconda EPR/Hypalon & EPR/neoprene cables
- BIW CSPE cables
- Brand-Rex & Samuel Moore PVC cables
- Brand-Rex Flame Retardant XLPE cables
- ITT Suprenant & Raychem Cross-linked Polyalkene hook-up wire
- Kerite-HTK cables
- Okonite/EPR/Neoprene cables
- Samuel Moore EPDM/Hypalon cables
- Scotchcast 9 & Swagelok quick-connect assemblies
- Raychem NCBK nuclear breakout splice assemblies
- Raychem NPKV nuclear plant stub connection kit
- Raychem WCSF-N in-line splice assemblies
- Westinghouse HPI pump & LPI pump motors
- Conax electrical penetration assemblies
- D. G. O'Brien electrical penetration assemblies
- States & Stanwick terminal blocks
- Barton Model 764 transmitters

Based on the staff's review of the thermal and radiation summaries for the above electrical components and the review of calculation OSC–7167 for Limitorque actuators, calculation OSC–6530 for Okonite EPR/neoprene cables, and calculation OSC–7055 for Samuel Moore EPDM/Hypalon cables during the January 19, 1999, meeting at the NRC, the staff finds the demonstration of 10 CFR 54.21(c)(1)(ii) to be acceptable for the above electrical equipment.

The January 21, 1999, meeting summary documents the results of the staff's review of these calculations.

TLAA Demonstration for Option 10 CFR 54.21(c)(1)(iii)

The following list of electrical equipment identified in Section 5.6 of the LRA is based on option (iii) of 10 CFR 54.21(c)(1) to demonstrate that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation:

- Rotork actuators
- EGS grayboots
- EGS connectors
- Joy/Reliance motors
- Louis-Allis motors
- Reliance motors
- Westinghouse BS pump motors
- Conax RTDs
- Weed RTDs
- Valcor Solenoid valves
- Barton/Westinghouse switches
- Gems Delaval transmitters
- Rosemount transmitters

The Rotork actuators, Joy/Reliance motors, Louis-Allis motors, Westinghouse BS pump motors, Gems Delaval transmitters, and Rosemount transmitters are pieces of original plant equipment that have a 40-year qualified life. The applicant has no current plans to reanalyze and extend the qualified lives of this equipment and will replace this equipment before their qualified life expires in accordance with the ONS EQ program.

The EGS Grayboots, EGS connectors, Reliance motors, Conax RTDs, Weed RTDs, Valcor solenoid valves, and Barton/Westinghouse switches are not original plant equipment and are replacements for equipment removed from service in the years 1986 through 1994. These replacements are all qualified for 40 years and their qualified lives expire between the years 2026 and 2034, 7 to 8 years before the end of the period of extended operation. The applicant will replace this equipment in accordance with the ONS EQ program before the end of the qualified life unless an analysis is performed to extend the qualified life

In both of the above categories, the ONS EQ program and its associated site administrative controls have the necessary elements to ensure that the effects of aging on the intended functions of the qualified equipment will be adequately managed for the period of extended operation. The staff finds the above approaches to be an acceptable demonstration of 10 CFR 54.21(c)(1)(iii) for managing the effects of aging for the period of extended operation.

GSI–168 Finding

The staff finds the applicant's approach for resolution of GSI–168 acceptable with regard to license renewal and consistent with the June 2, 1998, staff guidance to industry, which 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.

4.2.8.4 Review Findings for Environmental Qualification of Electrical Equipment

The staff has reviewed the information in Sections 1.5.3 and 5.6 of Exhibit A of the LRA and additional information provided in the January 19, 1999, meeting on EQ with the staff, and the February 8, 1999, letter in response to NRC RAIs. The ONS EQ calculations that were reviewed by the staff during the January 19, 1999, meeting were used to make a confirmatory finding but were not relied upon solely to make the following 10 CFR 54.29 finding. On the basis of this review, the staff concludes that the applicant has supplied an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1), that, for TLAAs related to EQ for 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.

4.2.9 Fatigue of Polar Crane

4.2.9.1 Introduction

The load cycle limit of the ONS polar cranes (PCs) was identified as a TLAA by reviewing correspondence on the ONS dockets associated with the control of heavy loads. In 1981, the NRC issued GL 81–07, "Control of Heavy Loads," and NUREG–0612, "Control of Heavy Loads." One of the concerns expressed by the NRC staff during reviews of responses related to NUREG–0612 was the potential for fatigue of cranes due to frequent loadings at or near design conditions. The applicant states that cranes at the ONS are not generally subjected to frequent loads at or near design conditions. The topic of lift cycles of cranes at or near rated load is considered to be a TLAA for the ONS because the analysis meets all of the criteria contained in 10 CFR 54.3.

4.2.9.2 Summary of Technical Information in the Application

During earlier reviews related to NUREG–0612, the applicant stated that the PC was the bounding ONS crane for the lift of loads at or near rated capacity. Other cranes at the ONS were considered to be bounded by the PC since the projected number of lifts by other cranes of loads at or near capacity for the life of the plant was less than the projected number of lifts by the PC for the life of the plant. The number of lifts at or near the rated capacity of the PC over a 40-year life was estimated to be approximately 100. This number was based upon the expected number of annual refueling cycles for the life of the plant and two lifts at or near capacity for each refueling outage, one lift for removing the reactor vessel head at the beginning of refueling and the second lift to replace it on the reactor vessel head at the end of refueling. The number of lifts is conservative because refueling now occurs approximately once every 18 months instead of annually. The NRC agreed with the applicant's assessment that fatigue was not a concern for the ONS PCs during the review related to NUREG–0612.

Subsequent to these reviews, the applicant installed an independent spent fuel storage installation (ISFSI) at the ONS, that became operational in 1990. The operation of the ISFSI resulted in additional lifts by the spent fuel pool (SFP) cranes near their rated lifting capacity. The ISFSI is currently licensed for 88 casks, which equates to 176 full lifts over the life of the plant. Because some of the canisters in the ONS ISFSI are assumed to be nontransportable, they will be returned to the SFP so that the spent fuel can be removed and repackaged into multipurpose canisters. The repackaging will result in additional lifts. The estimate of the number of heavy load lifts of the SFP cranes requires assumptions about when the high-level waste repository will be licensed and capable of accepting spent fuel. Current estimates are that this will not occur until late in the current licensed term of the ONS. Overall estimates for the additional casks are 615 additional heavy load lifts through 2013, for a total of 1,055 lifts on the two spent fuel cranes for the current operating term. Extending this estimate through 2034 still results in a number of estimated heavy lifts below the required threshold of 20,000 cycles.

4.2.9.3 Staff Evaluation

The repackaging of the canisters in the ISFSI will result in three full lifts per cask. These lifts consist of moving the canisters from the transfer car to the pool, moving the canisters from the support frame to the decon pit, and moving the canisters from the decon pit to the car. The applicant indicated that this repackaging will result in an additional 264 full lifts for the 88 casks and a total of 440 full load lifts of one SFP crane for the 88 casks. The applicant considers this to be conservative because all lifts are assigned to one SFP crane rather than divided between the two ONS SFP cranes. The staff agrees with this assessment. The applicant estimates that an additional 123 casks would be needed to store spent fuel onsite through 2013 and to completely empty the pools. Each cask would require two full lifts to initially load each cask and then three full lifts to repackage each cask for shipment. These casks could be multipurpose casks, thereby eliminating the need for three additional lifts per cask, but three additional lifts have been assumed for conservatism. Overall results for the additional casks are 615 additional heavy load lifts through 2013, for a total of 1,055 lifts on one SFP crane for the current operating term. Extending this estimate through 2034 still results in approximately 2,000 heavy load lifts, which is well below the threshold of 20,000 cycles stipulated in the Crane Manufacturer's Association specifications.

According to the applicant, the existing analyses addressing heavy load lifts of both the PCs and the SFP cranes are considered to be valid for the period of extended operation. The staff agrees with this overall assessment and finds that the applicant meets 10 CFR 54.21(c)(1)(i). However, there is a concern related to the components of the PC. Typically, some of the components of the PC system, such as PC rails, are constructed of carbon steel, which has a lower allowable stress range. The applicant's analyses do not distinguish between components that have different allowable-stress ranges. In RAI 5.7.1-2 issued April 8, 1999, the staff asked Duke to submit a justification that the lower limit of the stress range will not be exceeded during service life. In a response dated May 10, 1999, Duke clarified that the PC rails and girders are constructed of A36 and A7 steel, respectively. For 60 years of operation with the crane lifting at or near its rated capacity, the crane will be subjected to approximately 243 cycles. The number of projected cycles is much less than the minimum number of allowable cycles for any steel, which is 20,000 cycles. Since the crane is not expected to exceed the originally assumed number of design loading cycles, the original design remains bounding. The staff finds that the applicant's response is reasonable and acceptable and that it meets 10 CFR 54.21(c)(1)(ii).

4.2.9.4 Review Findings for Fatigue of Polar Crane

On the basis of the review as discussed above, the staff concludes that the applicant has presented an acceptable TLAA of components of the PC, as defined in 10 CFR 54.3 and that it meets 10 CFR 54.21(c)(1)(i) and (ii).

4.2.10 Aging of Boraflex in Spent Fuel Racks

4.2.10.1 Introduction

The applicant addressed the TLAA for the spent fuel rack Boraflex in Section 5.7.2, "Spent Fuel Rack Boraflex," of Exhibit A of the LRA. The applicant stated that, because the NRC approved the use of spent fuel racks containing Boraflex for a 40-year service life, aging of Boraflex meets the criteria of 10 CFR 54.3 and should be considered as a TLAA for the purpose of license renewal. Section 5.7.2 of Exhibit A of the LRA describes the existing analyses for verification of the design functions of Boraflex and explains why these analyses remain valid and can be projected to the end of the period of extended operation. Section 5.7.2 of the LRA also demonstrates that the TLAA will meet the requirements of 10 CFR 54.21(c)(1)(i), (ii), and (iii) and will adequately manage the effects of aging on the spent fuel racks during the period of extended operation.

4.2.10.2 Summary of Technical Information in the Application

Boraflex is a material used in spent fuel racks to help maintain an effective multiplication factor (k_{eff}) less than or equal to 0.95. It is a silicon polymer containing a specified amount of boron-10 in the form of boron carbide particles that absorb neutrons and ensures that the design basis for criticality control is met throughout the service life of the racks. In the high gamma radiation fields existing in the SFP, Boraflex tends to degrade. It loses its elasticity, becomes brittle, and shrinks, causing gaps to form. It also loses some of its boron carbide particles, becoming a less effective neutron absorber. Although the tests performed by the manufacturer have indicated that no significant degradation could occur for a normal service life of 40 years, several tests and analyses were developed by the industry to verify acceptable performance of the Boraflex exposed to SFP water. Currently, the applicant has a Boraflex Monitoring Program, which involves several tests and analyses to ensure that no unexpected degradation of the Boraflex material compromises the criticality analysis in support of the design of spent fuel storage racks for 40 years of service. In the LRA, the applicant demonstrated, pursuant to 10 CFR 54.21(c)(1), that these analyses are valid and applicable for monitoring Boraflex performance for the period of extended operation.

4.2.10.3 Staff Evaluation

The tests in the Boraflex monitoring program include visual surveillance of the stainless steel clad Boraflex coupons, which were exposed to the spent fuel pool environment for several years. The results of these tests have indicated that degradation of Boraflex was minimal. The applicant also performed blackness testing to verify gap formation in the Boraflex panels. These tests were performed on 33 Boraflex panels in Units 1 and 2 and on 34 panels in Unit 3. In all cases no detectable gap formation was observed. The positive results of these tests confirmed that up to now no observable degradation of Boraflex has occurred. The applicant will monitor the future performance of Boraflex through two programs: measurement of silica in the SFP water and use of the RACKLIFE computer code. Loss of boron carbide from degraded Boraflex panels is always accompanied by a simultaneous release of silica. Therefore, measurement of silica levels provides an indication of the rate at which boron-10 is removed. This method can be used for in-situ trending of Boraflex degradation. The RACKLIFE computer code was developed by EPRI to assess overall Boraflex thinning on the basis of several operating parameters currently used in the ONS plant. The staff has reviewed the technical basis of the RACKLIFE code and found that the code provides an acceptable means to determining the amount of Boraflex thinning in the spent fuel racks. In addition to these methods for ensuring the integrity of Boraflex, the applicant will perform criticality analyses assuming no credit for the presence of Boraflex in the spent fuel racks. The results of these analyses will be included in the program for determining future performance of Boraflex. Satisfactory performance of Boraflex, as determined by surveillance tests and a well-established program to predict its future behavior, will provide assurance that the Boraflex in the spent fuel racks will function satisfactorily during the period of extended operation.

4.2.10.4 Review Findings for Aging of Boraflex Spent Fuel Racks

The staff has reviewed the information in Section 5.7.2 of Exhibit A to the LRA. On the basis of this review, as described above, the staff concludes that the applicant supplied an acceptable demonstration that the TLAA of spent fuel rack Boraflex meets the requirements of 10 CFR 54.21(c)(1) because:

- The analyses for determining Boraflex integrity remain valid for the period of extended operation.
- By using predictive methodologies, these analyses could be projected to predict behavior of Boraflex for the period of extended operation.
- Review of these analyses by the staff has indicated that the effects of aging on the intended functions of Boraflex will be adequately managed and that it will remain an effective neutron absorber in the spent fuel racks for the period of extended operation.

5 REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

During the 465th meeting of the Advisory Committee on Reactor Safeguards (ACRS) on September 1–3, 1999, the ACRS reviewed the NRC staff's safety evaluation report (SER) related to the license renewal application (LRA) for the Oconee Nuclear Station (ONS), Unit Nos. 1, 2, and 3. The ACRS Subcommittee on Plant License Renewal also reviewed the SER on June 30–July 1, 1999. Findings of these two reviews are documented in an ACRS interim letter dated September 13, 1999. The letter noted that there were a number of open and confirmatory items that must be resolved before the staff could complete the safety evaluation for the renewal application. The staff responded to the ACRS letter on October 8, 1999. The staff's response stated that "the staff will arrange to meet with the Committee to describe the resolution of the open issues and confirmatory items, as soon as the technical basis for the resolution has been settled." The staff briefed the ACRS subcommittee on February 24, 2000, and the full committee on March 2, 2000, regarding the resolution of the open and confirmatory items.

During the 470th meeting, March 1–4, 2000, the ACRS completed its review of the ONS LRA, as documented in a letter dated March 13, 2000. In the letter the ACRS concluded that Duke has properly identified the structures, systems, and components (SSCs) that are subject to aging management programs according to the requirements of 10 CFR Part 54; that possible aging mechanisms associated with passive, long-lived SSCs have been appropriately identified; and that the programs instituted to manage aging-related degradation of the identified SSCs are appropriate and provide reasonable assurance that Oconee Units 1, 2 and 3 can be operated in accordance with their current licensing basis for the period of the extended license without undue risk to the health and safety of the public. A copy of the March 13, 2000, letter is included in this report.

March 13, 2000

The Honorable Richard A. Meserve
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Dear Chairman Meserve:

SUBJECT: REPORT ON THE SAFETY ASPECTS OF THE LICENSE RENEWAL APPLICATION FOR THE OCONEE NUCLEAR STATION, UNITS 1, 2 AND 3

During the 470th meeting of the Advisory Committee on Reactor Safeguards, March 1-4, 2000, we completed our review of Duke Energy Corporation's application for license renewal of the Oconee Nuclear Station, Units 1, 2 and 3 and the related Final Safety Evaluation Report (FSER). Our review included a plant visit and four meetings, one of which was conducted in Clemson, South Carolina. We had the benefit of insights gained from two meetings concerning generic license renewal issues and the review of another license renewal application. We provided an interim letter dated September 13, 1999, concerning the Oconee license renewal application. During these reviews, we had the benefit of the documents referenced.

Conclusion

On the basis of our review of Duke's application, the staff's FSER, and the resolution of the open and confirmatory items identified in the June 1999 Safety Evaluation Report (SER), we conclude that:

- Duke has properly identified the structures, systems, and components (SSCs) that are subject to aging management programs according to the requirements of 10 CFR Part 54.

- Possible aging mechanisms associated with passive, long-lived SSCs have been appropriately identified.

- The programs instituted to manage aging-related degradation of the identified SSCs are appropriate and provide reasonable assurance that Oconee Units 1, 2 and 3 can be operated in accordance with their current licensing basis for the period of the extended license without undue risk to the health and safety of the public.

Background and Discussion

This report is intended to fulfill the requirement of 10 CFR 54.25 that each license renewal application be referred to the ACRS for a review and report. Duke requested renewal of the operating licenses for the Oconee Units 1, 2 and 3 for a period of 20 years beyond the current license term. The FSER documents the results of the staff's review of information submitted by Duke, including those commitments that were necessary to resolve open and confirmatory items identified by the staff in its SER. The staff's review included the verification of the completeness of the identification and categorization of the SSCs considered in the application; the validation of the integrated plant assessment process; the identification of the possible aging mechanisms associated with each passive long-lived component; and the adequacy of the aging management programs.

In the SER, the staff identified a number of open and confirmatory items. The staff and Duke have now resolved all open items and addressed all confirmatory items, in part through additional commitments made by Duke. The Duke commitments will become a part of the plant's licensing basis and will be added to the Oconee Final Safety Analysis Report (FSAR). This will make the commitments enforceable.

Several of the open items, such as the completeness of the methodology used to identify SSCs that are within the scope of Part 54 and the consideration of the effects of the reactor coolant environment on fatigue life, may have generic implications for future license renewal applications.

Because Oconee was licensed before NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," was issued in September 1975, the safety-related SSCs at Oconee do not completely bound the set of SSCs that are relied upon to be functional during and following design basis events. Consequently, nonsafety-related components that are relied upon to perform safety-related functions are within the scope of Part 54. As noted in our interim letter, this is a generic issue for older plants. The process of identifying these additional SSCs without expanding the current licensing basis of Oconee required significant interaction between the staff and the licensee.

In accordance with the license renewal scoping criteria specified in 10 CFR 54.4 (a), the staff identified a set of additional events that had not been considered in Duke's license renewal application. Although these events were not part of the original FSAR accident analysis, Duke was asked to perform a plant-specific evaluation. We agree with the staff determination that these events should be considered in the analysis of scope. Duke evaluated these events to identify additional SSCs that should be included within the scope of license renewal. This evaluation did not identify any additional SSCs and provides further evidence that SSCs within the scope of 10 CFR Part 54 have been appropriately identified.

Insulated cables in localized areas in the Oconee containment have been identified in station problem reports as exhibiting accelerated thermal and radiation-induced aging effects due to adverse environments. Where the design and installation conditions responsible for the accelerated aging have not been corrected, the staff requested that an aging management program be instituted as part of the license renewal application. The staff also requested that an aging management program be instituted for medium-voltage cables located in trenches or buried in the ground, where the cables are exposed to moisture.

Duke responded by instituting an Insulated Cables Aging Management Program that includes cables within the scope of license renewal that are installed in locations with adverse environments and could be subject to aging effects from radiation, heat, or moisture. The only insulated cables excluded from this program are those covered by the Environmental Qualification Program. The Insulated Cables Aging Management Program identifies inspections, parameters to be monitored, and corrective actions to be taken in accordance with the requirements of 10 CFR Part 50, Appendix B. We concur with the staff's conclusion that this comprehensive program resolves this open item.

A number of SER open items involved reactor vessel internal components. Aging effects to be addressed included changes in dimensions due to void swelling, cracking in reactor vessel internal noncast austenitic stainless steel components, cracking of baffle-former bolts, embrittlement of cast austenitic stainless steel components, thermal embrittlement of vent valves, and reduction in fracture toughness. Duke has addressed these open items in the Oconee Reactor Vessel Internals Aging Management Program (RVIAMP). This program includes participation in industry initiatives to investigate these aging effects, inspections, and reports to be provided to the NRC on a periodic basis. A final report will be submitted by Duke to the NRC near the end of the initial license period for Unit 1. The final report will contain the test results from the Babcock & Wilcox Owners Group's RVIAMP and the recommended inspection program for Oconee. On the basis of this information, Duke will implement an aging management program for the reactor vessel internals. We find the proposed program comprehensive and adequate for resolving the reactor vessel internals open items.

Duke committed to implementing a plant-specific fatigue monitoring program in which it will use correlations published in NUREG/CR-5704 to calculate environmental penalties at the high fatigue-usage locations identified in NUREG/CR-6260 to assess the effects of the reactor coolant environment on the fatigue life of components and piping. The correlations reflect data developed to resolve Generic Safety Issue (GSI) 190, "Fatigue Evaluation of Metal Components for 60-Year Plant Life." We concur with the staff's conclusion that Duke's proposed program is an acceptable plant-specific approach for resolving GSI-190 concerns.

The Oconee license renewal application described the process and the results of a time-limited aging analysis to demonstrate the adequacy of prestressing forces in the containment post-tensioning tendons during the period of extended operation. The staff requested additional information needed to support this demonstration. Duke has responded by proposing a Post-Tensioning System Loss of Prestress Aging Management Program to identify and correct degradation of the post-tensioning system prior to an unacceptable loss of prestress. This program implements the requirements of the American Society of Mechanical Engineers (ASME) Code Section XI, Subsection IWL, for in-service inspection, trending, and repair or replacement activities of the post-tensioning systems of concrete containments. We concur with the staff's assessment that the implementation of this program adequately resolves this open item.

As Oconee Units 1, 2 and 3 age, inspection and operating experience may prompt significant adjustments to their aging management programs. Duke has committed to document in the FSAR Supplement that all components subject to an aging management program fall under the requirements of its Problem Investigation Process corrective action program. Furthermore, the staff has required that Duke include in the Oconee FSAR the license renewal application commitments that the staff relied upon to conclude that aging effects will be adequately managed for the period of extended operation. These steps ensure that future changes to the aging management programs can be controlled under the 10 CFR 50.59 process.

The staff has performed a comprehensive and thorough review of Duke's application. The additional programs required by the staff are appropriate and sufficient. Current regulatory requirements and existing Duke programs provide adequate management of aging-induced degradation for those SSCs within the scope of the license renewal rule.

Mr. John D. Sieber did not participate in the Committee's deliberations regarding this matter.

Dr. William J. Shack did not participate in the Committee's deliberations regarding aging-induced degradation.

Sincerely,

Signed by

Dana A. Powers
Chairman

References:

1. Letter dated February 3, 2000, from David B. Matthews, Office of Nuclear Reactor Regulation, to William R. McCollum, Jr., Duke Energy Corporation, Subject: Final Safety Evaluation Report.
2. ACRS letter dated September 13, 1999, from Dana A. Powers, Chairman, ACRS, to William D. Travers, Executive Director for Operations, NRC, Subject: Interim Letter Related to the License Renewal of Oconee Nuclear Station.
3. Letter dated June 16, 1999, from David B. Mathews, Office of Nuclear Reactor Regulation, to William R. McCollum, Jr., Duke Energy Corporation, Subject: Oconee Nuclear Station, Units 1, 2 and 3, License Renewal Safety Evaluation Report.
4. Letter dated April 26, 1999, from Christopher I. Grimes, Office of Nuclear Reactor Regulation, to David J. Firth, B&W Owners Group, Subject: Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled, "Demonstration of the Management of Aging Effects for the Reactor Vessel," BAW-2251, June 1996.
5. Letter dated June 27, 1996, from D. K. Croneberger, B&W Owners Group, to Document Control Desk, NRC, Subject: Submittal of BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," June 1996.
6. U. S. Nuclear Regulatory Commission, Office of Nuclear Reactor Regulation Office Letter Transmittal No. 805, "License Renewal Application Review Process," June 19, 1998.
7. U. S. Nuclear Regulatory Commission Safety Evaluation Report (SER) related to the Babcock & Wilcox (BAW) Topical Report 2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," April 26, 1999.

8. U. S. Nuclear Regulatory Commission, NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999.
9. U. S. Nuclear Regulatory Commission, NUREG/CR-6260, "Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components," March 1995.

6 CONCLUSIONS

The staff reviewed the license renewal application for the Oconee Nuclear Station (ONS) in accordance with Federal regulations and the NRC draft "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants," dated September 1997. The standards for issuance of a renewed license are set forth in 10 CFR 54.29.

In the safety evaluation report (SER) issued on June 16, 1999, the staff identified a number of open and confirmatory items. All of those items have been resolved, as discussed in this SER. On the basis of its evaluation of the application as discussed above, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require an aging management review under 10 CFR 54.21(a)(1), and (2) actions have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the current licensing basis for the ONS, Unit Nos. 1, 2, and 3. The staff notes that the results of the staff's environmental review are documented in the final plant-specific supplement to the Generic Environmental Impact Statement.

APPENDIX A
CHRONOLOGY

This appendix contains a chronological listing of routine licensing correspondence between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke Energy Corporation and other correspondence regarding the NRC staff's review of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3 (under Docket Nos. 50-269, 50-270, and 50-287, respectively) application for license renewal. The documents listed prior to November 1, 1999, have a microfiche address associated with them. On November 1, 1999, the NRC discontinued processing documents and producing microfiche through the Nuclear Documents System (NUDOCS). The information after November 1, 1999, is available on the Agency wide Documents Access and Management System (ADAMS). In addition, the publicly available data records and full text documents that reside in NUDOCS will eventually be transferred to the external ADAMS Web Site's Legacy Library.

March 1, 2000	Letter (signed by J. Sebrosky) Oconee Nuclear Station (ONS) draft updated final safety analysis report (UFSAR) supplement. ACN: ML003687486
February 17, 2000	Letter (signed by J. Sebrosky) Form and content of renewed licenses for Oconee Nuclear Sation, Unit Nos. 1, 2 and 3. ACN: ML003684640
February 17, 2000	Forthcoming meeting with Duke Energy Corporation to discuss form and content of the renewed licenses for Oconee Nuclear Station Units 1, 2 and 3. ACN: ML003684739
February 14, 2000	Forthcoming meeting with Duke Energy Corporation on license renewal for Oconee Nuclear Station Units 1, 2 and 3. ACN: ML003683347
February 4, 2000	Memorandum (signed by J. Sebrosky) summary of September 29, 1999, meeting with Baltimore Gas and Electric (BGE) and Duke Energy Corporation (Duke) regarding license renewal activities for Calvert Cliffs Nuclear Power Plant (CCNPP) and Oconee Nuclear Station. ACN: ML003681013
February 3, 2000	Memorandum (signed by J. Sebrosky) handouts from January 18, 2000, meeting with BGE and Duke regarding license renewal activities for CCNPP and ONS. ACN ML003676902

February 3, 2000	Letter to Advisory Committee on Reactor Safeguards (signed by J. Sebrosky) transmitting 12 copies of the Oconee Nuclear Station license renewal Safety Evaluation Report (SER) and providing a roadmap of the changes to the SER from the June 1999 version ACN: ML003680217
February 3, 2000	Letter (signed by D. Matthews) Oconee Final Safety Evaluation Report license renewal application. ACN: ML003680364
February 3, 2000	Memorandum (signed by J. Sebrosky) summary of January 18, 2000, meeting with BGE and DUKE regarding license renewal activities for CCNPP and ONS. ACN: ML003680391
January 31, 2000	Memorandum (signed by J. Sebrosky) summary of January 27, 2000, phone call between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives to discuss piping issues related to the ONS license renewal application (LRA). ACN: ML003679039
January 14, 2000	Memorandum (signed by J. Sebrosky) summary of January 10, 2000, phone call between the U.S. Nuclear Regulatory (NRC) staff and Duke representatives to discuss insulated cables related to the Oconee License Renewal Application (LRA) ACN: ML003675493
January 12, 2000	Letter (from M. Tuckman) license renewal response to NRC letter dated December 14, 1999 regarding Comment 3 of the SER Open Item 3.9.3-1, regarding insulated cables for renewed operating licenses for Oconee Nuclear Station, Units 1, 2, and 3. ACN: ML003677133
January 7, 2000	Letter (from M. Tuckman) License Renewal Response to NRC Letter dated December 14,1999, regarding the Oconee Nuclear Station (ONS) ACN: ML003677136
January 6, 2000	Meeting summary of January 4, 2000 phone call between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives to discuss the reactor vessel internals inspection (RVII) and reactor vessel internals aging management programs (RVIAMP) ACN: ML003672241
January 4, 2000	Letter (from J. Sebrosky) open issue related to aging effects of insulated cables for the Oconee Nuclear Station, Units 1, 2, and 3 license renewal application. ACN: ML003671379

December 21, 1999	Memorandum (signed by: J. Sebrosky) providing list of the Duke-provided drawings that were used by staff as an aid in the evaluation of the added systems structures and components. ACN: ML993570128
December 17, 1999	Letter (from M. Tuckman) response to NRC November 18, 1999, letter regarding Duke Energy Corporation July 6, 1998, application for renewed operating licenses for Oconee Nuclear Station, Units 1, 2 and 3. ACN: ML993620451
December 14, 1999	Letter (from C. I. Grimes) request for information related to the design of the Oconee borated water systems. ACN: ML993550339
December 14, 1999	Memorandum (from J. Sebrosky) summary of meeting between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding open issues for the Oconee license renewal application (LRA). ACN: ML993550437
December 10, 1999	Memorandum (from J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding a September 30, 1999, submittal from Duke for the Oconee license renewal application (LRA). ACN: ML993500423
December 10, 1999	Meeting summary of November 10, 1999, phone call between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives to discuss the secondary shield wall related to the Oconee license renewal application. ACN: ML993500075
December 10, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the NRC staff and Duke representatives regarding SER Open Item 3.1.1-1 related to the Oconee license renewal application. ACN: ML993490275
December 10, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory commission (NRC) staff and Duke representatives to discuss materials related issues regarding the Oconee license renewal application (LRA) ACN: ML993490238
November 30, 1999	Letter (from M. Tuckman) response to NRC letter dated October 8, 1999 related to the scoping issue for license renewal of ONS Units 1, 2, and 3 ACN: ML993440076
November 24, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and DUKE

	representatives regarding mechanical systems associated with the Oconee license renewal application (LRA) ACN: ML993350082
November 24, 1999	Forthcoming December 9, 1999, meeting with Duke Energy Corporation (DUKE) on license renewal for Oconee Nuclear Station (ONS), Units 1, 2 and 3. ACN: ML993340444
November 23, 1999	Forthcoming December 9, 1999, meeting with Baltimore Gas and Electric Company (BGE) and Duke Energy Corporation (DUKE) on license renewal for Calvert Cliffs Nuclear Power Plant (CCNPP). Unit 1 and 2 and Oconee Nuclear Station. ACN: ML9933340439
November 18, 1999	Letter (from J. Sebrosky) status of open and confirmatory items from June 16, 1999, safety evaluation report for Duke's license renewal application for Oconee Unit Nos. 1, 2 and 3. ACN: ML993330363
November 18, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives to discuss the Oconee license renewal application. ACN: ML993330354
November 18, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding insulated cables associated with the Oconee license renewal. ACN: ML993330348
November 18, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding additional systems, structures and components added to the Oconee license renewal application (LRA). ACN: ML993330342
November 18, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding additional systems, structures and components added to the Oconee license renewal application (LRA). ACN: ML993330334
November 18, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding containment tendon trend lines for the Oconee license renewal application (LRA). ACN: ML993330330

November 5, 1999	Memorandum (signed by: J. Sebrosky) summary of discussions between the NRC staff and Duke representatives regarding the chilled water system for the Oconee license renewal application (LRA) ACN: ML993240203
November 4, 1999	Memorandum (signed by: J. Sebrosky) summary of meeting between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives regarding scoping for the Oconee license renewal application ACN: ML993240223
November 2, 1999	Meeting summary of October 13, phone call between the U.S. Nuclear Regulatory Commission (NRC) staff and Duke representatives to discuss the Oconee license renewal application. ACN: ML993200145
November 1, 1999	Letter (from R. L. Gill) submitting response to questions regarding safety evaluation report open item 2.2.3.4.3.2.1-1. ACN: ML993240213
October 27, 1999	NRC letter (from C. Grimes) informs Duke that NRC will not be able to issue final safety evaluation for BAW-2248 until mid-November because of scheduler conflicts & workload priorities. ACN: 9910290367 FICHE: A9714:282-A9714:288
October 15, 1999	NRC letter (from M. S. Tuckman) forwarding comments on safety evaluation report for Oconee Nuclear Station license renewal application dated July 6, 1999. Response to open item & confirmatory items included. ACN: 9910260253 FICHE: A9663:001-A9663:140
October 15, 1999	Memorandum (signed by: J. Sebrosky) forwards Duke editorial comments on June 1996 SER related to license renewal application of Oconee Nuclear Station units 1 2 and 3. Duke intends to provide additional comments on SER of more substantial nature in separate letter. ACN: 9910220085 FICHE: A9600:001-A9601:094
October 13, 1999	Memorandum (signed by: J. Sebrosky) notification of October 28, 1999, meeting with Duke in Rockville, Maryland, to discuss scoping process used for Oconee Nuclear Station license renewal application. ACN: 9910180202 FICHE: A9555:358-A9555:360
October 8, 1999	Memorandum (signed by: W. Travers) discusses interim letter on license renewal of Oconee Nuclear Station staff will inform committee at earliest possible time about resolution of specific open & confirmatory items for Oconee renewal application. ACN: 9910150189 FICHE: A9534:325-A9534:334

October 8, 1999	NRC letter (from C. I. Grimes) provides NRC staff plan for resolving Open Item 2.1.3.1-1 of safety evaluation report regarding license renewal of plant Units 1, 2 and 3. ACN: 9910140134 FICHE: A9530:260-A9530:267
October 7, 1999	Memorandum (signed by: S. Koenick) nonfiction of October 28, 1999, meeting with BG&E & Duke Energy Corp in Rockville, Maryland to discuss status of review of BG&E Duke license renewal application for CCNPP Units 1 & 2 & ONS Units 1 2 &3. ACN: 9910130276 FICHE: A9485:160-A9485:163
October 5, 1999	NRC Letter (from C. Grimes) requests additional information regarding aging effects of insulated cables and connections for plant based on inspection findings noted in inspection reports 50-269-99-12, 50-270-99-12 & 50-287-99-12 and license renewal application. ACN: 9910070216 FICHE: A9457:149-A9457:153
September 30, 1999	Letter (from M. S. Tuckman) forwards Amend 1 to July 6, 1998, application for renewal of licenses DPR-38, DPR-47 and DPR-55 containing summary descriptions of listed changes to current licensing basis that materially effect contents of application ACN: 9910120195 FICHE: A9549:290-A9549:321
September 29, 1999	Meeting summary of August 20, 1999 meeting with BGE & Duke in Rockville, Maryland to discuss Open Item 3.0-1 in BGE & Duke Safety Evaluation Report written by staff for their respective license renewal applications with attendance list meeting slides and handout. ACN: 9910050005 FICHE: A9418:287-A9418:303
September 21, 1999	Letter from (V. M. McCree) forwards inspection reports 50-269-99-12, 50-270-99-12& 50-287-99-12 on 990602-0730. No violations noted. Inspection revealed that in most cases existing aging management programs implemented as described in licensee application. ACN: 9910080191 FICHE: A9464:046-A96464:099
September 15, 1999	Memorandum (from J. Sebrosky) notification of September 29, 1999 meeting with utilities in Rockville Maryland to discuss status of review of BGE & Duke licensing renewal applications for Calvert Cliffs Units 1, 2 and Oconee Nuclear Station Units 1, 2 and 3. ACN: 9909200202 FICHE: A9235:291-A9235:294
September 15, 1999	Memorandum (from J. Sebrosky) notification of September 29, 1999 meeting with DUKE Energy Corp in Rockville, Maryland, to discuss issues associated with reactor vessel internals for Oconee License Renewal application agenda for meeting also enclosed. ACN: 9909200186 FICHE: A9235:279-A9235:282

September 13, 1999 Memorandum (from D. A. Powers) informs that during 465th meeting of ACRS on 990901-03 committee reviewed NRC staff SER re license renewal of Oconee Nuclear Station Units 1, 2 & 3 conclusions recommendations listed.
ACN: 9909240222 FICHE: A9382:318-A9382:322

September 9, 1999 Meeting summary of August 25, 1999, meeting with Duke in Rockville, Maryland, regarding issues associated with fatigue for LRA for Oconee Units 1, 2 and 3. List of meeting attendees and Duke proposed responses enclose.
ACN: 9909140168 FICHE: A9193:249-A9193:265

September 9, 1999 Meeting summary of August 24, 1999 meeting with utility regarding cast austenitic stainless steel for plant license renewal application. List of attendees and slides used at meeting enclose.
ACN: 9909130160 FICHE: A9192:341-A9192:358

September 9, 1999 Memorandum (from J. Sebrosky) forwards preliminary responses from Duke to open and confirmation items associated with Safety Evaluation report for Oconee license renewal application.
ACN: 9909100179 FICHE: A9179:103-A9179:126

September 7, 1999 Meeting summary August 27, 1999, meeting with utilities in Rockville, Maryland, to discuss status of NRC review of utilities license renewal application for plants units. List of attendees meeting summary and slides provided.
ACN: 9909140026 FICHE: A9193:170-A9193:248

August 27, 1999 Meeting summary of August 18, 1999 meeting with utilities in Seneca SC regarding 10 CFR 54.4 scoping for Oconee Nuclear Station Unit Nos. 1, 2 and 3. List of meeting attendees and background material and agenda for staff review enclosed.
ACN: 9908310171 FICHE: A9086:323-A9086:345

August 19, 1999 Meeting summary of July 28, 1999 meeting with BG&E and Duke in Rockville, Maryland, regarding status of NRC review of BG&E and Duke license renewal applications for CCNPP Units 1, 2 and ONS Units 1, 2 and 3. List of meeting attendees and presentation slides enclosed.
ACN: 9908230172 FICHE: A9005:268-A9005:310

August 12, 1999 Meeting notice of August 27, 1999 meeting with BGE & Duke in Rockville, Maryland, regarding status of review of BGE and Duke license renewal applications for plants.
ACN: 9908160111 FICHE: A8965:276-A8965:279

August 9, 1999 Meeting notice of August 9, 1999 meeting with Duke Energy Corporation in Rockville, Maryland, to discuss issues associated with fatigue related to

	Oconee license renewal SER. Staff expects to discuss issues associated with generic safety issue 190. ACN: 9908110206 FICHE: A8913:059-A8913:061
August 6, 1999	Meeting notice of August 18, 1999 meeting with utility in Seneca SC to review material associated with scoping process used for license renewal application for plant units 1, 2 and 3. ACN: 9908110002 FICHE: A8913:135-A8913:140
July 14, 1999	Meeting notice of July 28, 1999 meeting with utility in Rockville, Maryland, to discuss status of review of BG&E & Duke license renewal applications for CCNPP Units 1, 2 and ONS Units 1, 2, and 3 respectively. ACN: 9907190107 FICHE: A8606:325-A8606:328
July 1, 1999	Meeting summary of June 30, 1999 meeting with licensees in Rockville, Maryland, regarding license renewal activities attendance list and slides enclosed meeting will be held in Rockville, Maryland, meeting attendees enclosed. ACN: 9907120009 FICHE: A8511:056-A8511:069
June 23, 1999	NRC letter (from J. Sebrosky) refers to Oconee license renewal SER sent on June 16, 1999, informs that number of copies were missing pages 3-173 and 3-185 forwards new pages 3-173 through 3-186 that should replace existing pages 3-174 through 3-186. ACN: 9906290115 FICHE: A8466:216-A8466:232
June 22, 1999	Letter (from M. S. Tuckman) submits response to license renewal safety evaluation report Open Item 2.1.3.1-1 for plant per May 11, 1999, meeting. Information provided on scoping events set used for license renewal mechanical systems scoping. ACN: 9907010304 FICHE: A8511:056-A8511:069
June 16, 1999	NRC letter (from D. Matthews) forwards safety evaluation report regarding licensee's July 6, 1998, application to NRC for renewal of Oconee Nuclear Station Units 1, 2 and 3 operating license for additional 20 years. Open items must be resolved before NRC can make final determination on application ACN: 9906210071 FICHE: A8374:001-A8375:137
June 15, 1999	Letter (from V. McCree) discusses May 26, 1999 meeting regarding results of 1st Oconee license renewal inspection. Forwards list of attendees and presentation slide. ACN:9906220192 FICHE: A8382:191-A8382:197
June 14, 1999	Meeting notice of June 30, 1999 meeting with BG&E and Duke in Rockville, Maryland, to discuss status of review of BG&E and Duke license renewal applications for CCNPP Units 1and 2 and ONS Units 1, 2 and 3 respectively. ACN: 9906160165 FICHE: A8352:298-A8352:302

June 2, 1999	Meeting summary (signed by J. Sebrosky) of May 27, 1999 and June 2, 1999, telcons with Duke representatives regarding Oconee license renewal application. ACN: 9906070202 FICHE: A8213:267-A8213:276
May 24, 1999	Inspection Reports 5O-269-99-11 50-270-99-11 & 50-287-99-11 on 990426-30 no violations noted major areas inspected samples of plant equipment and documentation that supported DUKE energy application for renewed operating licenses. ACN: 9906030281 FICHE: A8211:194-A8211:219
May 24, 1999	NRC letter (signed by V. McCree) inspection reports 50-269/99-11, 50-270/99-11, and 50-287/99-11 for April 26, 1999, through April 30, 1999, inspection. Purpose of the inspection was to examine a sample of plant equipment and the documentation that support the Oconee Nuclear Station license renewal application. ACN: 9906030281
May 19, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of May 11, 1999 meeting with NRC and Duke Energy Corporation to discuss status of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9905210124 Fiche: A8107:223-A8107:240
May 17, 1999	Meeting summary of March 30, 1999 meeting with NEI to discuss status of first two license renewal application resolution of license renewal issues and establishing position RE credit for existing programs list of attendees enclosed ACN: 9905240279 FICHE: A8119:336-A8119:350
May 13, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of May 12, 1999 meeting with Duke in Rockville, Maryland regarding Oconee license renewal application. ACN: 9905170206 Fiche: A7994:001-A7994:015
May 12, 1999	NRC letter (signed by B. Mallet) discussed April 21, 1999 meeting conducted by NRC regarding the analysis methodology supporting Oconee license renewal. ACN: 9905250183 Fiche: A8132:195-A8132:263
May 10, 1999	NRC letter (signed by V. McCree) confirming telcon between J. Burchfield and C. Julian regarding meeting to be conducted on May 26, 1999 for NRC to present results of its first inspection of the implementation of the Oconee license renewal program. ACN: 9905190144 Fiche: A8087:173- A8087:248

May 10, 1999	Letter from Duke Energy Corporation (signed by M. Tuckman) forwarding responses to RAI regarding review of application for renewal of licenses DPR-38, DPR-47, and DPR-55 (Open Item 3.4.5-9) ACN: 9905170143
May 10, 1999	Letter (M. Tuckman) forwards responses to RAI RE review of July 6, 1998 application for renewal of licenses DPR-38 DPR-47 and DPR-55 response to potential Open Item 3.4.5-9 contains license renewal applicant items listed in SER submitted on April 26, 1999. ACN: 9905170143 FICHE: A8087:173-A8087:248
April 27, 1999	Meeting notice of May 12, 1999 meeting with Duke Energy Corporation to discuss status of review of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3 ACN: 9904300019 Fiche: A7837:354-A7837:356
April 26, 1999	NRC letter (signed by C. Grimes) informing that effective immediately NRC project management responsibility for Oconee nuclear station license renewal application assigned to J. Sebrosky. ACN: 9904280209 Fiche: A7831:218-A7831:220
April 21, 1999	Letter (signed by R. Gandy) informs that Oconee nuclear station has been assigned NPDES permit number SC0000515 in response to NRC request. Resolution of toxicity testing issues and public comment period must be completed before issuance of permit. ACN: 9904280121 Fiche: A7837:314-A7837:315
April 19, 1999	Letter from Duke Energy Corporation (signed by M. Tuckman) forwarding proprietary and non-proprietary response to NRC March 17, 1999 RAI regarding TR DPC-NE-3005-P which describes new methodology for analyzing Oconee UFSAR Chapter 15 non-LOCA transients and accidents. ACN: 9904270125 Fiche: A7851:327-A7851:355
April 16, 1999	NRC letter (signed by J. Sebrosky) discussing potential SER open items regarding review of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Aim of process is to minimize amount of SER open items without impacting schedule for issuing SER. ACN: 9904220149 Fiche: A7757:304-A7757:314
April 15, 1999	Memorandum and order (signed by A. Vietti-Cook) ordering that petitioner's appeal of board ruling be denied. The Commission affirms LBP-98-33 in entirety. ACN: 9904160064 Fiche: A7645:181-A7645:207

April 15, 1999	Meeting notice of May 11, 1999 meeting with Duke Energy Corporation to discuss scoping process used for Duke license renewal application for Oconee Nuclear Station, Units 1, 2, and 3. ACN: 9904200234 Fiche: A7667:183-A7667:187
April 13, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of April 1, 1999 telcon between NRC and Duke in Rockville, Maryland to discuss questions that staff had regarding fire protection. ACN: 9904160231 Fiche: A7631:107-A7631:113
April 12, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) informing that Duke intends to submit single amendment to plant application for renewed operating licenses dated 980706 on or about 990930 to comply with 10 CFR 54.21 requirements to report changes to licensing basis in listed manner. Fiche: A7776:357-A7776:360
April 8, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of April 1, 1999 telcon with NRC staff and Duke representatives to discuss Duke response to RAI 3.4.11-7. ACN: 9904140129 Fiche: A7608:310-A7608:312
April 8, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of March 15, 1999 telcon between NRC and Duke representatives to discuss question staff had regarding environmental qualifications concerning difference between BGE license renewal application and Duke application. ACN: 9904140126 Fiche: A7608:303-A7608:309
April 8, 1999	NRC letter (signed by J. Sebrosky) discussing potential SER open items regarding review of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3 ACN: 9904160008 Fiche: A7631:249-A7631:269
April 7, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of March 15, 1999 and March 23, 1999 telcons between Duke and NRC regarding Oconee license renewal application and questions the staff had regarding application. ACN: 9904120115 Fiche: A7577:340-A7577:348
April 7, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of March 30, 1999 meeting with Duke Energy Corporation regarding Oconee license renewal application. ACN: 9904090252 Fiche: A7514:001-A7514:017
April 6, 1999	Letter (signed by H. Ildari) forwarding license and amendments explaining filing requirements for FERC project 2503 as requested in March 1, 1999 letter. ACN: 9904190147 Fiche: A7734:238-A7734:289

April 6, 1999	Letter from Duke Energy Corporation (signed by M. Tuckman) forwarding revised responses to NRC RAI regarding application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9904140327 Fiche: A7677:238-A7677:245
April 6, 1999	NRC letter (signed by C. Ogle) summarizing April 2, 1999 telcon between regarding meeting to be conducted on April 21, 1999 at Oconee nuclear station regarding Duke analysis methodology that supports the license renewal application. ACN: 9904130307 Fiche: A7620:147-A7620:149
April 2, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of March 11, 1999 meeting with Duke in Rockville, Maryland regarding Oconee license renewal application and scoping process used by Duke to comply with 10 CFR 4.4. ACN: 9904070403 Fiche: A7487:001-A7487:016
March 31, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding response to NRC January 5, 1999 RAI concerning Oconee IPEEE analysis. ACN: 9904070097 Fiche: A7556:003-A7556:134
March 30, 1999	NRC memorandum (signed by L. Reyes) forwarding final version of license renewal inspection plan for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9904060290 Fiche: A7489:001-A7489:021
March 29, 1999	Letter from Duke Energy Corporation (signed by M. Tuckman) forwarding supplemental response to NRC RAI 5.4.1-5 to provide additional information on Oconee thermal fatigue management program and topics discussed in March 18, 1999 telcon. ACN: 9904050090 Fiche: A7532:350-A7532:361
March 26, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of March 15, 1999 phone call with Duke in Rockville, Maryland regarding Oconee license renewal application and to discuss Duke response to RAI 3.5.6-2. Fiche: A7450:133-A7450:135
March 26, 1999	NRC letter (signed by J. Sebrosky) summary of March 4, 1999 phone call with Duke in Rockville, Maryland regarding Oconee license renewal application and licensee response to RAI 4.26-1.
March 18, 1999	Letter from Duke Energy Corporation forwarding revised response to RAI regarding application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Confirms that response to RAI 2.6.1-1 is correct as written and that regardless of terminology used to identify functions, there is no impact on results. ACN: 9903260236 Fiche: A7450:130-A7450:132

March 17, 1999	Meeting notice of March 30, 1999 meeting with Duke Energy Corporation to discuss status of review of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9903230097 Fiche: A7323:294-A7323:296
March 15, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding correction to 980618 RAI on Oconee emergency power system. ACN: 9903250197 Fiche: A7428:194-A7428:197
March 10, 1999	Meeting notice of March 11, 1999 meeting with Duke Energy Corporation to discuss scoping process used for application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Notice was reissued to change date and place of meeting. ACN: 9903170028 Fiche: A7239:346-A7239:348
March 5, 1999	NRC letter (signed by J. Sebrosky) forwarding summary of February 26, 1999 meeting with Duke in Rockville, Maryland regarding application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Fiche: A7163:040-A7163:056
March 4, 1999	Memorandum (signed by A. Vietti-Cook) notifying Commission that proposed rule regarding environmental impacts of transportation of high-level waste was published in February 26, 1999 *Federal Register* Notice. ACN: 9903080042 Fiche: A7089:300-A7089:305
March 3, 1999	NRC letter (from J. Sebrosky) forwarding summary of February 26, 1999 meeting in Rockville, Maryland regarding Oconee license renewal application. ACN: 9903110233 Fiche: A7163:040-A7163:056
March 1, 1999	Meeting notice of March 10, 1999 meeting with Duke Energy Corporation in Rockville, Maryland to discuss scoping process used for the Oconee license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9903080123 Fiche: A7060:351-A7060:353
February 17, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding responses to RAIs regarding license renewal for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9902240291 Fiche: A6985:001-A6985:257
February 16, 1999	Meeting notice of February 26, 1999 meeting with Duke Energy Corporation to discuss status of the review of the license renewal application for Oconee Nuclear Station, Unit Nos. 1,2, and 3. ACN: 9902190342 Fiche: A6889:066-A6889:068

February 12, 1999	Meeting notice of January 19, 1999 meeting in Rockville, Maryland to discuss status of review of Duke Energy Corporation's license renewal application. ACN: 9902180229 Fiche: A6889:021-A6889:023
February 8, 1999	NRC letter (from C. Grimes) forwarding trip report of October 27, 1998 visit to Duke Energy Corporation office in Charlotte, North Carolina to review license renewal scoping and screening methodology and justification for Oconee Nuclear Station license renewal application. ACN: 9902110301 Fiche: A6801:330-A6801:337
February 8, 1999	Submittal from Duke Energy Corporation forwarding drawing with regard to the Oconee Nuclear Station site plan structures within scope of license renewal. ACN: 9902260269 Fiche: 38260:001-38260:001
February 8, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding responses to NRC RAIs regarding application for renewal of licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9902180172 Fiche: A6960:154-A6960:259
February 2, 1999	NRC letter (from J. Sebrosky) forwarding summary of January 26, 1999 telephone call with Duke Energy Corporation's representative regarding Oconee license renewal application and timing of new inspections to verify presence or absence of various degradation mechanisms specific to certain components. ACN: 9902090112 Fiche: A6783:330-A6783:334
January 31, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding the environmental impact statement scoping process summary report. ACN: 9901260312 Fiche: A6613:299-A6613:314
January 28, 1999	NRC letter (signed by the Chairman) discussing license renewal for operating power reactors. Two applications have been received for renewing operating licenses. The Commission has established an adjudicatory schedule aimed at completing the license renewal process in 30 – 36 months. ACN: 9902090060 Fiche: A6789:342-A6789:345
January 28, 1999	NRC letter (from the Chairman) discussing guidance regarding license renewal for operating power reactors developed in response to FY99 Energy and Water Development Appropriations Act Report 105-581. ACN: 9902080222 Fiche: A6764:310-A6764:311

January 26, 1999	NRC letter (from J. Sebrosky) forwarding summary of January 14, 1999 meeting in Rockville, Maryland regarding Oconee license renewal application. ACN: 9901280361 Fiche: A6643:001-A6643:011
January 25, 1999	NRC brief in opposition to appeal of N. Williams, W. Clay, W. Lesan, and Chattooga River Watershed Coalition. Licensing board decision in LBP-98-33 should be affirmed. ACN: 9901270044 Fiche: A6650:108-A6650:135
January 25, 1999	Duke Energy Corporation brief (signed by D. Repka) in opposition to appeal of Chattooga River Watershed Coalition. ACN: 9901270036 Fiche: A6650:075-A6650:107
January 25, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding response to RAIs regarding application for renewed operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9902030243 Fiche: A6762:311-A6762:354
January 21, 1999	Summary of January 19, 1999 meeting in Rockville, Maryland regarding Oconee license renewal application regarding equipment qualification. ACN: 9901220365 Fiche: A6607:083-A6607:106
January 21, 1999	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding clarification of items with examination results that do not meet acceptance standards of IWL-3000. ACN: 9902020389 Fiche: A6742:329-A6742:331
January 20, 1999	Letter from Duke Energy Corporation (signed by M. Tuckman) forwarding affidavit for inclusion in December 14, 1998 response to October 29, 1998 RAI. ACN: 9902030244 Fiche: A6762:355-A6762:358
January 20, 1999	NRC letter (from J. Sebrosky) forwarding summary of January 14, 1999 telcon in Rockville, Maryland to discuss RAIs 3.4.5-4, 3.4.5-6, and 4.18-4 and how RAIs relate to B&W Topical Report 2251. ACN: 9901250258 Fiche: A6607:122-A6607:125
January 15, 1999	NRC letter (from J. Sebrosky) requesting clarification of response for November 19, 1998 RAI regarding review of the Oconee license renewal application. ACN: 9901250008 Fiche: A6607:260-A6607:262
January 14, 1999	Chattooga River Watershed Coalition brief (signed by B. Williams) in support of appeal of order denying intervention petition and dismissing proceeding. ACN: 9901200186 Fiche: A6556:260-A6556:265

January 14, 1999	Notice of appeal (signed by B. Williams) in which the Chattooga River Watershed Coalition files a notice of appeal to the Commission for review of ASLB December 30, 1998 memorandum and order denying petitioner petition for leave to intervene. ACN: 9901200180 Fiche: A6556:259-A6556:265
January 11, 1999	Meeting notice of January 19, 1999 meeting in Rockville, Maryland to discuss how Duke Energy Corporation will respond to RAIs 5.6-1, 5.6-2, and 5.6-3 in the environmental qualification area. ACN: 9901130214 Fiche: A6523:314-A6523:316
January 11, 1999	NRC letter (from J. Sebrosky) forwarding summary of December 16, 1998 meeting in Rockville, Maryland regarding Oconee license renewal application. ACN: 9901130206 Fiche: A6523:228-A6523:251
January 11, 1999	NRC letter (from J. Sebrosky) forwarding RAI tracking system for Oconee license renewal application. ACN: 9901120055 Fiche: A6495:158-A6495:211
January 7, 1999	Response (signed by E. Julian) to message to S. Marks regarding information request on appeal deadline and desire to serve appeal either by e-mail or by alternative regular mail. ACN: 9901120030 Fiche: A6518:075-A6518:076
January 7, 1999	Response (signed by A. Vietti-Cook) to December 17, 1998 letter to the Chairman regarding issues for consideration by the Commission during Oconee license renewal process. The Commissioners must remain impartial during pendency of case. ACN: 9901080020 Fiche: A6507:111-A6507:121
January 4, 1999	Meeting notice (signed by J. Sebrosky) of January 14, 1999 meeting in Rockville, Maryland to discuss status of review of Oconee license renewal application. ACN: 9901080041 Fiche: A6474:117-A6474:119
December 29, 1998	Memorandum and order (signed by B. Cotter) denying petition to intervene because proffered contentions failed to meet requirements for admissibility. ACN: 9901040021 Fiche: A6419:306-A6419:332
December 22, 1998	NRC staff response (signed by M. Zobler) to petitioner's new information stating that information provided by petitioners is not new, and does not support proposed contentions. ACN: 9812230050 Fiche: A6323:297-A6323:303

December 21, 1998	Duke Energy Corporation response (signed by D. Repka) to new information submitted by Chattooga River Watershed Coalition in support of processed contentions. ACN: 9812230037 Fiche: A6323:316-A6323:326
December 17, 1998	Letter (from F. Hollings) expressing concerns regarding license renewal of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Commends NRC on the steps the agency has undertaken to conclude renewal process. ACN: 9901080024 Fiche: A6507:118-A6507:121
December 14, 1998	Letter from Duke Energy Corporation forwarding responses to NRC October 29, 1998 RAIs regarding Sections 3.4.11, 3.5.9, 4.3.2, 4.3.8, 4.6.2, 4.6.3, 4.6.4, 4.21, and 5.7.1 of July 6, 1998 application. ACN: 9812230258 Fiche: A6348:131-A6348:182
December 14, 1998	Order (signed by B. Cotter) granting requests from staff and applicant to file responses to petitioner filing of December 9, 1998. ACN: 9812160031 Fiche: A6225:207-A6225:209
December 11, 1998	Duke Energy Corporation motion (signed by D. Repka) for leave to respond to new information submitted by Chattooga River Watershed Coalition. ACN: 9812160087 Fiche: A6225:198-A6225:202
December 11, 1998	NRC staff motion (signed by M. Zobler) for leave to respond to petitioner filing. ACN: 9812160039 Fiche: A6225:210-A6225:213
December 9, 1998	Petitioner's response (signed by N. Williams) to ASLB RAI, providing new information for ASLB to consider with petitioner's first supplemental filing. ACN: 9812160016 Fiche: A6225:262-A6225:265
December 9, 1998	Duke Energy Corporation response (signed by D. Repka) to licensing board order requesting information concerning high-level radioactive waste transportation rulemaking. ACN: 9812110069 Fiche: A6127:339-A6127:352
December 4, 1998	NRC letter forwarding RAI concerning Section 4.16 of license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3,. ACN: 9812100091 Fiche: A6122:029-A6122:032
December 4, 1998	NRC letter (from J. Sebrosky) forwarding an RAI for review of Section 4.9 of July 6, 1998 license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812100054 Fiche: A6121:340-A6121:343

December 4, 1998	NRC letter (from J. Sebrosky) forwarding RAI regarding Oconee license renewal application. ACN: 9812100085 Fiche: A6122:033-A6122:036
December 3, 1998	NRC letter (from S. Hoffman) forwarding an RAI for review of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812100081 Fiche: A6121:344-A6121:347
December 3, 1998	NRC letter (from J. Sebrosky) forwarding RAI regarding Section 4.17 of license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812100071 Fiche: A6121:348-A6121:351
December 3, 1998	NRC letter (from J. Sebrosky) forwarding notification of December 16, 1998 meeting with Duke Energy Corporation in Rockville, Maryland to discuss status of review of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812080201 Fiche: A6078:207-A6078:209
December 3, 1998	NRC letter forwarding an RAI concerning Sections 3.4.7, 3.4.8, 3.4.9, 3.5.2, 3.5.3, 3.5.5, and 3.5.8 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812070290 Fiche: A6074:349-A6074:359
December 3, 1998	NRC letter (from J. Sebrosky) forwarding an RAI concerning Section 4.16 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812070286 Fiche: A6076:354-A6076:358
December 3, 1998	NRC letter (from J. Sebrosky) forwarding an RAI concerning Sections 5.1 and 5.2 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812070272 Fiche: A6077:309-A6077:312
December 2, 1998	NRC letter (from J. Sebrosky) forwarding RAI concerning Section 3.4.3 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812070185 Fiche: A6077:339-A6077:344
December 2, 1998	NRC letter (from J. Sebrosky) forwarding RAI concerning Section 2.2 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9812070182 Fiche: A6077:345-A6077:348
December 2, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Section 2.5.6 of the Oconee license renewal application. ACN: 9812070130 Fiche: A6077:352-A6077:357

December 2, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Section 4.23 of the Oconee license renewal application. ACN: 9812070077 Fiche: A6078:072-A6078:075
December 2, 1998	NRC staff response (signed by M. Zobler) to order requesting information regarding impacts of transportation of high level waste. ACN: 9812030022 Fiche: A6031:082-A6031:095
December 2, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Section 5.7.2 of the Oconee license renewal application. ACN: 9812070074 Fiche: A6078:083-A6078:086
December 1, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Sections 2.3, 2.5.3, 2.5.4, 2.5.10, and 4.9 of the Oconee license renewal application. ACN: 9812070068 Fiche: A6078:066-A6078:071
December 1, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Sections 2.0, 2.2, 2.6.1, 2.6.7, 2.7.1, and 4.13 of the Oconee license renewal application. ACN: 9812070082 Fiche: A6078:092-A6078:100
November 30, 1998	Letter from Duke Energy Corporation informing the NRC that it will complete design study and revisions to control room dose analyses in engineering calculations OSC-6810, OSC-6811, and OSC-6922 by May 1999. ACN: 9812080085 Fiche: A6115:303-A6115:306
November 30, 1998	NRC letter (from J. Sebrosky) forwarding an RAI to support the review of the Oconee license renewal application. ACN: 9812030131 Fiche: A6019:353-A6019:358
November 30, 1998	NRC letter forwarding an RAI regarding the Oconee license renewal application. ACN: 9812020322 Fiche: A6011:343-A6011:352
November 30, 1998	Affidavit of D. Cleary in response to licensing board questions regarding the environmental impacts of transportation of high level waste. ACN: 9812030024 Fiche: A6031:092-A6031:095
November 25, 1998	NRC letter (from S. Hoffman) forwarding an RAI concerning the Oconee license renewal application. ACN: 9812030021 Fiche: A6022:019-A6022:022
November 25, 1998	NRC letter (from S. Hoffman) forwarding an RAI regarding Sections 1.5.3, 2.6, 3.2, 3.6, and 5.6 of the Oconee license renewal application. ACN: 9812020204 Fiche: A6010:280-A6010:287

November 24, 1998	NRC letter (from S. Hoffman) forwarding RAI concerning the Oconee license renewal application. ACN: 9811300153 Fiche: A5991:326-A5991:331
November 20, 1998	NRC letter forwarding an RAI concerning Section 15.2 of the Oconee license renewal application. ACN: 9811250148 Fiche: A5974:337-A5974:340
November 20, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Section 3.5.8 of the Oconee license renewal application. ACN: 9811250141 Fiche: A5974:330-A5974:334
November 20, 1998	NRC letter (from J. Sebrosky) forwarding an RAI concerning Section 2.5.13 of the Oconee license renewal application. ACN: 9811250131 Fiche: A5963:289-A5963:293
November 20, 1998	NRC letter (from J. Sebrosky) forwarding an RAI regarding Sections 3.4.6 and 4.18 of the Oconee license renewal application. ACN: 9811250128 Fiche: A5963:233-A5963:237
November 20, 1998	NRC letter (from J. Sebrosky) forwarding an RAI concerning Sections 3.4.4 and 3.5.5 of the Oconee license renewal application. ACN: 9811250122 Fiche: A5963:304-A5963:307
November 20, 1998	NRC letter (from J. Sebrosky) forwarding RAI concerning Sections 3.4.5, 4.10, 4.3.1, 4.24, and 5.4.2 of the Oconee license renewal application. ACN: 9811250094 Fiche: A5974:307-A5974:313
November 20, 1998	NRC letter (from J. Sebrosky) forwarding concerning Sections 4.3.7, 4.22, and 5.4.2 of the Oconee license renewal application. ACN: 9811250120 Fiche: A5960:355-A5960:359
November 19, 1998	Order (signed by B. Cotter) requesting the staff to furnish listed information by December 2, 1998. ACN: 9811230027 Fiche: A5924:267-A5924:272
November 19, 1998	NRC letter (from J. Sebrosky) forwarding RAI regarding Sections 2.3, 3.3, 4.8, 5.3.1, and 5.3.2 of the Oconee license renewal application. ACN: 9811250136 Fiche: A5963:351-A5963:357
November 18, 1998	NRC letter (from J. Sebrosky) forwarding RAI concerning Sections 3.5.6, 3.5.7, and 3.5.13 of the license renewal application of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9811240166 Fiche: A5946:328-A5946:332
November 18, 1998	NRC letter (from J. Sebrosky) regarding Sections 3.7.2, 3.7.2-1, 4.21, and 4.21-6 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3, and forwarding general questions G-1, G-2, and G-3. ACN: 9811240164 Fiche: A5946:323-A5946:327

November 18, 1998 NRC letter (from J. Sebrosky) forwarding an RAI regarding Sections 3.7.4 and 4.15 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3.
ACN: 9811240135 Fiche: A5940:346-A5940:349

November 18, 1998 NRC letter (from J. Sebrosky) forwarding an RAI regarding Sections 3.4.7, 3.4.8, 3.4.10, 3.5.3, and 3.5.14 of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3.
ACN: 9811240127 Fiche: A5941:354-A5941:359

November 18, 1998 NRC letter (from J. Sebrosky) forwarding RAI concerning Sections 2.7, 3.7.1, 3.7.2, 3.7.5, 3.7.7, and 4.28 of the Oconee license renewal application.
ACN: 9811250042 Fiche: A5974:314-A5974:322

November 17, 1998 Meeting summary (signed by J. Sebrosky) of November 6, 1998 meeting with Duke Energy Corporation regarding fire protection portion of the Oconee license renewal application.
ACN: 9811200272 Fiche: A5928:304-A5928:308

November 16, 1998 NRC letter (from J. Sebrosky) forwarding summary of October 15, 1998 meeting with Duke Energy Corporation regarding overview of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3.
ACN: 9811240262 Fiche: A5947:026-A5947:086

November 16, 1998 NRC staff response (signed by M. Zobler) to petitioner first supplemental filing, stating that petitioners failed to submit admissible contention.
ACN: 9811170033 Fiche: A5836:001-A5836:048

November 16, 1998 Meeting summary (from J. Sebrosky) of October 22, 1998 meeting with Duke Energy Corporation in Rockville, Maryland regarding electrical scoping and screening process used in the Oconee license renewal application.
ACN: 9811200264 Fiche: A5928:309-A5928:315

November 16, 1998 Meeting summary (from J. Sebrosky) of October 29, 1998 meeting with representatives of Duke Energy Corporation in Rockville, Maryland to discuss the Oconee license renewal application.
ACN: 9811200013 Fiche: A5902:020-A5902:035

November 16, 1998 Response from Duke Energy Corporation (signed by J. McGarry) to supplemental petition to intervene filed by Chattooga River Watershed Coalition and N. Williams, W. Clay, and W. Lesan.
ACN: 9811180088 Fiche: A5854:013-A5854:045

November 13, 1998 NRC letter (from J. Sebrosky) forwarding an RAI regarding the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3.
ACN: 9811230245 Fiche: A5940:315-A5940:318

November 13, 1998	Meeting summary (from R. Anand) of September 15, 1998 meeting with the NEI license renewal task force in Rockville, Maryland regarding prioritization of generic license renewal issues for resolution. ACN: 9811190255 Fiche: A5892:297-A5892:342
November 12, 1998	NRC letter regarding Oconee license renewal application. The NRC is still reviewing information contained in the application and has not yet identified a need to request additional information. ACN: 9811170167 Fiche: A5840:285-A5840:287
November 6, 1998	NRC letter (from S. Hoffman) discussing NRC review of the Oconee license renewal application. ACN: 9811170134 Fiche: A5840:283-A5840:284
October 30, 1998	Petitioner's first supplemental filing (signed by N. Williams) requesting that the Chattooga River Watershed Coalition be admitted as a party to the Oconee Nuclear Station, Unit Nos. 1, 2, and 3 license renewal proceedings and that contentions be admitted for adjudication. ACN: 9811060042 Fiche: A5755:001-A5755:022
October 30, 1998	Meeting summary of October 1, 1998 meeting in Rockville, Maryland regarding license renewal scoping and screening process used in preparation of the Oconee license renewal application. ACN: 9811040238 Fiche: A5694:079-A5694:124
October 29, 1998	NRC letter (from J. Sebrosky) forwarding RAI regarding Sections 3.4.11, 3.5.9, 4.3.2, 4.3.8, 4.3.9, 4.6.2, 4.6.3, 4.6.4, 4.21, and 5.7.1 of the Oconee license renewal application. ACN: 9811020157 Fiche: A5671:289-A5671:299
October 28, 1998	NRC letter (from S. Hoffman) forwarding notification of November 10, 1998 meeting in Charlotte, North Carolina to review material associated with electrical scoping process used for the Oconee license renewal application. ACN: 9810300285 Fiche: A5644:201-A5644:203
October 28, 1998	NRC letter (from J. Sebrosky) forwarding notification of November 6, 1998 meeting to review material associated with fire protection scoping process used for license renewal application for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810300236 Fiche: A5644:289-A5644:291
October 28, 1998	Meeting notice of November 10, 1998 meeting in Charlotte, North Carolina to discuss review material associated with electrical scoping process used for the Oconee license renewal application. Meeting was canceled. ACN: 9811160042 Fiche: A5836:358-A5836:360

October 23, 1998	NRC letter (from the Chairman) expressing appreciation for supporting Commission initiative in issuing a recent statement of policy on conduct of adjudicatory proceedings. ACN: 9811030176 Fiche: A5672:352-A5672:353
October 23, 1998	NRC letter (from J. Sebrosky) forwarding notification of October 30, 1998 meeting to review material associated with scoping process used for license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810290116 Fiche: A5622:358-A5622:360
October 22, 1998	NRC letter (from J. Sebrosky) forwarding summary of September 28, 1998 meeting regarding status of license renewal activities for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810290082 Fiche: A5622:317-A5622:333
October 15, 1998	NRC letter (from S. Hoffman) forwarding notification of October 29, 1998 meeting in Rockville, Maryland to discuss status of review of license renewal application of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810200270 Fiche: A5468:234-A5468:236
October 15, 1998	Meeting notice of October 22, 1998 meeting in Rockville, Maryland for Duke Energy Corporation to brief NRC reviewers on electrical scoping done to support license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810190106 Fiche: A5458:049-A5458:051
October 14, 1998	NRC letter informing that NRC staff has set up a single electronic mail address to receive all communications in listed proceeding concerning the license renewal application for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810190044 Fiche: A5430:350-A5430:350
October 9, 1998	NRC staff response (signed by M. Zobler) to petition for leave to intervene filed by N. Williams, W. Clay, W. Lesan, and the Chattooga River Watershed Coalition. ACN: 9810140068 Fiche: A5395:066-A5395:082
October 1, 1998	Meeting notice of October 15, 1998 meeting in Rockville, Maryland to discuss NRC management of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810050252 Fiche: A5301:174-A5301:176
October 1, 1998	Order (signed by B. Cotter) ruling on motion for 30-day extension to file amended petition to intervene. ACN: 9810050047 Fiche: A5296:117-A5296:122

September 30, 1998	Amendment (signed by B. Williams) to the Chattooga River Watershed Coalition petition to intervene in proceedings regarding application of Duke Energy Corporation to renew the operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810060063 Fiche: A5315:220-A5315:221
September 30, 1998	Letter (from N. Williams) requesting that submitted information be attached to amendments to petition to intervene in proceedings regarding application of Duke Energy Corporation to renew operating licenses for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810050036 Fiche: A5296:114-A5296:114
September 30, 1998	Response from Duke Energy Corporation (signed by D. Repka) to request of N. Williams, W. Clay, W. Lesan, and the Chattooga River Watershed Coalition for enlargement of time. ACN: 9810020158 Fiche: A5281:050-A5281:055
September 29, 1998	NRC staff response (signed by M. Zobler) to motion for enlargement of time filed by N. Williams, W. Clay, W. Lesan, and the Chattooga River Watershed Coalition. ACN: 9810020038 Fiche: A5281:193-A5281:197
September 28, 1998	Letter (from E. Julian) acknowledging receipt of message requesting enlargement of time for purpose of retaining counsel. ACN: 9810020054 Fiche: A5281:206-A5281:209
September 27, 1998	Letter (from B. Williams) requesting consideration of motion to enlarge time required to submit amended petition to intervene in proceeding regarding application of Duke Energy Corporation to renew operating licenses for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9810020138 Fiche: A5281:192-A5281:192
September 25, 1998	Meeting notice of October 1, 1998 meeting in Rockville, Maryland to discuss scoping and screening methodology used in preparation of the Oconee license renewal application. ACN: 9809300301 Fiche: A5266:324-A5266:326
September 25, 1998	Notice of appearance (signed by M. Zobler) informing that M. Zobler, R. Weisman, and J. Moore will enter appearances in proceeding regarding license renewal of Oconee Nuclear Station Unit Nos. 1, 2, and 3. ACN: 9809290069 Fiche: A5246:274-A5246:278
September 24, 1998	Letter from Duke Energy Corporation (from D. Repka) forwarding notices of appearances for attorneys representing Duke Energy Corporation, the applicant, in the proceeding for license renewal of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9809280110 Fiche: A5229:305-A5229:312

September 24, 1998	Letter (from E. Julian) informing that Office of the Secretary experienced problems with dedicated e-mail. In an effort to maintain an electronic mailbox for parties filing by e-mail, an alternate mailbox has been created. ACN: 9809280092 Fiche: A5229:294-A5229:297
September 18, 1998	Memorandum and order (signed by B. Cotter) stating that applicant and staff shall file respective answers after petitioners file any amendment to intervention petition. ACN: 9809220082 Fiche: A5152:305-A5152:314
September 18, 1998	Notice of reconstitution of board (signed by B. Cotter) providing notification of reconstitution by appointing B. Cotter as board chairman in place of T. Moore in Duke Energy Corporation license renewal proceeding. ACN: 9809220025 Fiche: A5152:266-A5152:269
September 16, 1998	Establishment of an Atomic Safety and Licensing Board (signed by B. Cotter) for proceeding regarding application by Duke Energy Corporation to renew operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9809180047 Fiche: A5125:343-A5125:346
September 15, 1998	Order (signed by J. Hoyle) referring a petition for intervention and request for hearing to ASLBP. Commission directs licensing board to conduct proceeding in accordance with guidance specified in order. ACN: 9809170031 Fiche: A5109:305-A5109:316
September 15, 1998	Memorandum (signed by J. Hoyle) forwarding petition to intervene of N. Williams, W. Clay, W. Lesan, and the Chattooga River Watershed Coalition with respect to application of Duke Energy Corporation to renew the operating licenses for the Oconee Nuclear Station Unit Nos. 1, 2, and 3. ACN: 9809170007 Fiche: A5109:280-A5109:287
September 14, 1998	Meeting summary of August 20, 1998 meeting with Duke Energy Corporation regarding status of utility license renewal activities for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9809160300 Fiche: A5087:338-A5087:353
September 11, 1998	Meeting notice of September 28, 1998 meeting in Rockville, Maryland to discuss status of review of the license renewal application for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9809170068 Fiche: A5119:260-A5119:262

September 8, 1998	Letter (from B. Williams) informing that author along with listed individuals and Chattooga River Watershed Coalition hereby file petition for leave to intervene with full intent to amend said petition as appropriate and in a timely manner. ACN: 9809170016 Fiche: A5109:281-A5109:287
August 31, 1998	Letter from Duke Energy Corporation submitting "License Renewal Flow Diagrams for Oconee Nuclear Station, Unit Nos. 1, 2, and 3," Volumes II and III. ACN: 9809100206 Fiche: A5060:154-A5060:169
August 12, 1998	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding licensee's comments on April 27 – 29, 1998 site visit by NRC regarding containment review for license renewal of the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9808180306 Fiche: A4734:243-A4734:263
August 10, 1998	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding 26 additional copies of Volumes I, II, and III of application for renewal of operating licenses for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9808180281 Fiche: A4698:148-A4698:151
August 5, 1998	Notice of acceptance (from C. Grimes) for docketing of application and notice of opportunity for hearing regarding renewal of licenses DPR-38, DPR-47, and DPR-55. ACN: 9808110042 Fiche: A4582:191-A4582:195
August 5, 1998	Letter (from J. Roe) forwarding notice of acceptance for docketing of application and notice of opportunity for hearing regarding renewal of licenses DPR-38, DPR-47, and DPR-55. ACN: 9808110037 Fiche: A4582:186-A4582:195
July 31, 1998	NRC letter (from C. Grimes) forwarding proposed safety and environmental review schedule for licensee's license renewal application for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9808070326 Fiche: A4545:201-A4545:203
July 28, 1998	Meeting notice of August 20, 1998 meeting with Duke Energy Corporation in Rockville, Maryland to discuss the status of review of the license renewal application for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9808070293 Fiche: A4545:282-A4545:283
July 6, 1998	Letter from Duke Energy Corporation forwarding application for renewal of operating licenses for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. Requests extension of operating licenses to 20 years beyond current expiration dates. ACN: 9807200136 Fiche: A4344:001-A4347:255

July 1, 1998	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding "License Renewal Flow Diagrams for Oconee Nuclear Station, Unit Nos. 1, 2, and 3," Volume I. ACN: 9807070270 Fiche: A4171:261-A4171:268
June 29, 1998	Letter from Duke Energy Corporation (signed by W. McCollum) discussing September 11, 1997 letter from the NRC to Duke Energy Corporation, which indicated that submittal of seven sets of scoping drawings referenced in the Oconee license renewal application was acceptable. ACN: 9807020300 Fiche: A4035:289-A4035:290
June 5, 1998	Trip report (signed by C. Regan) of April 27 – 29, 1998 visit to the Oconee Nuclear Station, Units 1, 2, and 3 to discuss issues regarding review of license renewal application ACN: 9806100174 Fiche: A3728:181-A3728:200
June 3, 1998	Meeting summary of March 30, 1998 meeting regarding the status of license renewal activities for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9806080248 Fiche: A3721:163-A3721:177
May 28, 1998	NRC letter forwarding revised NRC Form 398, "Personal Qualification Statement – Licensee." Effective immediately, all applications for new licenses or license renewals must be submitted on revised form. ACN: 9806160342 Fiche: A3832:066-A3832:066
May 26, 1998	Meeting summary of April 29, 1998 meeting regarding the licensee's responses to November 14, 1997 NRC staff RAI on the plant reactor building to support the Oconee license renewal application. ACN: 9806040087 Fiche: A3681:318-A3681:329
April 15, 1998	NRC letter (from C. Grimes) informing that staff is scheduled to visit plant site on April 27 – 30, 1998 to support the NRC review of the Oconee license renewal application. ACN: 9806100183 Fiche: A3728:196-A3728:200
March 2, 1998	Letter from Duke Energy Corporation (signed by W. McCollum) forwarding evaluation of loss of prestress in post-tensioning system for 60 years of plant operation. ACN: 9803110107 Fiche: A2591:127-A2591:131
January 30, 1998	NRC letter (from S. Hoffman) discussing renewal activities and Duke Energy Corporation's plan to submit completed "Oconee License Renewal Technical Information Topical Report," for review in early 1998. ACN: 9802240020 Fiche: A2283:001-A2283:007

January 14, 1998	Letter from Duke Energy Corporation forwarding responses to RAIs regarding Oconee Nuclear Station, Unit Nos. 1, 2, and 3 license renewal technical information topical report OLRP-1001. ACN: 9801260125 Fiche: A1913:280-A1913:312
December 12, 1997	Duke Energy Corporation letter (signed by W. McCollum) informing that responses to NRC RAIs regarding review of "Oconee Nuclear Station, Unit Nos. 1, 2, and 3; License Renewal – Technical information TR, " OLRP-1001, Revision 1, dated February 1997, are being prepared and will be submitted by letter dated January 30, 1998. ACN: 9712090083 Fiche: A1385:348-A1385:350
November 14, 1997	Letter (from S. Hoffman) forwarding an RAI concerning Sections 2.3 and 3.3 of the Oconee Nuclear Station Unit Nos. 1, 2, and 3 license renewal application. ACN: 9711200381 Fiche: A1194:043-A1194:051
November 5, 1997	Duke Energy Corporation letter (signed by W. McCollum) providing status of license renewal activities in support of preparation of the Oconee license renewal application. Five key topics that will require NRC attention in the coming months are identified and discussed. ACN: 9711170097 Fiche: A1177:349-A1177:355
October 1, 1997	NRC letter (from S. Hoffman) informing Duke Energy Corporation that the staff intends to use working draft SRP-LR as an aid in reviewing license renewal submittal received from Duke Energy Corporation, other licensees, and Owners Groups. Policy issues will be referred to the Commission for resolution. ACN: 9710060083 Fiche: A0643:141-A0643:146
September 16, 1997	Summary of August 28, 1997 meeting with Babcock and Wilcox Owners Group regarding management of aging effects for reactor vessel internals and cavities related to baffle bolting integrity issues. ACN: 9709240080 Fiche: A0517:339-A0517:361
September 12, 1997	Meeting summary (from S. Hoffman) of August 14, 1997 meeting to discuss status of license renewal activities for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9709240278 Fiche: A0522:210-A0522:217
September 11, 1997	NRC letter (from S. Hoffman) forwarding comments on acceptability of approach for developing drawings to be submitted to support the Oconee license renewal application. ACN: 9709180151 Fiche: A0421:026-A0421:030

September 3, 1997	NRC letter (from S. Hoffman) responding to Duke Energy Corporation letter requesting feedback on format, content, and level of detail provided regarding mechanical component example. Results of review contained in enclosure. ACN: 9709090265 Fiche: A0309:227-A0309:234
August 8, 1997	Notification of August 14, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss status of Duke Energy Corporation's license renewal activities and NRC staff reviews. ACN: 9708130071 Fiche: A0028:355-A0028:359
August 5, 1997	Summary of July 17, 1997 meeting with Duke Energy Corporation regarding license renewal activities for Oconee Nuclear Station Unit Nos. 1, 2, and 3. ACN: 9708080118 Fiche: A0009:286-A0009:291
August 4, 1997	NRC letter (from S. Hoffman) providing comments on the Oconee Nuclear Station electrical and structural examples submitted by Duke Energy Corporation on June 10, 1997. ACN: 9708070248 Fiche: 94735:340-94735:351
August 4, 1997	Duke Energy Corporation letter (signed by W. McCollum) forwarding three examples of Oconee License Renewal Technical Information TR, OLRP-11 in response to utility agreement to provide vertical slice of mechanical review. Staff review and feedback requested. ACN: 9708110275 Fiche: A0026:253-A0026:293
July 30, 1997	Summary of July 17, 1997 meeting with Duke Energy Corporation to provide information on integrated plant assessment and time-limited aging analysis reviews for mechanical components that will be submitted as part of the licensee's license renewal report for Oconee Nuclear Station, Units 1, 2, and 3. ACN: 9708040107 Fiche: 93996:265-93996:300
June 26, 1997	Summary of June 3, 1997 meeting with Duke Energy Corporation to discuss status of license renewal activities for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9707010321 Fiche: 93585:175-93585:288
June 25, 1997	Notification of July 17, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss Duke's presentation on mechanical components vertical slice submittal and staff feedback on Duke's structural and electrical component vertical slice submittals. ACN: 9706270217 Fiche: 93554:320-93554:323

June 24, 1997	Notification of July 16, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss Duke's planned submittals for mechanical components. ACN: 9706260228 Fiche: 93552:295-93552:298
June 10, 1997	Duke Energy Corporation letter (signed by J. Hampton) expressing appreciation for June 3, 1997 meeting with NRC to discuss license renewal, integrated plant assessment and time-limited aging analysis review. ACN: 9706180174 Fiche: 93432:330-93432:332
May 21, 1997	Notification of June 3, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss Duke's planned submittals for structures and electrical components. ACN: 9705230309 Fiche: 93085:011-93085:014
May 19, 1997	Summary of May 15, 1997 meeting with Duke Energy Corporation regarding draft sections of plant license renewal technical information report, OLRP-1001. ACN: 9705210258 Fiche: 93042:255-93042:258
May 19, 1997	Duke Energy Corporation Letter (signed by J. Hampton) expressing appreciation for May 5, 1997 meeting with NRC to discuss various license renewal topics. Includes list of owners group topical reports and example description of new inspection program to be included in the enclosed license renewal application. ACN: 9705300066 Fiche: 93165:305-93165:312
May 16, 1997	Summary of May 15, 1997 meeting with Duke Energy Corporation regarding draft sections of Oconee Nuclear Station license renewal technical information report, OLRP-1001. ACN: 9705200350 Fiche: 93042:255-93042:258
May 13, 1997	Notification of May 14, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss status of license renewal activities for Oconee Nuclear Station. ACN: 9705150347 Fiche: 92964:273-92964:276
April 30, 1997	Notification of May 8, 1997 meeting with Duke Energy Corporation in Rockville, Maryland to discuss status of Duke license renewal activities for Oconee Nuclear Station, Unit Nos. 1, 2, and 3. ACN: 9705020217 Fiche: 92738:001-92738:004
March 12, 1997	Duke Energy Corporation letter forwarding Revision 1 of report "Oconee Nuclear Station, License Renewal – Technical Information TR," OLRP-1001. ACN: 9703240242 Fiche: 93091:065-93091:143

February 28, 1997	Revision 1 of Duke Energy Corporation report, "Oconee Nuclear Station, License Renewal – Technical Information TR," OLRP-1001. ACN: 9703240243 Fiche: 93091:071-93091:143
January 22, 1997	Summary of January 6, 1997 site visit and meeting with Duke Energy Corporation in Charlotte, North Carolina to discuss staff comments on revised Oconee license renewal technical information report OLRP-1001, dated November 4, 1996. ACN: 9701280144 Fiche: 91538:006-91538:021
January 8, 1997	Summary of December 5, 1996 meeting with Duke Energy Corporation regarding license renewal technical information submittals associated with TR OLRP-1001. ACN: 9701150266 Fiche: 91444:152-91444:156
December 19, 1996	Notification of January 7, 1997 meeting with Duke Energy Corporation in Charlotte, North Carolina to discuss staff comments resulting from review of generic license renewal format and content specification document. ACN: 9612230235 Fiche: 91194:310-91194:313
November 26, 1996	Notification of December 5, 1996 meeting with Duke Energy Corporation in Rockville, Maryland to discuss schedule for staff's review of Duke's generic format and content document for future license renewal submittals. ACN: 9612030008 Fiche: 90980:328-90980:330
October 21, 1996	Notification of November 5, 1996 meeting with Duke Energy Corporation in Rockville, Maryland to discuss submittal schedule of Oconee license renewal technical reports. ACN: 9610230019 Fiche: 90523:317-90523:317
September 27, 1996	Summary of September 18, 1996 meeting with Duke Energy Corporation regarding deficiencies in its license renewal technical information report for the Oconee Nuclear Station, Unit Nos. 1, 2, and 3 that prevent the NRC from starting a review. ACN: 9610010278 Fiche: 89885:351-89885:356
September 6, 1996	NRC letter (signed by S. Newberry) informing Duke Energy Corporation that the July 31, 1996 submittal does not contain adequate information for review. Suggests it would be beneficial to initiate discussion between utility and staff on necessary format and content before utility revises first submittal or before utility submits additional reports for review. ACN: 9609120241 Fiche: 89638:177-89638:179
August 31, 1996	Duke Energy Corporation report "Oconee Nuclear Station, License Renewal - Technical information TR, OLRP-1001." ACN: 9608050192 Fiche: 89266:149-89266:189

August 29, 1996	Meeting notice of September 18, 1996 meeting with Duke Energy Corporation in Rockville, Maryland to discuss license renewal technical report submittals. ACN: 9609100452 Fiche: 89615:300-89615:301
August 22, 1996	Summary of August 14, 1996 meeting with Duke Energy Corporation regarding plant license renewal technical information report (OLRP-1001) for Oconee Unit Nos. 1, 2, and 3. ACN: 9608260013 Fiche: 89455:302-89455:308
August 2, 1996	NRC letter (signed by S. Newberry) acknowledging receipt of February 2, 1996 letter requesting that the NRC waive Part 170 fees for staff review of plant-specific license renewal technical information necessary for eventual license renewal application for plant. ACN: 9608080006 Fiche: 89290:166-89290:167
July 31, 1996	Letter (from J. Hampton) forwarding "Oconee Nuclear Station, License Renewal - Technical Information Title: TR,OLRP-1001. ACN: 9608050190 Fiche: 89266:146-89266:189
May 21, 1996	NRC letter (signed by S. Newberry) discussing the April 26, 1996 visit to Oconee Nuclear Station to review implementation of NEI Guideline 95-10, Revision 0, "Industry Guideline for Implementing 10 CFR Part 54 – License Renewal Rule." ACN: 9605240191 Fiche: 88344:001-88344:039

APPENDIX B
REFERENCES

This appendix contains a listing of references used in the preparation of the Safety Evaluation Report prepared during the review of the license renewal application for Oconee Nuclear Power Plant Units 1, 2, and 3 under Docket Numbers 50-269, 50-270, and 50-287.

American Society of Mechanical Engineers (ASME)

---, Boiler and Pressure Vessel Code, Section III, Rules for Construction of Nuclear Power Plant Components through Summer 1979

---, Section XI, Rules for Inservice Inspection of Nuclear Power Plant Components

---, Section XI, Examination Categories B-P, C-H, D-A, D-B, D-C

---, USAS B31.7, USA Standard Code for Pressure Piping, Nuclear Power Piping, 1968

Babcock and Wilcox

BAW-2225, "Response to Request for Additional Information (RAI) Regarding Reactor Vessel Pressure Vessel Integrity," B&WOG, May 1998

BAW-2225, Revision 1,"Response to Request for Additional Information (RAI) Regarding Reactor Vessel Pressure Vessel Integrity," B&WOG, January 1999.

BAW-2241P, "Fluence and Uncertainty Methodologies," May 1997.

BAW-2243A, "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," March 1995.

BAW-2244A, "Demonstration of the Management of Aging Effects for the Pressurizer," August 1997.

BAW-2248, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," July 1997.

BAW-2251, "Demonstration of the Management of Aging Effects for the Reactor Vessel," June 1996.

BAW-2274, "Fracture Mechanics Analysis of Postulated Underclad Cracks in B&W Designed Reactor Vessels for the Period of Extended Operation, B&WOG, December 1996.

BAW-2275, "Low Upper-Shelf Toughness Fracture Mechanics Analysis of B&W Designed Reactor Vessels for 48 EFPY," Babcock & Wilcox Owners Group, August, 1996.

BAW-2301, "B&WOG Integrated Response to Generic Letter 97-01, `Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations'," July 1997.

BAW-10008, "Reactor Internals Stress and Deflection Due to Loss-of-Coolant Accident and Maximum Hypothetical Earthquake," Part 1, Rev. 1, Babcock & Wilcox, Lynchburg, VA, June 1970.

Letter from William R. Gray to David B. Matthews, B&WOG Generic License Renewal Program Topical Report BAW-2248, "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals" (RAIs 1through 14 from December 4, 1998), dated February 18, 1999.

Duke Energy Corporation (Duke)

Correspondence

Letters from H.B. Tucker (Duke) to Document Control Desk (NRC), dated May 23, 1988 and August 1, 1998, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants (Generic Letter 88-05)."

ONS Letter from W. R. McCollum, Jr to US NRC dated January 7, 1998.

Letter from M. S. Tuckman (Duke) to Document Control Desk (NRC) dated November 11, 1998, "Response to Generic Letter 98-04."

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---, NSAC-202L, Revision 1, "Recommendations for an Effective Flow-Accelerated Corrosion Program," November 1996.

---, Technical Report 102135-R4, "PWR Secondary Water Chemistry Guidelines, Revision 4," November 1996.

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---, Technical Report 105759, “An Environmental Factor Approach to Account for Reactor Water Effects in Light Water Reactor Pressure Vessel and Piping Evaluations,” December 1995

---, Technical Report 106092, "Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems," September 1997.

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Nuclear Energy Institute

Letter from D.J. Modeen (NEI) to G.C. Lainas (USNRC), "Responses to NRC Requests for Additional Information on Generic Letter 97-01,"dated December 28, 1998.

NEI 95-10 (Revision 0), “Industry Guideline for Implementing the Requirements of 10 CFR Part 54—The License Renewal Rule,” March 1996.

Sandia National Laboratory

SAND 96-0344, Aging Management Guideline for Commercial Nuclear Power Plants-Electrical Cable and Terminations, September 1996, Sandia National Laboratories for The U. S. Department of Energy.

U.S. Nuclear Regulatory Commission (NRC)

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BL-88–08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," June 22, 1988

BL-88-11, “Pressurizer Surge Line Stratification, ” December 20, 1988

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GL 81-07, NUREG-0612, “Control of Heavy Loads,” February 1981

GL 85-20, "Resolution of Generic Issue 69: High Pressure Injection/Makeup Nozzle Cracking in Babcock and Wilcox Plants," dated November 11, 1985.

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IN 97-46, "Unisolable Crack in High-Pressure Injection Piping," dated July 9, 1997.

IN 82-09, "Cracking in Piping of Makeup Coolant Linea at B&W Plants," dated March 31, 1982.

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Letter from L.A. Wiens (USNRC) to J.W. Hampton (Oconee Nuclear Station), "Safety Evaluation of Control Rod Drive Mechanism (CRDM) Penetration Inspection Results-Oconee Unit 2 (TAC No. M90773)," dated March 31, 1995.

Letter from D.E. Labarge (USNRC) to J.W. Hampton (Oconee Nuclear Station), "Structural Integrity of Control Rod Drive Mechanism (CRDM) Penetration Nozzles No. 23 and 63–Oconee Nuclear Station Unit 2 (TAC No. M95291)," dated December 11, 1996.

Letter from Raj K. Anand to David J. Firth, "Request for Additional Information (RAI) Regarding the Babcox & Wilcox Owners Group Generic License Renewal Program Entitled, Demonstration of the Management of Aging Effects for the Reactor Vessel Internals, BAW–2248, July 1997", dated December 2, 1998.

Letter from J.R. Strosnider (USNRC) to D.J. Modeen (NEI), "Review of Generic Response to the NRC Requests for Additional Information Regarding Generic Letter 97-01," dated March 21, 1999.

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BAW-2243, Letter, March 21, 1996, "Acceptance for Referencing of Topical Report BAW-2243, 'Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping,'" from Dennis M. Crutchfield, NRC, to Don Croneberger, B&W Nuclear Service Company.

BAW-2244, Letter, August 18, 1997, "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled, 'Demonstration of the Management of Aging Effects for the Pressurizer,' BAW-2244, August 1995," from Marylee M. Slosson, NRC, to David J. Firth, Framatome Technologies, Inc.

BAW-2248, Letter, December 9, 1999, "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled,'Demonstration of the Management of Aging Effects for the Reactor Vessel Internals,' BAW-2248, July 1997," from Christopher I. Grimes, NRC, to William R. Gray, Framatome Technologies, Inc.

BAW-2251, Letter, April 26, 1999, "Acceptance for Referencing of Generic License Renewal Program Topical Report Entitled, 'Demonstration of the Management of Aging Effects for the Reactor Vessel,' BAW-2251, June 1996," from Christopher I. Grimes, NRC, to David J. Firth, the B&W Owners Group.

APPENDIX C
ABBREVIATIONS

ABVS	auxiliary building ventilation system
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ACSR	aluminum conductors that are steel reinforced
AHU	air handling unit
AISC	American Iron and Steel Institute
AMG	aging management guideline
AMP	aging management program
AMR	aging management review
ANO	Arkansas Nuclear One
ANL	Argonne National Laboratory
ANSI	American National Standards Institute
APCSB	auxiliary power conversion system branch
ASME	American Society of Mechanical Engineers
ASTM	American Society for Testing and Materials
ASW	auxiliary service water
ASWS	auxiliary service water system
ATWS	anticipated transient without scram
B&W	Babcock and Wilcox
B&WOG	Babcock and Wilcox Owners Group
BTP	branch technical position
BWST	borated water storage tank
CAS	central alarm station
CCP	chemistry control program
CCW	condenser circulating water
CHCS	containment hydrogen control system
CLB	current licensing basis
CF	core flood
CFR	U. S. Code of Federal Regulations
CFT	core flood tank
CRDM	control rod drive mechanism
CRDMMTH	control rod drive mechanism motor tube housing
CRPFS	control room pressurization and filtration system
CS	condensate system
CUF	cumulative usage factor
DUKE	Duke Energy Corporation
DBE	design-basis events
DG	draft regulatory guide
DOR	Division of Operating Reactors

ECCS	emergency core cooling system
EDG	emergency diesel generator
EFS	emergency feedwater system
EFPY	effective full power years
EFWP	emergency feedwater pump
EOL	end of life
EPDM	ethylene propylene diene monomer
EPRI	Electric Power Research Institute
EQ	environmental qualification
FERC	Federal Energy Regulatory Commission
EFPY	effective full-power year
FIV	flow-induced vibration
FMP	fatigue management program
FP	fire protection
FRERP	Federal Radiological Monitoring and Assessment Plan
FSAR	final safety analysis report
FS	feedwater system
GDC	general design criteria
GEIS	generic environmental impact statement
GL	generic letter
GSI	generic safety issue
HAZ	heat-affected zone
HEPA	high-efficiency particulate air (filter)
HMWPE	high-molecular-weight polyethylene
HPI	high-pressure injection
HPIS	high-pressure injection system
HPSW	high-pressure service water
HUPCAPS	high-fluence supplementary weld metal surveillance capsules
HVAC	heating, ventilation, and air conditioning
IASCC	irradiation-assisted stress-corrosion cracking
IEB	Inspection and Enforcement Bulletin
IGA	intergranular attack
IPA	integrated plant assessment
ILRT	integrated leak rate test
ISFSI	independent spent fuel storage installation
ISI	inservice inspection
IST	inservice testing
ISTS	improved standard technical specification
ITG	issues task group
ITS	improved technical specification
LBLOCA	large-break loss-of-coolant accident
LLRT	local leak-rate test
LOCA	loss-of-coolant accident
LOOP	loss of offsite power
LPI	low-pressure injection

LPSW	low-pressure service water
LRA	license renewal application
LRT	leak rate testing
LST	letdown storage tank
LWR	light-water reactor
MIC	microbiologically influenced corrosion
MRV	minimum required value
MIRVP	master integrated reactor vessel surveillance program
MSS	main steam system
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NEPA	National Environmental Policy Act
NPAR	nuclear plant aging research
NPS	nominal pipe size
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSAC	Nuclear Safety Analysis Center
NSR	neutron source reactor
NUREG	NRC technical report designation
ODSCC	outside-diameter stress-corrosion cracking
OLRFD	Oconee license renewal flow diagram
OSRDC	Oconee Safety-Related Designation Clarification
OLRP-1001	"Oconee Nuclear Station, License Renewal — Technical Information"
OLRP-1002	"Oconee Nuclear Station, License Renewal Flow Diagrams"
ONS	Oconee Nuclear Station's
ORVIP	Oconee reactor vessel integrity program
OSC	operational support center
OTSG	once-through steam generator
PAMS	post-accident monitoring system
PC	polar cranes
PIP	problem identification program
PIP	problem investigation process
PLL	prescribed lower limits
PRVS	penetration room ventilation system
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized-water reactors
PWSCC	primary water stress-corrosion cracking
QA	quality assurance
RAI	request for additional information
RBCS	reactor building cooling system
RBSS	reactor building spray system
RCP	reactor coolant pump

RCS	reactor coolant system
RCW	recirculated cooling water
RG	regulatory guide
RPV	reactor pressure vessel
RTD	resistance temperature detector
RVI	reactor vessel internals
RVIAMP	reactor vessel internals AMP
SBLOCA	small-break loss-of-coolant accident
SBO	station blackout
SC	structures and component
SCC	stress corrosion cracking
SCS	structures and component support
SE	safety evaluation
SER	safety evaluation report
SFCS	spent fuel cooling system
SFF	standby shutdown facility
SFP	spent fuel pool
SFPC	spent fuel pool cooling
SG	steam generator
SGT	steam generator tube
SLC	selected licensee commitments
SOC	statement of considerations
SPCS	steam and power conversion systems
SR	surveillance requirement
SRP	standard review plan
SSC	stress corrosion cracking
SSC	structures, systems, and components
SSF	standby shutdown facility
SSW	secondary shield wall
SUPCAPS	supplementary weld metal surveillance capsules
TLAA	time-limited aging analyses
TMI	Three Mile Island
TMI-2	Three Mile Island Unit 2
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
USAEC	U.S. Atomic Energy Commission
USAS	United States of America Standards
USE	upper-shelf energy
VDC	volts direct current
VDIL	vents, drains, and instrument lines
VHP	vessel head penetration
WC	chilled water system
XLPE	cross-linked polyethylene

APPENDIX D

PRINCIPAL CONTRIBUTORS

NAME	RESPONSIBILITY
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M. Banic	Materials Engineering
H. Brammer	Mechanical Engineering
F. Burrows	Electrical Engineering
W. Burton	Technical Support
T. Cheng	Structural Engineering
S. Chey	Clerical Support
R. Croteau	Technical Support
S. Coffin	Materials Engineering
J. Davis	Materials Engineering
T. Eaton	Plant Systems (Fire Protection)
B. Elliot	Materials Engineering
J. Fair	Mechanical Engineering
G. Georgiev	Structural Engineering
C. Gratton	Plant Systems
S. Green	Clerical Support
F. Grubelich	Mechanical Engineering
J. Guo	Plant Systems
J. Harold	Technical Support
A. Hiser	Materials Engineering
S. Hou	Structural Engineering
J. Huang	Inservice Testing and Inspection
C. Jackson	Reactor Systems
D. Jeng	Structural Engineering
P. Kang	Technical Support
S. Koenick	Technical Support
L. Kopp	Reactor Systems
P. Kuo	Technical Support
R. Latta	Quality Assurance
C. Li	Plant Systems
Y. Li	Mechanical Engineering
T. Liu	Technical Support
W. Liu	Technical Support
S. Lee	Technical Support
J. Ma	Structural Engineering
J. Medoff	Materials Engineering
J. Moore	Legal Counsel

C. Munson	Structural Engineering
D. Nguyen	Electrical Engineering
P. Patnaik	Structural Engineering
K. Parczewski	Chemical Engineering
J. Peralta	Quality Assurance
R. Prato	Technical Support
J. Rajan	Mechanical Engineering
J. Raval	Plant Systems
M. Razzaque	Reactor Systems
P. Shemanski	Electrical Engineering
M. Snodderly	Plant Systems
E. Sullivan	Materials Engineering
D. Thatcher	Electrical Engineering
B. Thomas	Plant Systems
H. Wang	Technical Support
R. Weisman	Legal Counsel
S. West	Fire Protection
M. Zobler	Legal Counsel

CONTRACTORS

Contractor	Technical Area
Brookhaven National Laboratory	Aging Management Review

APPENDIX E
CHRONOLOGY OF NRC'S
REQUESTS FOR ADDITIONAL INFORMATION

During the review of the Oconee Nuclear Station (ONS) license renewal application (LRA), the staff requested additional information of Duke Energy Corporation (Duke). Some of these requests for additional information (RAIs) are discussed throughout this report. The RAIs were assigned a number based on the section of the LRA that the staff was reviewing. For example, RAI 2.5.3-3 was the third issue identified during the staff's review of Section 2.5.3 of the LRA. The following table is a list of the issuance and response dates of the RAIs that have been asked regarding the LRA.

The table includes RAIs that were issued in a November 14, 1997, letter, which predates the July 6, 1998, LRA. Before submitting its application, Duke had submitted a report to the staff and asked that the staff evaluate the portion dealing with the ONS reactor buildings. As of June 1998, Duke had responded to the NRC staff RAIs, hosted a site visit by NRC staff officials in April 1998, and revised containment-related portions of its application to incorporate additional information.

In addition, the table also includes potential open items that were sent to Duke in April 8, 1999, and April 16, 1999, letters. In an effort to minimize the number of open items in the safety evaluation report (SER), the staff decided that the potential open item list would be made available to Duke before the SER was issued. Some of these potential open items involved information that was submitted in response to a staff RAI. In these cases, the potential SER open item used the original RAI number for reference. The table below identifies these potential open items as followon questions in the comments column of the table. When a potential open item was identified that was not associated with a previous RAI, it was given a new number. Duke noted in its May 10, 1999, response to the potential open items that it decided to defer addressing 13 of the items. In the cases were Duke did not provide an answer or only provided a partial answer the comments column provides a reference to the open item in the June 1996 version of this report that discussed the issue. This report has been revised to include a description, in each applicable section, of the manner by which these items have been resolved.

Subsequent to the issuance of the June 1999 version of this report the staff evaluated additional information submitted by Duke. The evaluation is contained in various sections of this report. A staff evaluation was performed on the following Duke submittals:

- Duke's September 30, 1999, submittal that amended the LRA based on changes to the Oconee current licensing basis that materially affected the contents of the application.

- Duke's October 15, 1999, submittal that provided the response to the open items and confirmatory items contained in the June 16, 1999, version of this report. The October 15, 1999, submittal also contained several comments on the June SER. These comments were reviewed by the staff and in some cases the SER was revised to resolve Duke's comments.

- Duke's June 22, 1999, and November 30, 1999, submittal regarding the resolution of SER open item 2.1.3.1-1 concerning the scoping methodology used by Duke to comply with the requirements of 10 CFR 54.4. The response to SER open item 2.1.3.1-1 was also amended by Duke's submittal dated December 17, 1999.

- Duke's submittal dated December 17, 1999, which provided responses to a staff letter dated November 18, 1999. The purpose of the November 18, 1999, letter was to provide Duke with the status regarding any items that were not resolved at the time regarding the ONS LRA.

- Duke's submittal dated January 7, 2000, that provided a response to a staff letter dated December 14, 1999. The issue in these letters involves the design of the ONS borated water systems.

- Duke's submittal dated January 12, 2000, that provided a response to a staff letter dated January 4, 2000. The issue in these letters involve aging effects of insulated cables at ONS.

Question Number	Issued	Response	Comments
G-1	11/18/98	2/17/99	general question
G-1	4/8/99	5/10/99	followon to a general question
G-2	11/18/98	2/17/99	general question
G-3	11/18/98	2/17/99	general question
G-4	12/3/98	2/17/99	general question
G-5	12/3/98	2/17/99	general question
G-6	12/3/98	2/17/99	general question
G-7	12/3/98	2/17/99	general question
G-8	12/3/98	2/17/99	general question
G-9	12/3/98	2/17/99	general question
1.5.2-1	11/20/98	2/17/99	
1.5.5-1	11/24/98	2/17/99	
1.5.5-1	4/8/99	5/10/99	followon question
2-1	12/1/98	2/17/99	
2-2	4/8/99	5/10/99	Duke did not provide a response to this item. See item 2.1.3.1-1 of the SER
2.2-1	11/30/98	2/17/99	

Question Number	Issued	Response	Comments
2.2-2	11/30/98	2/17/99	
2.2-3	11/30/98	2/17/99	
2.2-4	11/30/98	2/17/99	
2.2-5	11/30/98	2/17/99	
2.2-6	12/1/98	2/17/99	Revised Duke response 3/18/99
2.2-7	12/2/98	1/25/99	
2.2-7	4/8/99	5/10/99	followon question
2.2-8	12/2/98	2/17/99	
2.2-9	12/2/98	2/8/99	
2.3-1	11/14/97	7/6/98	
2.3-2	11/14/97	7/6/98	
2.3-3	11/14/97	7/6/98	
2.3-4	11/14/97	7/6/98	
2.3-5	11/14/97	7/6/98	
2.3-6	11/14/97	7/6/98	
2.3-7	11/14/97	7/6/98	
2.3-8	11/19/98	2/8/99	
2.3-8	4/16/99	5/10/99	followon question
2.3-9	11/19/98	2/8/99	
2.3-9	4/16/99	5/10/99	followon question
2.3-10	11/19/98	2/8/99	
2.3-11	12/1/98	2/8/99	
2.4-1	11/30/98	1/25/99	
2.4-2	11/30/98	2/17/99	
2.4-3	11/30/98	2/17/99	
2.4-4	11/30/98	2/17/99	
2.4-5	11/30/98	2/17/99	

Question Number	Issued	Response	Comments
2.4-6	11/30/98	2/17/99	
2.4-7	11/30/98	2/17/99	
2.5-1	4/16/99	5/10/99	
2.5.2-1	4/16/99	5/10/99	
2.5.3-1	12/1/98	2/17/99	
2.5.3-2	12/1/98	2/17/99	
2.5.3-3	12/1/98	2/17/99	
2.5.3-4	12/1/98	2/17/99	
2.5.3-5	12/1/98	1/25/99	
2.5.3-6	12/1/98	2/8/99	
2.5.4-1	12/1/98	2/8/99	
2.5.5-1	11/30/98	2/17/99	
2.5.5-2	11/30/98	2/17/99	Also see Duke letter dated January 7, 2000
2.5.5-3	11/30/98	2/8/99	
2.5.5-4	11/30/98	1/25/99	
2.5.5-5	11/30/98	1/25/99	
2.5.6-1	12/2/98	1/25/99	
2.5.6-2	12/2/98	1/25/99	
2.5.6-3	12/2/98	1/25/99	
2.5.6-4	12/2/98	1/25/99	
2.5.6-5	12/2/98	1/25/99	
2.5.6-6	12/2/98	1/25/99	
2.5.6-7	12/2/98	1/25/99	
2.5.6-8	12/2/98	1/25/99	
2.5.6-9	12/2/98	2/17/99	
2.5.6-10	12/2/98	1/25/99	
2.5.6-11	12/2/98	1/25/99	

Question Number	Issued	Response	Comments
2.5.6-12	12/2/98	1/25/99	
2.5.6-13	12/2/98	1/25/99	
2.5.6-14	12/2/98	2/8/99	
2.5.7-1	11/30/98	2/8/99	
2.5.7-2	11/30/98	1/25/99	
2.5.8-1	11/24/98	2/8/99	
2.5.8-1	4/8/99	5/10/99	followon question
2.5.8-1c	4/16/99	5/10/99	revised a portion of the question that was sent to Duke on 4/8/99
2.5.8-2	11/24/98	2/8/99	
2.5.8-3	11/24/98	1/25/99	
2.5.8-4	11/24/98	2/17/99	
2.5.9-1	11/21/98	1/25/99	
2.5.9-2	11/21/98	1/25/99	
2.5.9-3	11/21/98	1/25/99	
2.5.9-4	11/21/98	1/25/99	
2.5.9-5	11/21/98	1/25/99	
2.5.9-6	11/21/98	1/25/99	
2.5.9-7	11/21/98	1/25/99	
2.5.10-1	12/1/98	1/25/99	
2.5.10-2	12/1/98	1/25/99	
2.5.10-3	12/1/98	2/8/99	
2.5.13-1	11/20/98	1/25/99	
2.5.13-2	11/20/98	2/17/99	
2.5.13-3	11/20/98	2/17/99	
2.6-1	11/25/98	2/17/99	revised Duke response 3/18/99
2.6-2	11/25/98	2/17/99	
2.6-3	11/25/98	2/17/99	

Question Number	Issued	Response	Comments
2.6-4	11/25/98	2/17/99	
2.6-4	4/8/99	5/10/99	followon question
2.6-5	11/25/98	2/17/99	
2.6-6	11/25/98	2/17/99	
2.6-7	11/25/98	2/17/99	
2.6-6 & 2.6-7	4/8/99	5/10/99	followon question
2.6-8	11/25/98	2/17/99	
2.6-9	11/25/98	2/17/99	
2.6.1-1	12/1/98	2/17/99	
2.6.1-2	12/1/98	2/17/99	
2.6.1-3	12/1/98	2/17/99	revised Duke response 3/18/99
2.6.1-4	12/1/98	2/17/99	
2.6.7-1	12/1/98	2/17/99	revised Duke response 3/18/99
2.6.7-2	12/1/98	2/17/99	
2.7-1	11/18/98	2/17/99	
2.7-2	11/18/98	2/8/99	
2.7-3	11/18/98	2/8/99	
2.7-4	11/18/98	2/8/99	
2.7-5	11/18/98	2/8/99	
2.7-6	11/18/98	2/8/99	
2.7-7	11/18/98	2/8/99	
2.7-7	4/16/99	5/10/99	followon question
2.7-8	11/18/98	2/8/99	
2.7-8	4/16/99	5/10/99	followon question
2.7-9	11/18/98	2/8/99	
2.7-9	4/16/99	5/10/99	followon question

Question Number	Issued	Response	Comments
2.7-10	11/18/98	2/8/99	
2.7-11	4/8/99	5/10/99	
2.7-12	4/8/99	5/10/99	
2.7-12	4/16/99	5/10/99	revised the question that was sent to Duke on 4/8/99
2.7-13	4/8/99	5/10/99	
2.7-14	4/8/99	5/10/99	
2.7-15	4/16/99	5/10/99	
2.7-16	4/16/99	5/10/99	
3.2-1	11/25/98	2/17/99	
3.2-2	11/25/98	2/8/99	
3.2-3	11/25/98	2/8/99	
3.2-3	4/8/99	5/10/99	followon question
3.3-1	11/17/97	7/6/98	
3.3-2	11/17/97	7/6/98	
3.3-3	11/17/97	7/6/98	
3.3-4	11/17/97	7/6/98	
3.3-5	11/17/97	7/6/98	
3.3-6	11/17/97	7/6/98	
3.3-7	11/17/97	7/6/98	
3.3-8	11/17/97	7/6/98	
3.3-9	11/17/97	7/6/98	
3.3-10	11/17/97	7/6/98	
3.3-11	11/17/97	7/6/98	
3.3-12	11/17/97	7/6/98	
3.3-13	11/17/97	7/6/98	
3.3-14	11/17/97	7/6/98	
3.3-15	11/17/97	7/6/98	

Question Number	Issued	Response	Comments
3.3-16	11/17/97	7/6/98	
3.3-17	11/17/97	7/6/98	
3.3-18	11/17/97	7/6/98	
3.3-19	11/19/98	2/17/99	
3.3-19	4/8/99	5/10/99	followon question
3.3-20	11/19/98	2/8/99	
3.3-21	11/19/98	2/17/99	
3.3.3-1	4/8/99	5/10/99	
3.4.3-1	12/2/98	2/17/99	
3.4.3-2	4/8/99	5/10/99	
3.4.4-1	11/20/98	2/17/99	
3.4.5-1	11/20/98	2/17/99	
3.4.5-2	11/20/98	2/17/99	
3.4.5-3	11/20/98	2/17/99	
3.4.5-4	11/20/98	2/17/99	
3.4.5-5	11/20/98	2/17/99	
3.4.5-6	11/20/98	2/17/99	
3.4.5-7	11/20/98	2/17/99	
3.4.5-8	11/20/98	2/17/99	
3.4.5-9	4/8/99	5/10/99	
3.4.6-1	11/20/98	2/17/99	
3.4.6-2	11/20/98	2/17/99	
3.4.6-3	4/8/99	5/10/99	Duke did not provide a response to item A and C for this item. See item 3.4.3.3-4 for item A. See item 4.2.5.3-1 for item C
3.4.6-4	4/8/99	5/10/99	Duke did not provide a response to this item. See items 3.4.3.3-3, 3.4.3.3-5 and 3.4.3.3-6 for item A. See item 3.4.3.3-5 of this SER for item B.

Question Number	Issued	Response	Comments
3.4.6-5	4/8/99	5/10/99	Duke did not provide a response to this item. See item 3.4.3.3-4 of the SER
3.4.7-1	11/18/98	2/17/99	
3.4.7-1	4/8/99	5/10/99	followon question
3.4.7-2	11/18/98	2/17/99	
3.4.7-3	11/18/98	2/17/99	
3.4.7-4	12/3/98	2/17/99	
3.4.7-5	12/3/98	2/17/99	
3.4.8-1	11/18/98	2/17/99	
3.4.8-2	11/18/98	2/17/99	
3.4.8-3	11/18/98	2/17/99	
3.4.8-4	12/3/98	2/17/99	
3.4.8-5	12/3/98	2/17/99	
3.4.8-6	4/8/99	5/10/99	
3.4.10-1	11/18/98	1/25/99	
3.4.10-1	4/8/99	5/10/99	followon question. Duke did not provide a response to this item. See item 3.4.3.3-8 of the SER
3.4.10-2	11/18/98	1/25/99	
3.4.10-3	11/18/98	1/25/99	
3.4.10-4	11/18/98	1/25/99	
3.4.11-1	10/29/98	12/14/98	
3.4.11-2	10/29/98	12/14/98	
3.4.11-3	10/29/98	12/14/98	
3.4.11-4	10/29/98	12/14/98	
3.4.11-5	10/29/98	12/14/98	
3.4.11-6	10/29/98	12/14/98	
3.4.11-7	10/29/98	12/14/98	
3.5.2-1	12/3/98	2/8/99	

Question Number	Issued	Response	Comments
3.5.2-2	12/3/98	2/8/99	
3.5.3-1	11/18/98	1/25/99	
3.5.3-2	11/18/98	1/25/99	
3.5.3-3	12/3/98	2/8/99	
3.5.3-4	12/3/98	2/8/99	
3.5.3-5	12/3/98	2/8/99	
3.5.3-6	12/3/98	2/8/99	
3.5.3-7	12/3/98	2/8/99	
3.5.3-8	12/3/98	2/8/99	
3.5.4-1	11/24/98	2/8/99	
3.5.5-1	11/20/98	2/17/99	
3.5.5-2	12/3/98	2/8/99	
3.5.5-3	12/3/98	2/8/99	
3.5.6-1	11/18/98	1/25/99	
3.5.6-2	11/18/98	1/25/99	
3.5.7-1	11/18/98	1/25/99	
3.5.7-2	11/18/98	1/25/99	
3.5.7-3	4/8/99	5/10/99	
3.5.8-1	11/20/98	1/25/99	
3.5.8-2	11/20/98	1/25/99	
3.5.8-3	11/20/98	1/25/99	
3.5.8-3	4/8/99	5/10/99	followon question
3.5.8-4	11/20/98	1/25/99	
3.5.8-5	11/20/98	1/25/99	
3.5.8-6	11/20/98	1/25/99	
3.5.8-7	11/20/98	2/17/99	
3.5.8-8	12/3/98	2/8/99	

Question Number	Issued	Response	Comments
3.5.9-1	10/29/98	12/14/98	
3.5.9-2	10/29/98	12/14/98	
3.5.9-3	10/29/98	12/14/98	
3.5.9-4	10/29/98	12/14/98	
3.5.10-1	4/8/99	5/10/99	
3.5.12-1	12/3/98	2/8/99	
3.5.12-2	12/3/98	2/17/99	
3.5.13-1	11/18/98	1/25/99	
3.5.13-2	11/18/98	1/25/99	
3.5.14-1	11/18/98	1/25/99	
3.5.14-2	11/18/98	1/25/99	
3.5.14-3	11/18/98	1/25/99	
3.5.14-4	11/18/98	1/25/99	
3.5.14-4	4/8/99	5/10/99	followon question
3.5.14-5	12/3/98	2/17/99	
3.5.14-5	4/8/99	5/10/99	followon question
3.5.14-6	12/3/98	2/17/99	
3.5.14-6	4/8/99	5/10/99	followon question
3.5.14.7.1-1	4/8/99	5/10/99	
3.6-1	11/25/98	2/17/99	
3.6-2	11/25/98	2/17/99	
3.6-3	11/25/98	2/17/99	
3.6-4	11/25/98	2/17/99	
3.7.1-1	11/18/98	2/17/99	
3.7.1-2	11/18/98	2/8/99	
3.7.1-3	4/16/99	5/10/99	
3.7.1-4	4/16/99	5/10/99	

Question Number	Issued	Response	Comments
3.7.2-1	11/18/98	2/8/99	
3.7.2-2	12/3/98	2/8/99	
3.7.2-3	12/3/98	2/8/99	
3.7.3-1	11/30/98	2/8/99	
3.7.3-2	11/30/98	2/8/99	
3.7.3-2	4/8/99	5/10/99	followon question
3.7.3-3	11/30/98	2/8/99	
3.7.3-4	11/30/98	2/17/99	
3.7.3-5	11/30/98	2/8/99	
3.7.3-6	11/30/98	2/8/99	
3.7.3-7	11/30/98	2/17/99	
3.7.3-8	11/30/98	2/17/99	
3.7.3-9	11/30/98	2/8/99	
3.7.3-10	11/30/98	2/8/99	
3.7.3-11	11/30/98	2/8/99	
3.7.3-12	12/3/98	2/8/99	
3.7.4-1	11/18/98	2/8/99	
3.7.5-1	11/18/98	2/8/99	
3.7.5-2	11/18/98	2/17/99	
3.7.5-3	11/18/98	2/17/99	
3.7.6-1	11/30/98	2/8/99	
3.7.6-2	11/30/98	2/8/99	
3.7.6-3	11/30/98	2/17/99	
3.7.6-4	11/30/98	2/8/99	
3.7.6-5	11/30/98	2/17/99	
3.7.6-6	11/30/98	2/17/99	
3.7.7-1	11/18/98	2/8/99	

Question Number	Issued	Response	Comments
3.7.7-1	4/8/99	5/10/99	followon question
3.7.7-2	11/30/98	2/8/99	
3.7.7-2	4/8/99	5/10/99	followon question
3.7.7-3	11/30/98	2/17/99	
3.7.7-3	4/8/99	5/10/99	followon question
3.7.7-4	11/30/98	2/8/99	
3.7.7-5	11/30/98	2/17/99	
3.7.7-6	11/30/98	2/8/99	
3.7.7-6	4/8/99	5/10/99	followon question
3.7.7-7	11/30/98	2/8/99	
3.7.9-1	11/13/98	2/8/99	
3.7.9-2	11/13/98	2/17/99	
3.7.9-3	11/13/98	2/8/99	
4.3.1-1	11/20/98	2/17/99	
4.3.1-2	12/3/98	2/17/99	
4.3.1-3	12/3/98	2/17/99	
4.3.1-4	12/3/98	2/17/99	
4.3.1-5	12/3/98	2/17/99	
4.3.1-6	12/3/98	2/17/99	
4.3.2-1	10/29/98	12/14/98	
4.3.2-2	4/8/99	5/10/99	
4.3.7-1	11/20/98	2/17/99	
4.3.7-2	12/3/98	2/17/99	
4.3.7-3	4/16/99	5/10/99	
4.3.7-4	4/16/99	5/10/99	
4.3.7-5	4/16/99	5/10/99	
4.3.7-6	4/16/99	5/10/99	

Question Number	Issued	Response	Comments
4.3.7-7	4/16/99	5/10/99	
4.3.8-1	10/29/98	12/14/98	
4.3.8-2	10/29/98	12/14/98	
4.3.8-3	10/29/98	12/14/98	
4.3.8-4	10/29/98	12/14/98	
4.3.8-5	10/29/98	12/14/98	
4.3.8-6	10/29/98	12/14/98	
4.3.8-7	4/8/99	5/10/99	
4.3.8-8	4/8/99	5/10/99	
4.3.8-9	4/8/99	5/10/99	
4.3.9-1	10/29/98	12/14/98	
4.3.9-2	10/29/98	12/14/98	
4.3.9-3	10/29/98	12/14/98	
4.3.9-4	10/29/98	12/14/98	
4.3.9-5	10/29/98	12/14/98	
4.3.9-6	4/8/99	5/10/99	
4.3.9-7	4/8/99	5/10/99	
4.3.9-8	4/8/99	5/10/99	
4.3.13-1	12/3/98	2/17/99	
4.3.13-2	12/3/98	2/17/99	
4.3.13-3	12/3/98	2/17/99	
4.3.13-4	12/3/98	2/17/99	
4.5-1	12/3/98	2/8/99	
4.5-2	12/3/98	2/17/99	
4.5 (general)	3/25/99	4/6/99	Note: Additional general questions regarding Section 4.5 of the LRA were asked by the staff and answered by Duke in a 4/6/99 letter.
4.6.2-1	10/29/98	12/14/98	

Question Number	Issued	Response	Comments
4.6.2-2	10/29/98	12/14/98	
4.6.2-3	10/29/98	12/14/98	
4.6.2-4	10/29/98	12/14/98	
4.6.3-1	10/29/98	12/14/98	
4.6.3-2	10/29/98	12/14/98	
4.6.4-1	10/29/98	12/14/98	
4.8-1	11/19/98	2/8/99	
4.8-1	4/8/99	5/10/99	followon question
4.8-2	11/19/98	2/8/99	
4.8-3	11/19/98	2/8/99	
4.8-4	11/19/98	2/8/99	
4.9-1	12/1/98	2/8/99	
4.9-2	12/1/98	2/8/99	
4.9-3	12/4/98	2/8/99	
4.10-1	11/20/98	2/17/99	
4.11-1	12/3/98	2/8/99	
4.12-1	11/30/98	2/8/99	
4.12-2	11/30/98	2/8/99	
4.12-3	11/30/98	2/8/99	
4.13-1	12/1/98	2/17/99	
4.13-1	4/8/99	5/10/99	followon question
4.14-1	11/30/98	2/8/99	
4.14-2	11/30/98	2/8/99	
4.14-3	11/30/98	2/8/99	
4.15-1	11/18/98	2/8/99	
4.15-2	11/18/98	2/8/99	
4.15-3	11/18/98	2/8/99	

Question Number	Issued	Response	Comments
4.15-4	11/18/98	2/8/99	
4.15-5	11/30/98	2/8/99	
4.15-6	11/30/98	2/8/99	
4.16-1	12/4/98	2/8/99	
4.16-2	12/4/98	2/8/99	
4.16-3	12/4/98	2/17/99	
4.16-4	12/4/98	2/8/99	
4.16-5	12/4/98	2/8/99	
4.16-6	12/3/98	2/17/99	
4.16-7	12/4/98	2/8/99	
4.16-8	12/3/98	2/8/99	
4.16-9	12/3/98	2/8/99	
4.16-10	12/3/98	2/17/99	
4.16-10	4/8/99	5/10/99	followon question
4.16-11	12/3/98	2/17/99	
4.17-1	12/3/98	2/8/99	
4.17-1	4/8/99	5/10/99	followon question
4.17-2	12/3/98	2/17/99	
4.17-3	12/3/98	2/8/99	
4.17-4	4/8/99	5/10/99	Duke did not provide a response to a portion of this item. See item 3.2.12-2 of the SER
4.17-5	4/8/99	5/10/99	
4.17-6	4/8/99	5/10/99	Duke did not provide a response to a portion of this item. See item 3.2.12-1 of the SER
4.17-7	4/8/99	5/10/99	Duke did not provide a response to a portion of this item. See item 3.2.12-2 of the SER
4.17-8	4/8/99	5/10/99	
4.18-1	11/20/98	2/17/99	
4.18-2	12/2/98	2/17/99	

Question Number	Issued	Response	Comments
4.18-3	12/2/98	2/17/99	
4.18-4	12/2/98	2/17/99	
4.21-1	10/29/98	12/14/98	
4.21-2	10/29/98	12/14/98	
4.21-3	10/29/98	12/14/98	
4.21-4	10/29/98	12/14/98	
4.21-5	10/29/98	12/14/98	
4.21-6	11/18/98	1/25/99	
4.22-1	11/20/98	2/17/99	
4.23-1	12/2/98	2/8/99	
4.23-2	4/8/99	5/10/99	
4.23-3	4/8/99	5/10/99	
4.23-4	4/8/99	5/10/99	
4.25-1	12/3/98	2/17/99	
4.25-2	12/3/98	2/17/99	
4.25-3	4/8/99	5/10/99	
4.25-4	4/8/99	5/10/99	
4.25-5	4/8/99	5/10/99	Duke did not provide a response to this item. See item 3.2.13-1 of the SER
4.25-6	4/8/99	5/10/99	Duke did not provide a response to this item. See item 3.2.13-2 of the SER
4.25-7	4/8/99	5/10/99	Duke did not provide a response to this item. See item 3.2.13-3 of the SER
4.25-8	4/8/99	5/10/99	Duke did not provide a response to this item. See item 3.2.13-4 of the SER
4.26-1	12/3/98	2/17/99	
4.28-1	11/18/98	2/8/99	
4.28-2	11/18/98	2/8/99	
5.1-1	12/3/98	2/17/99	

Question Number	Issued	Response	Comments
5.3.1-1	11/19/98	2/8/99	
5.3.1-1	4/8/99	5/10/99	followon question. Duke did not provide a response to this item. See item 4.2.1.3-1 of the SER
5.3.1-2	11/19/98	2/8/99	
5.3.2-1	11/19/98	2/8/99	
5.3.2-2	11/19/98	2/8/99	
5.3.2-2	4/8/99	5/10/99	followon question
5.4.1-1	11/24/98	2/17/99	
5.4.1-2	11/24/98	2/17/99	
5.4.1-3	11/24/98	2/17/99	
5.4.1-3	4/8/99	5/10/99	followon question
5.4.1-4	11/24/98	2/17/99	
5.4.1-4	4/8/99	5/10/99	followon question
5.4.1-5	11/24/98	2/17/99	revised Duke response 3/29/99
5.4.1-6	4/16/99	5/10/99	Duke did not provide a response to a portion of this item. See item 4.2.3-1 of the SER
5.4.2-1	11/20/98	2/17/99	
5.6-1	11/25/98	2/8/99	
5.6-2	11/25/98	2/8/99	
5.6-3	11/25/98	2/8/99	
5.7.1-1	10/29/98	12/14/98	
5.7.1-2	4/8/99	5/10/99	
5.7.2-1	12/2/98	2/8/99	

NRC FORM 335 (2-89) NRCM 1102, 3201, 3202

U.S. NUCLEAR REGULATORY COMMISSION

BIBLIOGRAPHIC DATA SHEET

(See instructions on the reverse)

1. REPORT NUMBER (Assigned by NRC, Add Vol., Supp., Rev., and Addendum Numbers, if any.)

NUREG-1723

2. TITLE AND SUBTITLE

Safety Evaluation Report
Related to the Licensee Renewal of
Oconee Nuclear Station, Units 1, 2, and 3

Docket Nos. 50-269, 50-270 and 50-287

3. DATE REPORT PUBLISHED

MONTH	YEAR
March	2000

4. FIN OR GRANT NUMBER

5. AUTHOR(S)

6. TYPE OF REPORT

Technical

7. PERIOD COVERED *(Inclusive Dates)*

8. PERFORMING ORGANIZATION - NAME AND ADDRESS *(If NRC, provide Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address; if contractor, provide name and mailing address.)*

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

9. SPONSORING ORGANIZATION - NAME AND ADDRESS *(If NRC, type "Same as above"; if contractor, provide NRC Division, Office or Region, U.S. Nuclear Regulatory Commission, and mailing address.)*

Same as item 8. above

10. SUPPLEMENTARY NOTES

Docket Numbers 50-269, 50-270 and 50-287

11. ABSTRACT *(200 words or less)*

This safety evaluation report documents the technical review of the Oconee Nuclear Station (ONS), Unit Nos. 1, 2 and 3 license renewal application (LRA) by the U.S. Nuclear Regulatory Commission staff. By letter dated July 6, 1998, Duke Energy Corporation submitted the license renewal application for the ONS in accordance with Title 10 of the Code of Federal Regulations Part 54 (10 CFR Part 54).

On the basis of its evaluation of the LRA, the staff concludes that: (1) actions have been identified and have been or will be taken with respect to managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified and have been or will be taken with respect to time-limited aging analyses that have been identified to require review under 10 CFR 54.21(c). Accordingly, the staff finds that there is reasonable assurance that the activities authorized by a renewed license will continue to be conducted in accordance with the current licensing basis for the ONS, Unit Nos. 1, 2, and 3 during the period of extended operation.

12. KEY WORDS/DESCRIPTORS *(List words or phrases that will assist researchers in locating the report.)*

License Renewal
Part 54
Oconee Nuclear Station
Safety Evaluation Report
50-269
50-270
50-287
scoping
aging management
time-limited aging analyses

13. AVAILABILITY STATEMENT

unlimited

14. SECURITY CLASSIFICATION

(This Page) unclassified

(This Report) unclassified

15. NUMBER OF PAGES

16. PRICE

NRC FORM 335 (2-89)

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NUCLEAR REGULATORY COMMISSION
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