APPLICATION FOR RENEWED OPERATING LICENSES

OCONEE NUCLEAR STATION, UNITS 1, 2, AND 3

Volume III

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4. AGING MANAGEMENT PROGRAMS AND ACTIVITIES

4.1 INTRODUCTION

As described previously in Section 1.2 of OLRP-1001, four major activities comprise the *Oconee Integrated Plant Assessment*. The first two activities, "Identification of Structures & Components that are Subject to Aging Management Review," and "Identification of Applicable Aging Effects," have been described previously in Chapters 2 and 3 of OLRP-1001, respectively. The third major activity of the *Oconee Integrated Plant Assessment* is the identification of plant-specific programs and activities that will manage identified applicable aging effects. These programs and activities are described in OLRP-1001 Chapter 4, "Aging Management Programs and Activities." The fourth major activity of the *Oconee Integrated Plant Assessment*, the aging management demonstration for existing programs and activities, also is presented in Chapter 4.

Oconee programs and activities that are credited during the aging management review are described in the remaining sections of Chapter 4. The demonstrations, along with the program and activity descriptions, meet the requirement specified in §54.21(a)(3). Along with the technical information contained in Chapters 2 and 3, this chapter is designed to allow the NRC to make the finding contained in §54.29(a)(1).

§54.29 Standards for issuance of a renewed license

A renewed license may be issued by the Commission up to the full term authorized by §54.31 if the Commission finds that:

(a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:

(1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under §54.21(a)(1); and

(2) time-limited aging analyses that have been identified to require review under §54.21(c).

(b) Any applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied.

(c) Any matters raised under §2.758 have been addressed.

The Oconee programs and activities that are credited for managing aging may be divided into new actions not currently being conducted and existing ongoing actions. Some of the existing programs and activities have an established regulatory basis. The new programs and activities are described in Section 4.3, and the existing programs and activities are described in Sections 4.4 through 4.29. These descriptions of programs and activities are intended to provide an overview of the range of actions required to manage aging. Some of the descriptions have used a series of specific attributes to facilitate the description of the actions. These attributes are defined in Section 4.2.

Descriptions of new and existing programs and activities are contained in the Oconee *UFSAR Supplement for License Renewal*, which is provided in Exhibit B of the Application. The *UFSAR Supplement for License Renewal* will be incorporated into the Oconee UFSAR following issuance of the Oconee renewed operating licenses by the NRC. Upon inclusion of descriptions of these programs and activities in the Oconee UFSAR, changes to the descriptions will be made in accordance with the change process in effect at the time of any such change.

4.2 PROGRAM AND ACTIVITY ATTRIBUTES

Attributes that are utilized in most of the program and activity descriptions for license renewal, with a few exceptions [Footnote 1], are described in Section 4.2. The following information sources served as primary inputs to the attribute definitions used in Chapter 4:

1. NEI 95-10, Revision 0, Sections 4.2 and 4.3 [Reference 4.2-1]
2. Working Draft Standard Review Plan, Section 3.0 [Reference 4.2-2]
3. August 13, 1997, letter from the NRC to Duke Power--Comments on the License Renewal Inspection Program Example on the Reactor Coolant System Flow Nozzle [Reference 4.2-3]

The attribute definitions used to describe new and existing programs and activities are provided below.

Purpose - A clear statement of the reason why the program or activity exists for Oconee license renewal.

Scope - A description of the set of Oconee structures and components encompassed by the actions of the program or activity.

Aging Effects - A description of the applicable aging effects to be managed or the relevant physical conditions to be monitored for the identified scope of structures and components.

Method - A description of the type of action or technique used to identify or manage the aging effects or relevant conditions (e.g., visual examination of the component).

Sample Size - For new programs or activities, a sample population can be identified from the total population of affected structures and components for inspection or monitoring. If a sample population is chosen for inspection or monitoring, a description of the sample population is provided.

1. The following programs are described in a narrative style rather than using the attributes: the Coatings Program, which is a special process as defined in the Duke Quality Assurance Program; the Chemistry Control Program, which contains more detail than can be included in this report; the Duke Quality Assurance Program and the Reactor Vessel Internals Aging Management Program, which is a long term developmental program.

Industry Codes or Standards - A description of an industry code (e.g., ASME Section XI, IEEE) or an industry standard (e.g., ASTM or NRC-approved BWOG report) that guides or governs the program or activity. This attribute may not be applicable to some programs and activities.

Frequency - A description of the frequency of action that is established detection of aging effects or of relevant physical conditions.

Acceptance Criteria or Standard - Acceptance criteria or standards are described for the relevant conditions to be monitored or the chosen examination methods.

Corrective Action - A description of the action to be taken when the established acceptance criteria or standard is not met. Generally, the *Duke Quality Assurance Program* is applicable.

Timing of New Program or Activity - For any new programs or activities, an identification of the specific timing for the new program or activity.

Administrative Controls - An identification of the Oconee administrative structure under which the programs and activities are executed. The *Duke Quality Assurance Program* is applicable.

Regulatory Basis - For existing programs and activities, an identification of any existing Oconee regulatory basis for these actions such as the Technical Specifications. This attribute may be not applicable to some programs and activities.

4.2.1 References for Section 4.2

4.2-1. *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,* NEI 95-10, Revision 0, Nuclear Energy Institute, March 1996.

4.2-2. *Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants,* Working Draft, NRC, September 1997.

4.2-3. S. T. Hoffman (NRC) letter dated August 13, 1997, to W. R. McCollum (Duke), *License Renewal Inspection Program Example for Oconee Nuclear Station, Units 1, 2, and 3,* Docket Nos. 50-269, -270, and -287.

4.3 NEW PROGRAMS AND ACTIVITIES

The *Oconee Integrated Plant Assessment* for license renewal identified several new programs and activities that currently do not exist, but are nevertheless necessary to continue operation of Oconee during the additional 20-years beyond the initial license term. Section 4.3 describes these programs and activities. They are commitments that will be implemented following issuance of the renewed operating licenses for Oconee Nuclear Station.

4.3.1 Alloy 600 Aging Management Program

Section 2.4 of OLRP-1001 identifies several Alloy 600 and Alloy 82/182 components of the Reactor Coolant System. Section 3.4 of OLRP-1001 identifies cracking due to primary water stress corrosion (PWSCC) as an applicable aging effect. The *Alloy 600 Aging Management Program* in conjunction with the *Chemistry Control Program* (see Section 4.6), *Inservice Inspection Plan* (see Section 4.18), and *Reactor Coolant System Operational Leakage Monitoring* (see Section 4.23), will manage the applicable aging effect for the period of extended operation. The *Alloy 600 Aging Management Program* will have the attributes.

Purpose - The purpose of the Oconee *Alloy 600 Aging Management Program* will be to manage cracking due to PWSCC of Alloy 600 and Alloy 82/182 locations, including the Alloy 82/182 cladding in the hot leg flowmeter element, for the period of extended operation.

Scope - The results of the *Alloy 600 Aging Management Program* will be applicable to the Alloy component 600 material and Alloy 82/182 weld material in the Oconee Reactor Coolant System, including the hot leg flowmeter element. [Footnote 2]

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2. Renewal Applicant Action Item in the NRC SER concerning the "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," BAW-2243A states that:

"The BWOG defers the development of 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, to the renewal applicant referencing this topical report. The renewal applicant will have to provide details of these … inspection programs in its renewal application for staff review and approval."

Renewal Applicant Action Item 5 in the NRC SER concerning the "Demonstration of the Management of Aging Effects for the Pressurizer," BAW-2244A states that:

"Since the B&WOG defers the development of details of the sample volumetric inspection program of small-bore nozzles and safe ends to the renewal applicant referencing this topical report, the renewal applicant will have to provide details of the additional sample inspection program in its renewal application for staff review and approval."

[Reference Chapter 2.4 of OLRP-1001, Table 2.4-2].

The *Alloy 600 Aging Management Program* is intended to address these Renewal Applicant Action Items regardless of whether or not the hot leg segment is included in the inspection locations selected.

Aging Effects - The applicable aging effect for the scope of the *Alloy 600 Aging Management Program* is primary water stress corrosion cracking (PWSCC) of Alloy 600 components and Alloy 82/182 weld metal in the Reactor Coolant System at Oconee.

Method - The exact inspection method will be dependent on the geometry of the inspection locations. Inspection methods will involve a combination of surface and volumetric examinations which may include eddy current testing, ultrasonic testing, and radiography.

Sample Size - To determine the initial inspection locations, the Oconee *Alloy 600 Aging Management Program* will, first, complete a susceptibility study of Alloy 600 components and Alloy 82/182 weld locations in the Reactor Coolant System. Upon completion and validation of this susceptibility study, the top three or four locations will have detailed inspection plans developed and implemented to monitor the condition of these locations. Monitoring the most susceptible locations will bound the Alloy 600 component locations and the Alloy 82/182 weld locations that are not inspected.

Industry Code or Standards - ASME Section XI, 1989 Edition, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 1989 Addenda).

Frequency - The frequency will be based on findings of the initial inspections. An analysis will be completed at each of the selected locations that will determine crack propagation rates. The time for an indication to grow from a newly initiated indication to a through wall crack will determine the inspection frequency.

Acceptance Criteria or Standard - Acceptance criteria for identified flaws will be based on crack propagation rates, which vary from location to location based on the calculated residual and operating stresses for the particular location using approved fracture mechanics techniques. In past inspections, after measuring the depth of the indications, small cracks have been allowed to remain in service without immediate repair when the calculated crack growth rate plus the measured depth of the indication predicted no through wall leak (or other acceptance criteria agreed to by the NRC) will occur prior to corrective action being taken or the crack otherwise being dispositioned.

Corrective Action - Corrective actions will be developed and implemented on a case-by-case basis at Oconee depending on the nature of the inspection findings. A complete, full replacement or a repair in accordance with ASME Section XI may be appropriate for some locations. Taking no immediate action on the indication and monitoring with further inspections may also be appropriate.

Both the sample size and number of locations will be re-evaluated following the completion of each inspection with documentation of these re-evaluations completed on an annual basis once the inspections begin. Additional inspection locations may be added to the list based on a qualitative assessment of risk.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2103 (the end of the initial license term for Oconee Unit 1).

Administrative Controls - The *Alloy 600 Aging Management Program* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - BAW-2243A, [Reference 4.3-1] and BAW-2244A, Action Item 5 [Reference 4.3-2]. [Footnote 3]

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3. Renewal Applicant Action Item in the NRC SER concerning the "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," BAW-2243A states that:

> "The BWOG defers the development of 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, to the renewal applicant referencing this topical report. The renewal applicant will have to provide details of these … inspection programs in its renewal application for staff review and approval."

Renewal Applicant Action Item 5 in the NRC SER concerning the "Demonstration of the Management of Aging Effects for the Pressurizer," BAW-2244A states that:

> "Since the B&WOG defers the development of details of the sample volumetric inspection program of small-bore nozzles and safe ends to the renewal applicant referencing this topical report, the renewal applicant will have to provide details of the additional sample inspection program in its renewal application for staff review and approval."

[Reference Chapter 2.4 of OLRP-1001, Table 2.4-2].

The *Alloy 600 Aging Management Program* is intended to address these Renewal Applicant Action Items regardless of whether or not the hot leg segment is included in the inspection locations selected.

4.3.2 Cast Iron Selective Leaching Inspection

Section 2.5 of OLRP-1001 identifies the cast iron mechanical components that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to selective leaching as an applicable aging effect. Components constructed of cast iron are susceptible to loss of material due to selective leaching when in contact with either water, soil, or groundwater. Monitoring components susceptible to selective leaching has not typically been performed by the industry and, at the time of Application, research concerning the phenomenon is ongoing. The *Cast Iron Selective Leaching Inspection* will have the following attributes.

Purpose - The purpose of the *Cast Iron Selective Leaching Inspection* will be to characterize loss of material due to selective leaching for cast iron components in Oconee raw water, treated water, and underground environments.

Scope - The results of this inspection will be applicable to the cast iron components falling within the scope of license renewal. These components include pump casings in several systems along with piping, valves and other components. As identified in Sections 3.5.3 through 3.5.14, the Oconee raw and treated water systems containing cast iron components potentially susceptible to loss of material due to selective leaching are the Auxiliary Service Water System, the Condensate System, the Condenser Circulating Water System, the Service Water System (Keowee), and the High Pressure Service Water System.

Aging Effects - The inspection will determine the existence of loss of material due to selective leaching, a form of galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function. Selective leaching is the dissolution of iron at the metal surface that leaves a weakened network of graphite and iron corrosion products.

Method - The *Cast Iron Selective Leaching Inspection* will inspect a select set of cast iron pump casings to determine whether selective leaching of the iron has been occurring at Oconee and whether loss of material due to selective leaching will be an aging effect of concern for the period of extended operation. A Brinnell Hardness check will be performed on the inside surface of a select set of cast iron pump casings to determine if this phenomenon is occurring. The results of the *Cast Iron Selective Leaching Inspection* will be applicable to all cast iron components within license renewal scope and installed in applicable environments.

Sample Size - Five pump casings will be inspected for evidence of selective leaching, one from each of the following systems on-site:

- Auxiliary Service Water System
- Condensate System
- High Pressure Service Water System
- Service Water System (Keowee)
- Condensate System (one inspection location on any of the three Oconee Units.)

Industry Codes or Standards - No specific codes or standards exist to address this inspection.

Frequency - The *Cast Iron Selective Leaching Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to selective leaching as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Corrective Action - Any unacceptable loss of material due to selective leaching requires an engineering analysis be performed to determine potential impact on component intended function.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Cast Iron Selective Leaching Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This one-time inspection activity has no current regulatory basis.

4.3.3 GALVANIC SUSCEPTIBILITY INSPECTION

Section 2.5 of OLRP-1001 identifies the carbon steel, cast iron, copper alloy and stainless steel mechanical components that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to galvanic corrosion of carbon steel and cast iron components when coupled with either copper alloys or stainless steels as an applicable aging effect. Section 3.5 also identifies loss of material due to galvanic corrosion of copper alloys when coupled to stainless steels as an applicable aging effect. A review of over 200 metallurgical inspection records for Oconee that date from 1981 was conducted. From this review, no failures from galvanic corrosion have been documented. The susceptibility and aggressiveness of galvanic corrosion is determined by the material position on the galvanic series and the corrosiveness of the surrounding environment. Since inspection of all couples is impractical, only certain locations will be inspected where galvanic corrosion is more likely to occur. These more susceptible locations are where the materials are the farthest apart on the galvanic series surrounded by the most corrosive environment in the plant. For the couples noted above, carbon steel and stainless steel are the farthest apart on the galvanic series and raw water is the most corrosive environment. An inspection of selected locations of carbon steel - stainless steel connections in the Oconee raw water systems will determine whether loss of material due to galvanic corrosion will be an aging effect of concern for the period of extended operation. The evidence gained from the piping examinations will be indicative of the condition of the carbon steel - stainless steel, carbon steel - copper alloy, and copper alloy - stainless steel connections throughout Oconee. The results of the *Galvanic Susceptibility Inspection* will determine the need for additional programmatic oversight to manage this aging effect. The *Galvanic Susceptibility Inspection* will have the following attributes.

Purpose - The purpose of the *Galvanic Susceptibility Inspection* will be to characterize the loss of material by galvanic corrosion in carbon steel - stainless steel couples in the Oconee raw water systems.

Scope - The results of this inspection will be applicable to all galvanic couples with the focus on the carbon steel - stainless steel couples in the Oconee raw water systems falling within the scope of license renewal.

Aging Effects - The inspection will determine the existence of loss of material due to galvanic corrosion and assess the likelihood of the impact of this aging effect on the component intended function.

Method - A volumetric examination at the junction of the carbon steel - stainless steel components is needed to determine material loss from the more anodic carbon steel. At the time of Application, a destructive examination of the more susceptible locations chosen to be the sentinel population would be an acceptable examination method. Other volumetric techniques may also be effective with the exact method of examination to be selected at the time of inspection.

Sample Size - A sentinel population of the more susceptible locations on all three Oconee units, Keowee, and Standby Shutdown Facility will be selected for this inspection from the following raw water systems within the scope of license renewal.

- Auxiliary Service Water System
- Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal)
- Condenser Circulating Water System
- High Pressure Service Water System
- Low Pressure Injection (raw water portion of the Decay Heat Removal Cooler)
- Low Pressure Service Water System
- Service Water System (Keowee)
- Turbine Generator Cooling Water System (Keowee)
- Turbine Sump Pump System (Keowee)
- Standby Shutdown Facility Auxiliary Service Water System

Areas of low to stagnant flow in Oconee raw water systems which contain carbon steel - stainless steel couples are the most susceptible locations. Engineering practice at Duke has been to use stainless steel as a replacement material in raw water systems for several years. Since engineering practice will continue to use stainless steel as an acceptable substitute material, the size of the sentinel population will be dependent on the number of susceptible locations at the time of the inspection.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Frequency - The *Galvanic Susceptibility Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to galvanic corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss due of material due to galvanic corrosion requires that an engineering analysis be performed to determine potential impact on component intended function.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Galvanic Susceptibility Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This inspection has no current regulatory basis.

4.3.4 KEOWEE AIR AND GAS SYSTEMS INSPECTION

Section 2.5 of OLRP-1001 identifies the carbon steel mechanical components in the Keowee Carbon Dioxide, Depressing Air, and Governor Air Systems that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to general corrosion of the carbon steel components in the Keowee Carbon Dioxide, Depressing Air, and Governor Air Systems as an applicable aging effect. Condensation from the internal air environment may provide the conditions for general corrosion of the carbon steel components. The *Keowee Air and Gas Systems Inspection* will have the following attributes.

Purpose - The purpose of the *Keowee Air and Gas Systems Inspection* will be to characterize the loss of material due to general corrosion of the carbon steel components within the Carbon Dioxide, Depressing Air, and Governor Air Systems at Keowee that may be exposed to condensation.

Scope - The results of this inspection will be applicable to the carbon steel components within the license renewal portion of the Carbon Dioxide, Depressing Air, and Governor Air Systems on each unit at Keowee.

Aging Effects - The inspection will determine the existence of loss of material due to general corrosion of carbon steel components in the Carbon Dioxide, Depressing Air, and Governor Air Systems. The inspection will assess the likelihood of the impact of this aging effect on the component intended function.

Method - An inspection of select portions of the each system will determine whether loss of material due to general corrosion will be an aging effect of concern for the period of extended operation. The results *Keowee Air and Gas Systems Inspection* will determine the need for additional programmatic oversight to manage this aging effect.

For the Carbon Dioxide System, the discharge piping low elevation point will be determined. A volumetric examination will conducted on a portion of carbon steel pipe in and around this low point of the Carbon Dioxide System.

For the Depressing Air System, a volumetric examination will be conducted on a portion of piping between the control valves and the Keowee unit turbine head cover.

For the Governor Air System, a visual examination of the bottom half of the interior surface of the air receiver tanks will determine the presence of corrosion. The visual examination will also serve to characterize any instance of corrosion. Piping between the air receiver tank and the governor oil pressure tank will receive a volumetric examination.

Sample Size - For the Carbon Dioxide System, the inspection will include four feet of pipe around the system low elevation point (two feet upstream and downstream).

For the Depressing Air System, the inspection will include one of the two four-foot sections of piping between the control valves and the Keowee unit headcover.

For the Governor Air System, the inspection will include the lower half of each Air Receiver Tank and one of the two four-foot sections of the piping between the air receiver tanks and the governor oil pressure tanks.

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The *Keowee Air and Gas Systems Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to corrosion as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to corrosion will require that an engineering analysis be performed to determine proper corrective action.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Governor Air System Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This inspection has no current regulatory basis.

4.3.5 Keowee Oil Sampling Program

Three of the four Keowee oil systems are within the scope of license renewal. Section 2.5.13 of OLRP-1001 identifies the carbon steel and stainless steel mechanical components in the Generator High Pressure Oil System, Governor Oil System and the Turbine Guide Bearing Oil System that are subject to aging management review.

Section 3.5.13 of OLRP-1001 identifies that loss of material due to general and galvanic corrosion of the carbon steel components and loss of material due to pitting corrosion of the carbon steel and stainless steel components in the Governor Oil System could occur due to the presence of water in the lower portions of the system. Section 3.5.13 also identifies that loss of material due to microbiologically influenced corrosion of the stainless steel tubes and tubesheets of the Turbine Guide Bearing Oil Cooler exposed to raw water could occur. No aging effects are identified for the Generator High Pressure Oil System.

The *Keowee Oil Sampling Program* will manage loss of material for the carbon steel and stainless steel components in the Governor Oil System and Turbine Guide Bearing Oil System. The *Keowee Oil Sampling Program* was only recently formalized, and therefore, the program is considered a new program for license renewal. The *Keowee Oil Sampling Program* will have the following attributes.

Purpose - The purpose of the *Keowee Oil Sampling Program* will be to monitor and control the water contamination levels in the Governor Oil System to preclude loss of material for the carbon steel and stainless steel components in the scope of license renewal. In addition, the *Keowee Oil Sampling Program* will manage loss of material of the stainless steel subcomponents in the Turbine Guide Bearing Oil System by monitoring the Turbine Guide Bearing Oil System for water contamination.

Scope - The scope of the *Keowee Oil Sampling Program* includes all carbon steel and stainless steel components within the scope of license renewal in the Governor Oil System and the turbine guide bearing oil coolers, the only stainless steel component of concern in the Turbine Guide Bearing Oil System. This program will contain elements which cover all four Keowee oil systems and, as such, is intended to cover a broader scope than is being credited for license renewal.

Aging Effects - Water contamination in the Governor Oil System can expose the carbon steel and stainless steel components to conditions conducive to loss of material due to various forms of corrosion. Water contamination in the Turbine Guide Bearing Oil System is evidence of leakage of the Turbine Guide Bearing Oil Cooler from loss of material due to microbiologically influenced corrosion. Monitoring and controlling water contamination precludes this applicable aging effect in the Governor Oil System and manages this applicable aging effect in the Turbine Guide Bearing Oil Coolers.

Method - The *Keowee Oil Sampling Program* will require that the Governor Oil System Sump and Turbine Guide Bearing Oil System reservoirs be sampled for the presence of water contamination.

Sample Size - This criteria is not applicable, since relevant conditions are being monitored and not system hardware.

Industry Codes or Standards - ASTM D95-83, *Water in Petroleum and Bitumens*, provides guidance for the testing of the oil sample.

Frequency - Oil samples will be taken and analyzed every six months. Results of the analysis will be monitored and trended.

Acceptance Criteria or Standard - No water contamination in excess of 0.1% water by volume will be the limit for water contamination in the Governor Oil System and Turbine Guide Bearing Oil System.

Corrective Action - If water contamination levels exceed the acceptance criteria, the accountable engineer will be notified and the source of the water contamination will be located and corrected. The contaminated oil will be sent to the plant oil purifier to remove the water and returned to the system.

Specific corrective actions will be made in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - Following issuance of a renewed operating license for Oconee Nuclear Station, the *Keowee Oil Sampling Program* will be implemented by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Administrative Control - The *Keowee Oil Sampling Program* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This program has no current regulatory basis.

4.3.6 Once Through Steam Generator Upper Lateral Support Inspection

Section 2.4 of OLRP-1001 identifies the Once Through Steam Generator (OTSG) upper lateral supports. Section 3.4 of OLRP-1001 identifies cracking of the lubrite pads as an applicable aging effect. The *OTSG Upper Lateral Support Inspection* will have the following attributes.

Purpose - The purpose of the *OTSG Upper Lateral Support Inspection* is to determine whether cracking of the OTSG upper lateral support lubrite pads has occurred and to validate that the condition of the lubrite pads is acceptable for the period of extended operation.

Scope - The results of this inspection will be applicable to all thirty lubrite pads installed at Oconee (ten per unit).

Aging Effects - The applicable aging effect is cracking of the lubrite pads by gamma irradiation.

Method - A visual inspection of the accessible surfaces of a sample population of lubrite pads will be performed to determine if the pads are cracking.

Sample Size - The sample size will be five lubrite pads on one OTSG upper lateral support.

Industry Codes or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The *OTSG Upper Lateral Support Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No cracks in the lubrite pads.

Corrective Action - If the sample lubrite pads are cracked, then the affected pads must be replaced and the remaining 25 lubrite pads must be inspected.

Lubrite pads that are cracked will be replaced with new pads.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *OTSG Upper Lateral Support Inspection* will be implemented in accordance with written procedures as required by the *Duke Quality Assurance Program.*

Regulatory Basis - This one-time inspection has no current regulatory basis.

4.3.7 PRESSURIZER EXAMINATIONS

Section 2.4 of OLRP-1001 identifies the pressurizer as subject to aging management review. Section 3.4 of OLRP-1001 and BAW-2244A [Reference 4.3-2] identify the following aging effects that will require new or additional inspections for license renewal: (1) cracking of pressurizer cladding and, including items attached to the cladding (e.g., tripod legs), which 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 Oconee-specific review identified cracking of internal spray line and spray head as requiring a one-time inspection. Aging management of the pressurizer Alloy 600 small bore nozzles is addressed in the *Alloy 600 Aging Management Program* (See Section 4.3.1). Small bore safe ends are addressed in the *Small Bore Piping Inspections* (See Section 4.3.12). The *Pressurizer Examinations* include two specific examinations: (1) the pressurizer cladding, internal spray line, and spray head; and (2) the pressurizer heater penetration weld examination, which are described in the following sections.

4.3.7.1 Pressurizer Cladding, Internal Spray Line, and Spray Head Examination

The *Pressurizer Cladding, Internal Spray Line, and Spray Head Examination* will have the following attributes.

Purpose - The purpose of the *Pressurizer Cladding, Internal Spray Line, and Spray Head Examination* will be to assess the condition of the pressurizer cladding, internal spray line, and spray head.

Scope - The scope of this activity will include the cladding and attachment welds to the cladding of all three pressurizers at the Oconee units and to the internal spray line and spray head of all three pressurizers at the Oconee units, including the fasteners that connect the spray line and spray head to the internal surface of the pressurizer.

Aging Effects - The aging effects of concern are cracking of cladding by thermal fatigue, which may propagate to the underlying ferritic steel. Cracking of the internal spray line by fatigue and cracking of the spray head due to reduction of fracture toughness are also aging effects.

Method - Visual examination (VT-3) of the clad inside surfaces of the pressurizer (100% coverage of the accessible surface) including attachment welds to the pressurizer will be performed. Historical data (Haddam Neck) indicates cracking may occur adjacent to the heater bundles, if at all. Therefore, the examination will focus on cladding adjacent to the heater bundles. In addition, visual inspections have been shown to be adequate for detecting cracks in cladding at Haddam Neck; cracking that extended to underlying ferritic steel was found due to the observance of rust.

Visual examination (VT-3) of the internal spray line and spray head, including the fasteners that are used to attach the spray line to the internal surface of the pressurizer will also be performed.

Sample Size - The examination will be performed on the cladding (100% coverage of the accessible surface), spray head, and internal spray line of one pressurizer at Oconee.

Industry Code or Standards - ASME Section XI, 1989 Edition, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 1989 Addenda).

Frequency - The *Pressurizer Cladding, Internal Spray Line, and Spray Head Examination* is a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for visual examinations will be in accordance with ASME Section XI VT-3 examinations.

Corrective Action - 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 applicable to subsequent volumetric examination of 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 corrective actions that could include replacement of the spray head.

The need for subsequent examinations will be determined after the results of the initial examination are available.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - Inspections and engineering evaluations will be performed in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Renewal Applicant Action Item 4.2 (1) in the Safety Evaluation for BAW-2244A (See Table 2.4-3 of OLRP-1001).

4.3.7.2 Pressurizer Heater Bundle Penetration Welds Examination

The *Pressurizer Heater Bundle Penetration Welds Examination* will have the following attributes.

Purpose - This purpose of the *Pressurizer Heater Bundle Penetration Welds Examination* will be to assess the condition of the pressurizer heater penetration welds.

Scope - The results of this examination will be applicable to the heater sheath-to-sleeve or heater sheath-to-diaphragm plate penetration welds for the pressurizer heater bundles. Each pressurizer contains three heater bundles.

Aging Effects - The aging effect of concern is cracking at heater bundle penetration welds which may lead to coolant leakage.

Method - For the heater bundle that is removed, a surface examination of sixteen peripheral welds on one bundle will be performed. A visual examination (VT-3 or equivalent) of the remaining welds of the heater bundle will be performed. [Footnote 4]

Sample Size - The examination will include sixteen peripheral heater penetration welds on one heater bundle in one of the Oconee units, whichever heater bundle is removed first.

Industry Code or Standards - ASME Section XI, 1989 Edition, including mandatory Appendices VII and VIII (Appendix VIII in accordance with 1989 Addenda).

Frequency - The *Pressurizer Heater Bundle Penetration Welds Examination* is a one-time inspection.

Acceptance Criteria or Standard - Acceptance standards for surface examinations and visual examination (VT-3) will be in accordance with ASME Section XI.

Corrective Action - If the results of the inspection are not acceptable, then the results may be used as a baseline inspection for establishing a longer term programmatic action covering all Oconee pressurizer heater bundles.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

4. The Oconee *Inservice Inspection Plan* for the 5th inservice inspection interval will include pressurizer heater bundle welds under Examination Category B-E or equivalent (see Section 4.18).

Timing of New Program or Activity - The surface examinations of the sixteen peripheral heater penetration welds will be performed upon removal of a pressurizer heater bundle.

Administrative Controls - Inspections and engineering evaluations will be performed in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Renewal Applicant Action Item 4.2 (2) in the Safety Evaluation for BAW-2244A (See Table 2.4-3 of OLRP-1001).

4.3.8 Preventive Maintenance Activity Assessment

As described in the Oconee UFSAR Chapter 13.5.2.2.1, Maintenance Procedures, maintenance of station safety-related structures, systems, and components is performed in accordance with written procedures, documented instructions, or drawings which conform to applicable codes, standards, specifications, and criteria. For license renewal, an assessment of several specific preventive maintenance activities which manage a variety of applicable aging effects for the license renewal will be performed. The *Preventive Maintenance Activity Assessment* will have the following attributes.

Purpose - The purpose of the *Preventive Maintenance Activity Assessment* will be to assess the effectiveness of existing plant maintenance activities identified in Table 4.3-1.

Scope - The *Preventive Maintenance Activity Assessment* will include an assessment of the effectiveness of the maintenance activities listed in Table 4.3-1.

Aging Effects - The applicable aging effects that have been identified for license renewal are listed in Table 4.3-1.

Method - The *Preventive Maintenance Activity Assessment* will be conducted in accordance with the requirements for performing self-assessments as described in Chapter 17.3.3, *Self Assessments,* of the *Duke Quality Assurance Program Topical Report.*

Sample Size - Each of the above maintenance activities will be assessed.

Industry Codes or Standards - No code or standard exist to guide or govern this assessment.

Frequency - The *Preventive Maintenance Activity Assessment* is a one-time assessment.

Acceptance Criteria or Standard - The *Duke Quality Assurance Program.*

Corrective Action - The maintenance activities identified in Table 4.3-1 are effective in managing the aging effects and that the component intended functions are being maintained under all current licensing basis conditions for the period of extended operation. If the *Preventive Maintenance Activity Assessment* determines that enhancements to one or more of the maintenance activities listed in Table 4.3-1 are required, then corrective actions will be implemented.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Preventive Maintenance Activity Assessment* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - 10 CFR §50.65, *Requirements for monitoring the effectiveness of maintenance at nuclear power plants.*

Table 4.3-1 Preventive Maintenance Activities

Preventive Maintenance Activity	Aging Effect
Auxiliary Service Water Piping Inspection	Fouling due to macro-organisms and silting has been identified as an applicable aging effect for specific portions of the Auxiliary Service Water System piping that can not be periodically tested.
Borated Water Storage Tank Internal Coatings Inspection	Loss of material due to general and localized corrosion has been identified as an applicable aging effect for the carbon steel borated water storage tank in the Low Pressure Injection System.
Component Cooler Tubing Examination	Loss of material due to general and pitting corrosion of the brass tubes exposed to raw water has been identified as an applicable aging effect for the component cooler tubing in the Component Cooling System.
Condensate Cooler Tubing Examination	Loss of material due to pitting corrosion of the stainless steel tubes exposed to raw water has been identified as an applicable aging effect for the condensate coolers in the Condensate System.
Condenser Circulating Water System Internal Coatings Inspection	Condenser Circulating Water System Internal Coatings - Loss of material due to general and localized corrosion has been identified as applicable aging effect for the underground Condenser Circulating Water System piping.
Decay Heat Cooler Tubing Examination	Loss of material due to pitting corrosion and microbiologically influenced corrosion of the stainless steel tubes exposed to raw water has been identified as an applicable aging effect for the decay heat coolers in the Low Pressure Injection System.
Main Condenser Tubing Examination	Loss of material due to pitting corrosion and microbiologically influenced corrosion of the stainless steel tubes exposed to raw water has been identified as an applicable aging effect for the main condenser in the Condensate System.
Reactor Building Cooling Unit Tubing Inspection	Loss of material due to general and localized corrosion of the tube side exposed to raw water and localized corrosion due to galvanic corrosion and boric acid wastage of the copper alloy tubing has been identified as applicable aging effects for the cooling units in the Reactor Building Cooling System.
Standby Shutdown Facility Diesel Fuel Oil Tank Inspection	Loss of material due to general and localized corrosion of the carbon steel Standby Shutdown Facility Fuel Oil Tank has been identified as applicable aging effects for the external surfaces.
Turbine Generator Cooling Water System Strainer Inspection	Loss of material due to general and localized corrosion has been identified as an applicable aging effect for the carbon steel strainers in the Turbine Generator Cooling Water System.

4.3.9 REACTOR BUILDING SPRAY SYSTEM INSPECTION

Section 2.5 of OLRP-1001 identifies the stainless steel pipe in the Reactor Building Spray System that is subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to pitting corrosion and cracking due to stress corrosion as applicable aging effects. The *Reactor Building Spray System Inspection* will inspect specific stainless steel piping locations in the license renewal portions of the Reactor Building Spray System. The *Reactor Building Spray System Inspection* will have the following attributes.

Purpose - The purpose of *Reactor Building Spray System Inspection* will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components within the Reactor Building Spray System periodically exposed to an borated water environment that is not monitored.

Scope - The results of this inspection will be applicable to stainless steel piping and components downstream of the containment isolation valves BS-1 and BS-2 toward their respective spray headers, a total of two lines per Oconee unit. Because the piping is open to the Reactor Building environment, unmonitored conditions exist in any borated water which may be entrapped downstream of these valves.

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping due to the periodic presence of borated water in the Reactor Building Spray piping open to the Reactor Building environment. The inspection will assess the likelihood of the impact of these aging effects on the component intended function.

Method - An inspection of a select set of stainless steel piping locations will determine whether loss of material due to pitting corrosion and cracking due to stress corrosion have been occurring and whether further programmatic aging management will be required to manage these effects for license renewal. The length of susceptible piping will be determined. A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone, if available, since this is a more likely location for stress corrosion cracking to occur.

Sample Size - The inspection will include one of the six susceptible locations. The inspection locations are the piping between valves BS-1 and BS-2 and the normally open drain valves BS-15 and BS-20. If no parameters are known that would distinguish the susceptible locations, one location of the six available locations will be examined.

Industry Code or Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Frequency - The *Reactor Building Spray System Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable indication of loss of material due to pitting corrosion or cracking or cracking due to stress corrosion will require that an engineering analysis be performed to determine proper corrective action.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Reactor Building Spray System Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This one-time inspection activity has no current regulatory basis.

4.3.10 Reactor Coolant Pump Motor Oil Collection System Inspection

Section 2.5 of OLRP-1001 identifies the carbon steel, copper alloy, and stainless steel components in the Reactor Coolant Pump Motor Oil Collection System that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to general and galvanic corrosion for the carbon steel component materials and pitting and crevice corrosion for the carbon steel, copper alloys and stainless steel component materials in the Reactor Coolant Pump Motor Oil Collection System due to general and localized corrosion as an applicable aging effect. The *Reactor Coolant Pump Motor Oil Collection System Inspection* will have the following attributes.

Purpose - The purpose of the *Reactor Coolant Pump Motor Oil Collection System Inspection* will be to characterize the loss of material due to general and localized corrosion of the carbon steel, copper alloy and stainless steel components in the Reactor Coolant Pump Motor Oil Collection System that may periodically be exposed to water.

Scope - The results of this inspection will be applicable to the components in the system, particularly the lower portions of the system, with the potential to be exposed to water. Each Oconee unit has four Reactor Coolant Pump Oil Collection Tanks for a total population of twelve at Oconee.

Aging Effects - The inspection will determine the existence of loss of material due to general and galvanic corrosion for the carbon steel component materials and pitting and crevice corrosion for the carbon steel, copper alloys and stainless steel component materials as a result of periodic exposure to water.

Method - An inspection of several of the Reactor Coolant Pump Motor Oil Collection System Tanks will determine whether loss of material due to general and localized corrosion will be an aging effect of concern for the period of extended operation. The evidence gained from the tank examinations will be indicative of the condition of all materials in the lower portion of the system.

A visual examination on the bottom half of the interior surface of the tank will be performed to determine the presence of corrosion. The visual examination will also serve to characterize any instances of corrosion, both general and localized. A volumetric examination will then be conducted on any problematic areas to determine the condition of the lower portions of the tank which is a leading indicator of the other susceptible components.

Sample Size - The inspection will include one of the twelve Reactor Coolant Pump Motor Oil Collection System Tanks.

Industry Code or Standards - No code or standard exists to guide or govern this inspection.

Frequency - The *Reactor Coolant Pump Motor Oil Collection System Inspection* is a one-time inspection.

Acceptance Criteria - No unacceptable indication of loss of material due to various forms of corrosion as determined by engineering analysis. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Corrective Action - Any unacceptable indication of loss of material due to various forms of corrosion will require that an engineering analysis be performed to determine proper corrective action.

Timing of New Program or Activity - Following issuance of renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1).

Administrative Controls - The *Reactor Coolant Pump Motor Oil Collection System Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This one-time inspection activity has no current regulatory basis.

4.3.11 Reactor Vessel Internals Aging Management Program

As discussed previously in Section 2.4 of OLRP-1001, Duke has been actively participating in a B&W Owners Group (B&WOG) effort which has developed a series of topical reports whose purpose was to demonstrate that the aging effects for various Reactor Coolant System components are adequately managed for the period of extended operation for license renewal. One of these topical reports, BAW-2248, addresses managing the effects of aging of the reactor vessel internals [Reference 4.3-3]. As of June 1998, staff review of this report is still in progress.

Since the submittal of BAW-2248 in July 1997, the B&WOG has met with the NRC three times to discuss reactor vessel internals aging management issues [References 4.3-4, 4.3-5, and 4.3-6]. In addition, the NRC has recently issued Information Notice 98-11 [Reference 4.3-7] regarding cracking of reactor vessel internals baffle bolting.

To this end, Duke proposes an Oconee *Reactor Vessel Internals Aging Management Program* which may include the following activities:

(a) Continue the characterization of the potential aging effects that have been identified in BAW-2248, *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals* [Reference 4.3- 3]. The scope of the characterization includes, but is not limited to, the development of key program elements to address the following aging effects: cracking, reduction of fracture toughness, and loss of closure integrity.

(b) After the characterization of aging effects and prior to midnight February 6, 2013, Duke will develop an appropriate monitoring and inspection program, with attributes as defined in Section 4.2. This monitoring and inspection program will provide additional assurance that the reactor vessel internals will remain functional through the period of extended operation.

4.3.12 Small Bore Piping Inspection

Section 2.4 of OLRP-1001 identifies Reactor Coolant System small bore piping as subject to aging management review. Section 3.4 of OLRP-1001 and BAW-2243A identify cracking as an applicable aging effect for small bore piping. Alloy 600 small bore nozzles, which were also discussed in the BAW-2243A commitments, are addressed by the Oconee *Alloy 600 Program* (see Section 4.3.1 of OLRP-1001). The *Small Bore Piping Inspection* will manage the applicable aging effects for the period of extended operation. The *Small Bore Piping Inspection* will have the following attributes.

Purpose - The purpose of the *Small Bore Piping Inspection* will be to validate that service-induced weld cracking is not occurring in the small bore Reactor Coolant System piping that does not receive a volumetric examination under ASME Section XI.

Scope - The scope of *Small Bore Piping Inspection* includes the Oconee ISI [Footnote 5] Class A piping welds in lines less than 4 inch NPS [Footnote 6] including pipe, fittings, and branch connections.

Aging Effects - The aging effect being investigated is cracking of piping welds which may not be fully managed by the current ASME Section XI examinations. For Duke, these inspections are driven by the consequences of small bore piping failures rather than a lack of confidence in the current inservice inspection techniques to manage aging. In many instances, small bore piping cannot be isolated from the Reactor Coolant System and a leak could lead to a SBLOCA [Footnote 7] and plant shutdown.

Method - Selected inspection locations will receive either a destructive or non-destructive examination that permits inspection of the inside surface of the piping.

Sample Size - Pipe, fittings, and branch connections over the entire small bore size range will be considered for inspection. The total population of welds will be determined by summing the number of welds found in scope. To determine the inspection locations from this total population of welds, risk-informed approaches will be used to identify locations most susceptible to cracking. Susceptibility will be determined either qualitatively (i.e., based on site and industry experience, evaluation of current ASME Section XI inspection requirements and results, and any applicable regulatory initiatives) or quantitatively, or both. 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

5. ISI = Inservice Inspection
6. NPS = Nominal Pipe Size
7. SBLOCA = Small Break Loss of Coolant Accident

susceptibility and consequences, a list of potential inspection locations will be developed. Actual inspection locations will be selected based on physical accessibility, exposure levels, and the likelihood of meaningful results if a non-destructive technique is employed.

Industry Code or Standards - No code or standard exists to guide or govern this inspection. ASME Section XI provides rules for this piping, but not for volumetric or destructive examination. If destructive examination is employed, the Section XI rules for Repair and Replacement will be used to return piping to its original condition.

Frequency - The *Small Bore Piping Inspection* is a one-time inspection.

Acceptance Criteria or Standard - No unacceptable indication of cracking of piping welds as determined by engineering analysis.

Corrective Action - Any unacceptable indication of cracking of piping welds requires an engineering analysis be performed to determine proper corrective action.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Following issuance of a renewed operating licenses for Oconee Nuclear Station, this inspection will be completed by February 6, 2103 (the end of the initial license term for Oconee Unit 1).

Administrative Controls - The *Small Bore Piping Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - Renewal Applicant Action Item in the NRC SER concerning the "Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping," BAW-2243A:

"… The BWOG defers the development of details of … (2) the sample inspection of small bore RCS piping, to the renewal applicant referencing this topical report. The renewal applicant will have to provide details of these … inspection programs in its renewal application for staff review and approval."

4.3.13 Treated Water Systems Stainless Steel Inspection

Section 2.5 of OLRP-1001 identifies the stainless steel mechanical components in the Chemical Addition, Component Cooling, Demineralized Water, Filtered Water, Liquid Waste Disposal, SSF Drinking Water, and SSF Sanitary Lift Systems that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material and cracking as the applicable aging effects for the stainless steel components in these systems. These Oconee and Standby Shutdown Facility treated water systems contain stainless steel components which are exposed to treated or potable water falling under separate guidelines from the *Chemistry Control Program*(see Section 4.6) or under the provisions of the state of South Carolina. The Filtered Water System components are exposed to filtered water developed by the Oconee water treatment process.

The Chemical Addition, Component Cooling, Demineralized Water, and Liquid Waste Disposal System components are exposed to demineralized water developed by an additional step in the Oconee water treatment process. This demineralized water is the starting source for all primary and secondary water systems which are controlled by the *Chemistry Control Program* and has historically been of excellent quality.

The SSF Drinking Water and Sanitary Lift System component are exposed to potable water from the City of Seneca, South Carolina. The city drinking water standards are established by the state of South Carolina.

For all three groups of components, loss of material due to pitting corrosion and cracking due to stress corrosion have been identified as applicable aging effects requiring management for license renewal. Although the quality of the water in these cases is believed to be excellent, an inspection of a select set of stainless steel piping locations will determine whether loss of material due to pitting corrosion and cracking due to stress corrosion cracking has been occurring and whether further programmatic aging management will be required to manage these effects for license renewal. At the time of Application, no evidence exists that these aging effects are applicable to these systems and no industry experience has identified problems with stainless steel components in these type of systems.

Purpose - The purpose of the *Treated Water Systems Stainless Steel Inspection* will be to characterize the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components that could be occurring within several Oconee treated water systems.

Scope - The results of this inspection will be applicable to the stainless steel piping and valves in portions of several Oconee treated water systems which are exposed to treated or potable water falling under separate guidelines from the *Chemistry Control Program* and the state of South Carolina. The stainless steel components may experience aging that is not monitored by current plant programs. The focus on this inspection will be on a representative sample from each of the three treated water groups. The results of the inspections in each group will be an indicator of 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 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)

Aging Effects - The inspection will determine the existence of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel piping and valves.

Method- A volumetric examination of a length of the susceptible piping locations will be conducted for this inspection. This examination will include a stainless steel weld and heat affected zone since this is a more likely location for stress corrosion cracking to occur. In addition to the volumetric examination, a visual examination of the interior of a valve will be conducted to determine the presence of pitting corrosion.

Sample Size- Portions of stainless steel piping and valves, as applicable, for each of the three groups of system components will be inspected.

If in the Filtered Water System no parameters exist that would distinguish among the three Containment penetrations, one of the three Containment penetrations will be inspected. A stainless steel weld at one Containment isolation valve along with piping and weld between the isolation valve and the Containment penetration schedule transition point will be volumetrically examined in the 6-inches nominal pipe size stainless steel piping. In addition, one valve will be disassembled for an internal visual examination.

If in the Demineralized Water System no parameters exist that would distinguish among the four Containment penetrations, one of the three, 4-inches nominal pipe size, Containment penetrations will be inspected. A stainless steel weld at one Containment isolation valve along with piping and 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 one-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 in the license renewal portion of this system for an internal visual inspection.

Industry Code and Standards - No code or standard exists to guide or govern this inspection. Component wall thickness acceptability will be judged in accordance with the Oconee component design code of record.

Frequency - The *Treated Water Systems Stainless Steel Inspection* is a one-time inspection.

Acceptance Criteria or Standards - No unacceptable indication of loss of material due to pitting corrosion or cracking due to stress corrosion as determined by engineering analysis.

Corrective Action - Any unacceptable loss of material due to of pitting corrosion or stress corrosion cracking requires an engineering analysis be performed to determine potential impact on component intended function.

Specific corrective actions will be implemented in accordance with the Duke Quality Assurance Program.

Timing of New Program or Activity - Following issuance of renewed operating license for Oconee Nuclear Station, this inspection will be completed by February 6, 2013(the end of the initial license term for Oconee Unit 1).

Administrative Controls - The *Treated Water Systems Stainless Steel Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - This one-time inspection activity has no current regulatory basis

4.3.14 References for Section 4.3

4.3-1. BAW-2243A, *Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping,* The B&W Owners Group Generic License Renewal Program, June 1996.

4.3-2. BAW-2244A, *Demonstration of the Management of Aging Effects for the Pressurizer*, The B&W Owners Group Generic License Renewal Program, December 1997.

4.3-3. BAW-2248, *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals*, The B&W Owners Group Generic License Renewal Program, July 1997.

4.3-4. NRC Meeting Summary dated February 13, 1997, *Summary of Meeting on February 12, 1997 Between the U.S. Nuclear Regulatory Commission and B&WOG Representatives to Discuss the Status of the B&WOG Generic License Renewal Program,* Project No. 683.

4.3-5. NRC Meeting Summary dated September 16, 1997, *Summary of Meeting on August 28, 1997 Between the U.S. Nuclear Regulatory Commission and B&WOG Representatives to Discuss the Status of the B&WOG Generic License Renewal Program,* Project No. 683.

4.3-6. NRC Meeting Summary dated May 6, 1998, *Summary of Meeting on April 23, 1998 Between the U.S. Nuclear Regulatory Commission and B&WOG Representatives to Discuss the Status of the B&WOG Generic License Renewal Program,* Project No. 683.

4.3-7. NRC Information Notice 98-11: Cracking of Reactor Vessel Internal Baffle Former Bolts in Foreign Plants, March 25, 1998.

4.4 BATTERY RACK INSPECTIONS

Section 2.7.2.2 of OLRP-1001 identifies battery racks as subject to aging management review. Section 3.7.2.2 of OLRP-1001 identifies loss of material due to corrosion as an applicable aging effect. *Battery Rack Inspections*, which are conducted in accordance with requirements contained in the Oconee Improved Technical Specifications, will manage the applicable aging effects for the period of extended operation. *Battery Rack Inspections* have the following attributes. In addition, because *Battery Rack Inspections* are part of an existing program, operating experience and demonstration are provided, as applicable.

4.4.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Battery Rack Inspections* is to ensure the structural integrity of the battery racks. *Battery Rack Inspections* constitute a subset of the many activities performed under the auspices of the Battery Inspections required by Oconee Improved Technical Specifications SR 3.8.1.13, *AC Sources Operating*, SR 3.8.3.2, *DC Sources Operating,* and SR 3.10.1.10, *Standby Shutdown Facility*, [Reference 4.4-1].

Scope - The scope of the *Battery Rack Inspections* include the racks for the following batteries:

- 125 VDC Instrumentation and Control Batteries at Keowee
- 125 VDC 230 kV Switchyard Batteries
- 125 VDC Instrument and Control Batteries in the Auxiliary Buildings
- 125 VDC Instrument and Control Batteries in the Standby Shutdown Facility

Aging Effects - Battery racks are inspected for physical damage or abnormal deterioration, including loss of material due to corrosion.

Method - A visual inspection will be performed as require by Oconee Improved Technical Specifications.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - NUREG-1430, *Standard Technical Specifications - Babcock and Wilcox Plants*, Revision 1, April 1995; IEEE 450, *IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations* [Reference 4.4-2].

Frequency - The inspection is performed annually as required by the Oconee Improved Technical Specifications. This surveillance frequency is consistent with the recommendation to check the structural integrity of the battery rack on a yearly basis as provided in IEEE-450 [Reference 4.4-2, Section 4.3.3].

Acceptance Criteria - No visual indication of loss of material due to corrosion. The presence of physical damage or deterioration does not necessarily represent a failure, provided an evaluation determines that the physical damage or deterioration does not affect the ability of the battery to perform its function.

Corrective Action - Areas which do not meet the acceptance standards are accepted by engineering evaluation or corrected by repair or replacement activities.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - *Battery Rack Inspections* are implemented by written procedures as required by Oconee Improved Technical Specifications 5.4, *Administrative Controls, Procedures* and in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Oconee Improved Technical Specifications SR 3.8.1.13, *AC Sources Operating*, SR 3.8.3.2, *DC Sources Operating*, and SR 3.10.1.10, *Standby Shutdown Facility*.

4.4.2 Operating Experience And Demonstration

A review of Oconee-specific operating experience did not identify any instances of loss of material of any battery racks. Based on the review of Oconee operating experience, the continued implementation of the *Battery Rack Inspections* provides reasonable assurance that the aging effects will be managed such that the battery racks will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.4.3 References for Section 4.4

4.4-1. *Oconee Nuclear Station, Improved Technical Specifications*

4.4-2. IEEE -450, *IEEE Recommended Practice for Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Generating Stations and Substations*, Institute of Electrical and Electronics Engineers, 345 East 47th Street, New York, NY.

4.5 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

Sections 2.4, 2.5, and 2.7 of OLRP-1001 identify carbon steel components that are subject to aging management review. Sections 3.4, 3.5 and 3.7 identify loss of material due to boric acid corrosion of carbon steel and low alloy steel components as an applicable aging effect. The *Boric Acid Wastage Surveillance Program* has the following attributes. In addition, because the *Boric Acid Wastage Surveillance Program* is an existing program, operating experience and demonstration are provided, as applicable.

4.5.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Boric Acid Wastage Surveillance Program* is to provide reasonable assurance that leaks of boric acid are promptly identified and corrected and that loss of material due to boric acid corrosion is evaluated. This program focuses on small leaks which generally occur below technical specification limits for operational leakage.

Scope - The results of the program are applicable to mechanical components and structural components fabricated from carbon steel and low alloy steel that are located in proximity to borated systems. This program addresses equipment both inside and outside the Reactor Building. Bolted closures such as manways and flanged connections of systems containing dissolved boric acid are also included.

Aging Effects - The aging effect is loss of material due to boric acid corrosion of the carbon steel and low alloy steel.

Method - Visual inspections are performed on external surfaces in accordance with plant procedures.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - ASME Section XI and Generic Letter 88-05 [Reference 4.5-1].

Frequency - Inspections are performed each time the Reactor Building is entered (not to exceed intervals associated with refueling outages and ISI inspections).

Acceptance Criteria or Standard - The *Boric Acid Wastage Surveillance Program* includes the following acceptance criteria:

(1) Free from leakage from non-insulated components

(2) Free from leakage in excess of permissible levels defined by the owner on devices with leak limiting devices
(3) Free from leakage from insulated or inaccessible components
(4) Free from areas of general corrosion of a component resulting from leakage
(5) Free from discoloration or accumulated residues on surfaces or components, insulation, or floor areas that may indicate borated water leakage.

Corrective Action - When the programmatic activities described as the *Boric Acid Wastage Surveillance Program* lead to detection of an unacceptable condition, the following corrective actions are required:

(1) Locate leak source and areas of general corrosion.
(2) Evaluate pressure-retaining components suffering more than 10% wall loss for continued service or replacement.
(3) Evaluate other affected components such as supports and other structural members for continued service, repair or replacement.

Items which do not meet the acceptance criteria will be repaired or replaced in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - Implemented through Nuclear Generation Department administrative and workplace procedures.

Regulatory Basis - ASME Section XI, Examination Category B-P, *All Pressure Retaining Components,* Examination Category C-H, *All Pressure Retaining Components*; Examination Category D-A, *Systems in Support of Reactor Shutdown Function;* Examination Category D-B, *Systems in Support of Emergency Core Cooling, Containment Heat Removal*, *Atmospheric Cleanup, and Reactor Residual Heat Removal* and Examination Category D-C, *Systems in Support of Residual Heat Removal from Spent Fuel Storage Pool*; Duke commitments in response to NRC Generic Letter 88-05 [Reference 4.5-2].

4.5.2 Operating Experience and Demonstration

Plant problem identification reports describe activities such as diagnosis of the source of leakage, plant engineering assessment of potential corrosion damage, and initiation of work requests to correct any equipment deficiencies. Engineering reports describe multiple trips of engineering personnel into containment during each outage to evaluate boric acid deposits and potential corrosion damage of the surrounding carbon steel structures. Selected reports also describe follow-up evaluations of damage discovered during inspections in previous outages. The fact that no structural damage of carbon steel and low alloy steel components has occurred as the result of loss of material due to boric acid corrosion demonstrates the effectiveness of the *Boric Acid Wastage Surveillance Program* at Oconee.

Based on the above review, the continued implementation of the *Boric Acid Wastage Surveillance Program* provides reasonable assurance that the aging effects will be managed such that the carbon steel and low alloy steel components in proximity to borated systems will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.5.3 References for Section 4.5

4.5-1. Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, dated March 17, 1988.

4.5-2. H. B. Tucker (Duke) letter dated August 1, 1988 to Document Control Desk (NRC), *Response to Generic Letter 88-05, Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants,* Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

4.6 CHEMISTRY CONTROL PROGRAM

4.6.1 BACKGROUND

The primary objective of the Oconee *Chemistry Control Program* is to protect the integrity, reliability, and availability of plant equipment and components by minimizing corrosion in fluid systems. Other objectives include maximizing thermal performance by minimizing deposition and fouling on heat transfer surfaces, reducing radiation exposure by the control of activated corrosion products, protecting fission product barrier by prevention of fuel cladding defects, and assisting in reactivity control through reactor coolant boron management. These objectives are accomplished by maintaining acceptably low levels of impurities in fluid systems and by controlling the environment of certain fluid systems through the use of chemical additives. In establishing chemistry limits and specifications to control the concentration of chemical impurities and chemical additives, system metallurgy and operating conditions must be considered to ensure development of an effective chemical control program. The Oconee *Chemistry Control Program* is maintained through the development of and adherence to implementing procedures which define chemistry specifications and limits, sampling and analysis frequencies, and corrective actions to be taken if specified limits are exceeded.

Since initial operation, and continuing through present day operation, Oconee has maintained a well-defined *Chemistry Control Program* for most fluid systems (e.g., the chemistry of service water systems is not controlled). During the early years of operation, the Oconee *Chemistry Control Program* for these fluid systems was based on vendor specifications or recommendations. For primary and secondary systems, the *Chemistry Control Program* was based on specifications by the Babcock & Wilcox Co., the manufacturer of the nuclear steam supply system for the Oconee units [Reference 4.6-1]. For other systems, the Oconee *Chemistry Control Program* was based on applicable vendor recommendations for those systems. For chemically-treated auxiliary systems, such as closed loop cooling water systems, the chemistry control program was developed based on recommendations of the water treatment vendor who supplied the specific chemical additives for the systems, relying on its expertise in the fields of water treatment and corrosion control in establishing chemistry operating specifications.

In the 1980s, the Electric Power Research Institute (EPRI) led the development of industry-wide guidelines for establishing and maintaining chemistry control programs for certain nuclear plant fluid systems. This effort led to the publication of the EPRI PWR Primary Water Chemistry Guidelines [Reference 4.6-2] and the EPRI PWR Secondary Water Chemistry Guidelines [Reference 4.6-3]. These documents were developed with technical input and concurrence from the three U.S. nuclear steam supply system vendors, as well as utility and water treatment experts who also participated in the development effort.

These guidelines, and their subsequent revisions, have been based on well-established corrosion control philosophy and practices, taking into account industry experience in water chemistry control. Duke personnel were involved in the initial development of each of these documents, as well as subsequent revisions. After the initial publication of these EPRI guideline documents, the Oconee *Chemistry Control Program* was revised to incorporate EPRI recommendations. Similarly, with only minor exceptions as justified, the Oconee *Chemistry Control Program* has been revised to incorporate recommendations in each of the subsequent revisions of the EPRI guideline documents. In general, the EPRI guideline documents have superseded the original nuclear steam supply system vendor recommendations as the basis for the primary and secondary system chemistry control programs at Oconee.

For other fluid systems not addressed by EPRI guideline documents, the chemistry control program has continued to be maintained based on vendor recommendations, and revised as appropriate based on Duke or external industry operating experience. As new industry recommendations are established which reflect best available practice (i.e., EPRI, INPO, or other), these recommendations are incorporated, as appropriate, into the Oconee *Chemistry Control Program.*

A key aspect of the Oconee *Chemistry Control Program* is the sampling and analysis of fluid systems to determine the concentration of chemical impurities and chemical additives. Fluid systems at Oconee are sampled and analyzed by procedures, which are controlled by the *Duke Quality Assurance Program* (see Section 4.13). Parameters monitored, frequency of sampling, acceptance criteria (i.e., specifications), and corrective actions for out-of-specification results are similarly addressed by procedures. Furthermore, chemical analyses are governed by a quality control program to ensure accurate results. Over the years, the analytical techniques, sampling systems, and chemistry laboratories have been upgraded to reflect ongoing technological developments. Chemistry data for monitored parameters are routinely trended to identify subtle trends which may be indicative of an underlying operational problem. In many cases, trending allows correction prior to the parameter becoming out-of-specification.

The overall effectiveness of the chemistry program is supported by the excellent operating experience for systems, structures, and components which are influenced by the chemistry control program. With the exception of the steam generators (discussed under *Secondary Chemistry Control Specifications*), no chemistry related degradation has resulted in loss of component intended functions on any systems for which the fluid chemistry is actively controlled.

The following sections provide additional descriptions and demonstrations of the:
(1) *Primary Chemistry Control Specifications,*
(2) *Secondary Chemistry Control Specifications*,
(3) *Component Cooling System Chemistry Control Specifications,*
(4) *Standby Shutdown Facility Fuel Oil Surveillances.*

4.6.2 Primary Chemistry Control Specifications

Sections 2.4, 2.5, and 2.7 of OLRP-1001 identify components subject to aging management review that are exposed to water controlled by the Oconee *Primary Chemistry Control Specifications*. Sections 3.4, 3.5, and 3.7 identify loss of material and cracking as applicable aging effects for these components. The Oconee *Primary Chemistry Control Specifications* will manage these applicable aging effects for the period of extended operation.

Oconee maintains primary chemistry in accordance with recommendations in the current revision of the EPRI PWR Primary Water Chemistry Guidelines. The Oconee *Primary Chemistry Control Specifications* have been based on the recommendations in this EPRI guideline document since it was initially published in 1986. Prior to that time, the Oconee *Primary Chemistry Control Specification* was based on recommendations by Babcock & Wilcox Co., the Oconee nuclear supply system vendor. The Oconee *Primary Chemistry Control Specifications* apply to the following systems, structures, and components within the scope of license renewal:

System, Structure, or Component Sampled	**System, Structure, or Component Directly or Indirectly Monitored**
Reactor Coolant System	Reactor Coolant System Low Pressure Injection System (when RCS < 200 ^{o}F) High Pressure Injection System Coolant Storage System Chemical Addition System
Pressurizer	Reactor Coolant System Chemical Addition System
Core Flood Tanks	Core Flood System
Borated Water Storage Tank	Low Pressure Injection System (certain times) Reactor Building Spray System Core Flood System
Spent Fuel Pool	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

The Oconee *Primary Chemistry Control Specifications* contains chemical parameter specifications, sampling and analysis frequencies, and corrective actions for primary chemistry control. The monitored parameters and acceptance criteria were established in accordance with the EPRI guidelines or Oconee Technical Specifications, where applicable. The frequency of sampling is either daily, weekly, monthly, quarterly or as required, based on plant operating conditions. The frequency has been established based on Technical Specification requirements, EPRI guidelines, or Oconee-specific experience. Oconee-specific operating experience confirms the acceptability of these specifications.

Corrective actions for each monitored primary chemistry parameter have been established. Corrective actions to address out-of-specification conditions range from simple manipulations to bring the parameter back in specification within a specified time frame, to unit shutdown in more extreme cases. The specific corrective action depends on the parameter that is out-of-specification and the degree to which it is out-of-specification. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions (i.e., that chemistry concentrations are back to normal values).

The chemistry control specifications for the Oconee Reactor Coolant System were devised to create a chemical environment in the Reactor Coolant System that will minimize corrosion of system components. Wetted surfaces in the system are primarily constructed of stainless steel and Alloy 600 materials. Makeup water to the system is demineralized water. A dissolved hydrogen residual is maintained in the reactor coolant to maintain a reducing environment and to react with radiolytically produced oxygen. Lithium hydroxide is added to the system in coordination with boron concentration to maintain moderately alkaline conditions. Maximum levels for chloride, fluoride, and oxygen are specified to prevent stress corrosion cracking and loss of material due to pitting corrosion of stainless steel materials. Maximum levels for sulfate are specified to prevent intergranular corrosion and pitting of Alloy 600 materials. Prior to the development of sulfate analysis (mid-1980s), acceptably low sulfate levels were demonstrated by monitoring of specific conductivity.

The water in the letdown piping and letdown storage tank is from the Reactor Coolant System, and is expected to be similar in chemical impurity concentrations as reactor coolant. Reactor coolant letdown is processed through a mixed bed demineralizer, so impurity concentrations may be slightly lower downstream of the demineralizer. Also, hydrogen overpressure is maintained in the letdown storage tank gas space and serves as the point of hydrogen addition to the system, so dissolved hydrogen concentrations in the letdown storage tank may be slightly greater than the Reactor Coolant System as a whole.

The water in the pressurizer is sampled and analyzed in addition to the samples taken directly from the Reactor Coolant System. The pressurizer is sampled for chloride and oxygen at a frequency ranging from daily to "as required," depending on operating conditions. The specifications for chloride and oxygen are the same as for the Reactor Coolant System. The pressurizer is not sampled for fluoride or sulfate, but concentrations should be similar to that in the Reactor Coolant System.

Reactor coolant sample lines containing reactor coolant water have the same chemical composition as the water in the Reactor Coolant System. This includes the hot leg sample line, letdown system sample line, post-accident sample line, and pressurizer sample line.

The High Pressure Injection System and the Low Pressure Injection System are not directly sampled and monitored. Whenever these systems are in service, they contain reactor coolant water and have the same chemical composition as water in the Reactor Coolant System at the given operating condition.

The Core Flood System is directly sampled for boron. However, the borated water storage tank, which serves as makeup for the core flood tanks, is sampled for additional parameters. Chloride and fluoride concentrations are monitored and limited, thus providing adequate controls for the core flood tanks, while sulfate is monitored as a diagnostic parameter. The borated water storage tank also serves as the supply for the Reactor Building Spray system. Thus, this system is controlled so as to have the same chemistry as the water in the borated water storage tanks.

The Spent Fuel Pool is sampled for chloride and sulfate, but not fluoride. Chloride is monitored and controlled, while sulfate is monitored as a diagnostic parameter. Conductivity is monitored and controlled in the Spent Fuel Pool, thus offering a surrogate means of controlling sulfate and fluoride. 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 indirectly controlled. These include the Spent Fuel Pool Cooling System, the Spent Fuel Pool Liner, the Spent Fuel Storage Racks, Fuel Transfer Canal Liner Plate, Structural Steel and Plates in the Spent Fuel Pool, and the SSF Reactor Coolant Makeup System.

The overall effectiveness of the Oconee *Primary Chemistry Control Specifications* 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 component intended function on any primary side systems or components for which the fluid chemistry is controlled.

Based on the above review, the continued implementation of the *Primary Chemistry Control Specifications* provides reasonable assurance that the cracking and loss of material will be managed such that the structures and components exposed to water controlled by the *Primary Chemistry Control Specifications* will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.3 Secondary Chemistry Control Specifications

Sections 2.4 and 2.4 of OLRP-1001 identify components subject to aging management review that are exposed to water controlled by the *Secondary Chemistry Control Specifications.* Sections 3.4 and 3.5 of OLRP-1001 identify cracking and loss of material as applicable aging effects for these components. The *Secondary Chemistry Control Specifications* will manage these applicable aging effects for the period of extended operation.

Oconee maintains secondary chemistry in accordance with recommendations in the current revision of the EPRI PWR Secondary Water Chemistry Guidelines. The Oconee *Secondary Chemistry Control Specifications* have been based on the recommendations in this EPRI guideline document since it was initially published in 1981. Prior to that time, the *Secondary Chemistry Control Specifications* were based on recommendations by Babcock & Wilcox Co., the Oconee nuclear supply system vendor. The Oconee *Secondary Chemistry Control Specifications* apply to the following structures, systems and components within the scope of license renewal:

System, Structure, or Component Sampled	System, Structure, or Component Directly or Indirectly Monitored
Hotwell	Condensate System Emergency Feedwater System
Feedwater System - Final chemistry before use in steam generators	Chemical Addition System Feedwater System Steam Generators Main Steam System

The Oconee *Secondary Chemistry Control Specifications* contain chemical parameter specifications, sampling and analysis frequencies, and corrective actions for secondary chemistry control. The monitored parameters include, but are not limited to, dissolved oxygen, sodium, chloride, sulfate, and silica. The monitored parameters and acceptance criteria were established in accordance with the EPRI guidelines. The frequency of sampling is either continuous, daily, weekly, or as required based on plant operating conditions. The frequency has been established based on the EPRI guidelines, or based on Oconee-specific experience. Oconee-specific operating experience confirms the acceptability of these specifications.

Corrective actions for each monitored secondary chemistry parameter have been established. Corrective actions to address out-of-specification conditions range from simple manipulations to bring the parameter back in specification within a specified time frame to unit shutdown in more extreme cases. The specific corrective action depends on the parameter that is out-of-specification and the degree to which it is out-of-specification. Whenever corrective actions are taken to address an abnormal chemistry condition, increased sampling is utilized to verify the effectiveness of these actions (i.e., that chemistry concentrations are returned to within normal values).

The *Secondary Chemistry Control Specifications* were devised to create a chemical environment in the system that will minimize corrosion of secondary system components. Wetted surfaces in the system are primarily constructed of carbon steel and stainless steel materials. Makeup water to the system is demineralized water that is deaerated by spraying it into the upper surge tank dome under vacuum. Condenser vacuum helps maintain low oxygen conditions in the system. In addition, hydrazine is added to the system as an oxygen scavenger and to maintain a chemically-reducing environment. Hydrazine also thermally decomposes to produce ammonia , which helps maintain an alkaline pH in the system.

Organic amines of varying volatility have been added to the Oconee secondary system since 1989 in an effort to reduce flow-assisted corrosion of steam extraction piping and to reduce iron transport to the steam generators. This is accomplished by creating a more alkaline pH condition in the liquid (water) phase in two phase steam extraction piping than can be accomplished with ammonia alone. Morpholine was used for this purpose until 1994**,** and then was replaced with ethanolamine (ETA) due to the latter's more favorable volatility and base strength. Beginning in 1997, another organic amine, dimethylamine, was added in combination with ethanolamine to further reduce iron transport and deposition in the steam generators. While the current combination of ethanolamine, dimethylamine, and ammonia (from hydrazine decomposition) is believed to provide the best overall protection of carbon steel surfaces from corrosion, other pH control approaches may be used in the future if they are determined to be more beneficial than the current approach.

In addition to the chemical additives discussed above for oxygen scavenging and pH control, since initial operation Oconee has utilized a powdered resin condensate polisher system (Powdex) to assist with secondary system chemistry control. These condensate polishers utilize finely ground, powdered ion exchange resins in the form of a precoat on the polisher filter elements. The condensate polishers are effectively used for filtration of suspended solids, removal of ionic impurities, and protection against condenser inleakage.

Maximum levels for various impurities in the system have been established, including dissolved oxygen, sodium, chloride, and sulfate to prevent general or localized corrosion of various system components. Maximum levels for silica have been established to minimize deposition of silica compounds on turbine blades. Maximum levels for feedwater iron have been established to minimize deposition of iron deposits in the steam generators. Since the Oconee secondary system has no components constructed with copper alloys, maximum levels for copper have not been required.

The effectiveness of the *Secondary Chemistry Control Specifications* is demonstrated by the excellent operating experience for secondary systems, structures, and components which are influenced by the chemistry control program. With the exception of the steam generators, no chemistry-related degradation has resulted in loss of component intended functions on any systems for which fluid chemistry is controlled. With regard to the steam generators, a major study concluded that, while the degradation has a local environmental component, there is no direct correlation with a specific water chemistry condition, and that chemistry control "has been excellent and has consistently met or exceeded industry standards and guidelines" [Reference 4.6-4].

Based on the above review, the continued implementation of the *Secondary Chemistry Control Specifications* provides reasonable assurance that the aging effects will be managed such that the Condensate, Emergency Feedwater, Feedwater, and Main Steam System components, and the steam generators, will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.4 Component Coolant Chemistry Control Specifications

Section 2.5 of OLRP-1001 identifies components of the Component Cooling Water System subject to aging management review that are exposed to water controlled by the *Component Coolant Chemistry Control Specifications.* Section 3.5 of OLRP-1001 identifies cracking and loss of material as applicable aging effects for these components. The *Component Coolant Chemistry Control Specifications* will manage these aging effects for the period of extended operation.

The Component Cooling Water System is a closed loop cooling water system which provides chemically-treated, demineralized water to components that require a barrier between potentially radioactive water and the ultimate source of the cooling water (i.e., lake water). The materials of construction of the component cooling system primarily consist of carbon steel, stainless steel, and copper alloys. The water quality and treatment method used in the component cooling system are compatible with these metallurgies.

The water quality and treatment ensure very low general corrosion rates and protection against stress corrosion cracking and loss of material due to pitting corrosion. Oconee utilizes the chromate-phosphate treatment recommended by Babcock & Wilcox Co., the Oconee nuclear steam supply system vendor, as the basis for the chemistry control specifications for the Component Cooling System.

From initial plant operation until 1996, the chemistry control specifications for the Oconee Component Cooling System were based on recommendations contained in the Babcock & Wilcox chemistry specifications, BAW-1385. The parameters monitored included pH, chromate, phosphate, suspended solids, chloride, fluoride, and γ isotopic. Parameters were sampled either weekly or monthly.

From 1996 to present, the system has been treated with a modified, but still conservatively adequate program. Changes to the program include reducing the specified concentration of CrO_4; eliminating the fluoride sample based on historical data; decreasing the sample frequency from monthly to quarterly based on stable historical data trends; and substituting iron and copper sampling for suspended solids. The parameters currently being monitored include pH, chromate, phosphate, chloride, iron, copper, and γ isotopic. Parameters are sampled either weekly, monthly, or quarterly as required by the Oconee Chemistry Manual. Oconee operating experience has been incorporated in the new frequencies, parameters, and acceptance criteria of this sampling program.

Corrective actions for each monitored parameter have been established and are described in the applicable section of the Oconee Chemistry Manual. Correction actions are taken if routinely monitored parameters are found to be outside of specified control ranges. Specific corrective actions vary depending on which parameter(s) is (are) out of range, but may include adding additional chromate, bi-phosphate or tri-phosphate, or placing the system into feed and bleed to remove elevated concentrations of contaminants.

Iron and copper monitoring of the Oconee Component Cooling System confirms that the applied chemistry control program has resulted in extremely low corrosion rates of steel and copper alloyed metallurgies in the system.

Based on the above review, the continued implementation of the *Component Coolant Chemistry Control Specifications* for the Component Cooling System provides reasonable assurance that the aging effects will be managed such that the Component Cooling System components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.5 Standby Shutdown Facility Fuel Oil Surveillances

Section 2.5 of OLRP-1001 identifies the mechanical carbon steel and stainless components that are exposed to fuel oil controlled by the *Standby Shutdown Facility (SSF) Fuel Oil Surveillances* that are subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material for carbon steel and loss of material and cracking for stainless steel as applicable aging effects for these components when exposed to fuel oil contaminated with water or bacterial and fungal activity. The *SSF Fuel Oil Surveillances* will manage these applicable aging effects for the period of extended operation.

The intent of the Oconee *SSF Fuel Oil Surveillances* is to ensure that SSF fuel oil does not contain contaminants which will introduce conditions detrimental to the components in fuel oil systems. The surveillances place emphasis on the detection of water and bacterial/fungal activity in fuel oil with the purpose of minimizing the potential for loss of material in carbon steel and loss of material and cracking in stainless steel components. The following discussion describes Oconee SSF Fuel Oil Surveillances.

The SSF Diesel Generator Fuel Oil System is included within the scope of the Oconee *SSF Fuel Oil Surveillances*. All components which have been identified as being subject to an aging management review are exposed to fuel oil in this system. Therefore, the scope of the quarterly sampling and analysis performed by the Oconee *SSF Fuel Oil Surveillances* covers all subject components in the SSF fuel oil system. The quarterly frequency is considered to be reasonable based on industry operating experience [Reference 4.6-5, SR 3.10.1.8 Bases] as well as Oconee specific experience.

The *SSF Fuel Oil Surveillances* sample and analyze on-site fuel oil supplies for the presence of water and bacterial/fungal activity. The specific requirements of the surveillances include quarterly sampling and analysis of fuel oil supplies. The parameters monitored and acceptance criteria established are consistent with those provided in ASTM D975 [Reference 4.6-6].

The Oconee *SSF Fuel Oil Surveillances* are controlled by the Oconee *Chemistry Control Program* and implemented by Chemistry procedures which are controlled by the *Duke Quality Assurance Program* (see Section 4.13). The guidance stated in the Oconee *Chemistry Control Program* is governed by Oconee Improved Technical Specifications [Reference 4.6-7 ITS SR 3.10.1.8 and ITS 5.5.14] which require that the water content in fuel oil be verified on a quarterly basis. The Technical Specification require specific corrective actions to be taken if the water content acceptance limits are exceeded. The Oconee *Chemistry Control Program* requires that Operations staff be notified in the event that bacterial/fungal levels are out of specification whereupon corrective actions are taken.

Additionally, new fuel oil deliveries are treated with a biocide and sampled and analyzed for water content.

A review of available sample results for water contamination and bacterial/fungal activity in the SSF Diesel Generator Fuel Oil System indicate values well below acceptance criteria. Water content levels have been 0.00 % by volume. Bacterial/fungal activity shows scattered results with no recognizable trend. Responsible Chemistry personnel cannot recall any instances of exceeding the acceptance values for either water or bacterial/fungal activity since the SSF Fuel Oil System became operational in 1982.

Based on the above review, the continued implementation of the *SSF Fuel Oil Surveillances* provide reasonable assurance that the aging effects will be managed such that the SSF Diesel Generator Fuel Oil System components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.6.6 REFERENCES FOR SECTION 4.6

4.6-1 . BAW-1385, *Water Chemistry Manual for 177FA Plants*, Babcock & Wilcox.

4.6-2 . *EPRI PWR Primary Water Chemistry Guidelines,* Revision 3, EPRI Report TR-105714, November 1995.

4.6-3. *EPRI PWR Secondary Water Chemistry Guidelines,* Revision 4, EPRI Report TR-102135-R4, November 1996.

4.6-4. Dominion Engineering Report, DEI-485, Rev. 0, February, 1997.

4.6-5. NUREG-1430, “Standard Technical Specifications for Babcock and Wilcox Plants,” Revision 1, NRC, April 1995.

4.6-6. D975-94, “Standard Specification for Diesel Fuel Oils”, *Annual Book of ASTM Standards,* 1996.

4.6-7. *Oconee Nuclear Station, Improved Technical Specifications*

4.7 COATINGS PROGRAM

The Oconee *Coatings Program* was established prior to initial licensing of the station and has been in effect continuously since then. Over the years, enhancements and refinements have been made to improve program effectiveness. The purpose of the Oconee *Coatings Program* is to protect the underlying structure or component from detrimental effects of the environment to which it is exposed during normal operation and to reduce personnel exposure to as low as reasonably achievable in areas subject to radiation and contamination. Coatings applied inside primary containment must either remain intact during postulated design basis events or be documented as unqualified with no impact on the Reactor Building emergency sump. The elements of the Oconee *Coatings Program* are documented in a Nuclear Generation Department Directive.

An effective coatings program contains two principal activities. The first activity includes the proper selection of coating, the proper preparation of the surface, and the application of the coating and quality control measures during each phase of the coating process. Proper performance of these activities provides assurance that the coatings will function as intended in the service environment and not degrade abnormally over time. Coating degradation can occur in areas of excessive moisture, or in areas where conditions exist that exceed the design capability of the coating system. Coating applications are specified for each structure and component as required. Materials of construction of the structure or component, operating conditions of the component, and ambient environmental conditions are all considered when the type of coating application is specified.

The Oconee *Coatings Program* consists of four service levels based on the anticipated operating conditions. For each of these service levels, the Oconee *Coatings Program* contains guidance for:

(1) establishment of coating schedules,
(2) selection and procurement of coatings, and
(3) specification of surface preparation and coating application requirements including the establishment of appropriate inspection requirements and criteria.

Service Level I coatings apply to exposed surface areas within the Reactor Building (Containment), which are designed to withstand the postulated loss-of-coolant accident environment (LOCA). Service Level I coatings are specified in an Oconee coating schedule and apply to structures and components within the Reactor Building including but not limited to: the liner plate, structural steel and support steel, hangers, concrete equipment bases, insulated piping and insulated pipe hangers, electrical penetrations, polar crane, and carbon steel attachments to the liner plate. Cable tray and duct work are galvanized. No coatings are on stainless steel piping. Insulated carbon steel piping is covered with lagging. Original Service Level I coatings used at Oconee were determined to be acceptable based on proven industry operating experience and LOCA testing by the coating manufacturer. Service Level I coatings currently used for maintenance have been LOCA tested over the original coating in accordance with ANSI N101.2 and ANSI N101.4 [References 4.7-1 and 4.7-2, respectively]. Duke specifications, which are based on high quality 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], 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 contained in the Oconee UFSAR, Chapter 3, Table 3-12 [Reference 4.7-13].

The NRC has previously established that ANSI N101.2 and ANSI N101.4 are acceptable standards for governing activities related to the selection and evaluation of protective coatings applied in the shop or in the field [Reference 4.7-14]. Regulatory Guide 1.54 is currently undergoing a major revision and a generic letter is expected which concerns protective coating deficiencies in the containment [Reference 4.7-15].

In conclusion, the Oconee *Coatings Program* has been in effect at Oconee since prior to initial licensing. The program is based on well established, high quality industry standards and has been revised as necessary based on Oconee experience. The continued implementation of the Oconee *Coatings Program* provides reasonable assurance that the specified coatings will remain intact under design loading conditions such 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 for the period of extended operation.

4.7.1 References for Section 4.7

4.7-1. ANSI N101.2 (1972), *Protective Coatings(Paints) for Light Water Nuclear Reactor Containment Facilities.*

4.7-2. ANSI N101.4, *Quality Assurance for protective Coatings Applied to Nuclear Facilities.*

4.7-3. Steel Structures Painting Council (SSPC), SSPC-PA-1, *Shop, Field and Maintenance Painting.*

4.7-4. Steel Structures Painting Council (SSPC), SSPC-PA-2, *Measurement of Dry Paint Thickness with Magnetic Gages.*

4.7-5. Steel Structures Painting Council (SSPC), SSPC-1, *Solvent Cleaning.*

4.7-6. Steel Structures Painting Council (SSPC), SSPC-2, *Hand Tool Cleaning.*

4.7-7. Steel Structures Painting Council (SSPC), SSPC-3, *Power Tool Cleaning.*

4.7-8. Steel Structures Painting Council (SSPC), SSPC-5, *White Metal Blast Cleaning.*

4.7-9. Steel Structures Painting Council (SSPC), SSPC-6, *Commercial Blast Cleaning.*

4.7-10. Steel Structures Painting Council (SSPC), SSPC-7, *Brush Off Blast Cleaning.*

4.7-11. Steel Structures Painting Council (SSPC), SSPC-10, *Near White Metal Blast Cleaning.*

4.7-12. Steel Structures Painting Council (SSPC), SSPC-11, *Power Tool Cleaning to Bare Metal.*

4.7-13. *Oconee Nuclear Station, Updated Final Safety Analysis*, as revised.

4.7-14. Regulator Guide 1.54, *Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants*, June 1973.

4.7-15. 62 FR 26331, May 13, 1997, Proposed Generic Letter: *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 the Containment.*

4.8 CONTAINMENT INSERVICE INSPECTION PLAN

As background, the NRC amended 10 CFR §50.55a [Reference 4.7.1-1] to incorporate by reference the ASME Boiler and Pressure Vessel Code, Section XI Subsections IWE and IWL 1992 Edition with the 1992 Addenda, with specified modifications and limitations. The Oconee *Containment Inservice Inspection Plan* incorporating Subsection IWE and Subsection IWL examination requirements is currently under development to meet the expedited examination date of September 9, 2001.

Throughout the service life of nuclear power plants, components classified as either Class MC or Class CC pressure retaining components and their integral attachments must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of the ASME Code and Addenda. These requirements are incorporated by reference in §50.55a(b). They are subject to the limitation listed in subsection (b)(2)(vi) and the modifications listed in subsections (b)(2)(ix) and (b)(2)(x) of §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the components [Reference 4.7.1-2 , ¶ (g)(4)]. In addition, concrete containment pressure retaining components and their integral attachments, and the post-tensioning systems of concrete Containments, must meet the inservice inspection and repair requirements applicable to components classified as ASME Code Class CC [Reference 4.7.1-2, ¶(g)(4)(v)(C)].

Inservice examination of components and system pressure tests conducted during successive 120-month inspection intervals, following the initial 120-month inservice inspection interval, must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in §50.55a(b) twelve months prior to the start of the 120-month inspection interval, subject to the limitations and modifications listed in paragraph §50.55a(b) [Reference 4.7.1-2, ¶ (g)(4)(ii)].

The *Containment Inservice Inspection Plan* for each inservice inspection interval of the license renewal term will :

(1) Implement the examination requirements of either:

(a) §50.55a (61 *Federal Register* 41303, dated 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 listed in subsections (b)(2)(ix) and (b)(2)(x) of §50.55a, or

(b) the edition of the ASME Section XI Code required by §50.55a(b) prior to the start of the 120-month inservice inspection interval, 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;

(2) Comply with §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 §50.55a(5)(iv), for Commission evaluation.

The *Containment Inservice Inspection Plan* includes the examination requirements needed to comply with both ASME Code Section XI Subsection IWE and Subsection IWL. These subsections are described individually below.

4.8.1 ASME Section XI, Subsection IWE Examinations

Because loss of coatings can lead to corrosion of the underlying base metal which is required to maintain the essentially leaktight barrier of the Containment structure, Subsection IWE requires that accessible coated surfaces be visually examined for evidence of conditions that could indicate degradation of the coated surface. Subsection IWE also requires surfaces which are uncoated or where coatings loss has occurred be visually examined for conditions which could indicate potential loss of material due to corrosion or other degradation of the underlying base metal. Because moisture barriers are an important defense against corrosion, they are examined for conditions which may permit intrusion of moisture against inaccessible containment metallic surfaces. Bolting materials are required to be examined for conditions which may cause the bolted connection to violate either the leak-tight or structural integrity.

4.8.1.1 Program Description

Purpose - The purpose of the ASME Section XI, Subsection IWE examinations is to identify and correct degradation of the accessible steel surfaces of the containment liner prior to the loss of the essentially leak tight barrier.

Scope - The scope of the ASME Section XI Subsection IWE inservice inspection currently covers accessible surface areas, including surfaces of welds, pressure-retaining bolting, and moisture barriers intended to prevent intrusion of moisture against inaccessible containment metallic surfaces.

Aging Effects or Relevant Conditions - Loss of material of the steel surfaces is the aging effect of concern.

Method - The *Containment Inservice Inspection Plan* will include the following examination categories:

- 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,* and
- 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.

Some steel surfaces of the Containment liner are inaccessible for examination. Section 50.55a(b)(2)(x)(A) requires an evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - ASME Code Section XI, Subsection IWE provides rules for inservice inspection, repair, and replacement of Class MC pressure retaining components and their integral attachments and of metallic shell and penetration liners of Class CC pressure retaining components and their integral attachments in light-water cooled power plants. Section 50.55a clarifies that these rules are also applicable to metal containments and metallic liners of concrete containments that are not stamped Class MC or CC components. Except as specified in §50.55a(b)(2)(x), embedded or inaccessible portions of the containment vessels, parts, and appurtenances are exempt from examination or evaluation.

Frequency - The frequency of examinations is specified in IWE-2400. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation. Subsection IWE examinations are performed during each ISI period, which is similar to the frequency of 10CFR50, Appendix J inspections which are currently conducted three times every ten years.

Acceptance Criteria or Standard - Acceptance standards for Subsection IWE examinations are specified in IWE-3500.

Corrective Action - Areas of degradation are found acceptable through engineering evaluation or corrected by repair or replacement in accordance with Subsection IWE. Requirements for repairs and re-examination are specified in IWA-4000. Re-examination results are required to meet the acceptance standards of IWE-3500. Supplemental examinations in accordance with IWE-3200 are performed when specified as a result of the engineering evaluation.

Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee *Containment Inservice Inspection Plan* is implemented by procedures that are developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - The Oconee *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 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."

In addition, the Oconee Improved Technical Specifications, Specification SR 3.6.1.3 requires a verification of containment structural integrity. This specification will be revised to refer to the Oconee *Containment Inservice Inspection Plan*.

4.8.1.2 Operating Experience and Demonstration

Subsection IWE (which has been developed by and will continue to be maintained through the consensus process of the ASME Code) 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 [Reference 4.7.1-3] 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. The Commission's process of reviewing Editions and Addenda of the ASME Boiler and Pressure Vessel Code, and incorporating them into §50.55a with limitations and modifications as required, provides additional assurance of the effectiveness of this program.

Based on the above review, the implementation of the Subsection IWE Examinations of the *Containment Inservice Inspection Plan,* in conjunction with the *Coatings Program* (see Section 4.7) and the *Containment Leak Rate Testing Program*, provide reasonable assurance that the aging effects will be managed such that the Containment steel components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The *Containment Leak Rate Testing Program* (see Section 4.7.1) complements the Subsection IWE examinations and provide 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.

4.8.2 ASME Section XI, Subsection IWL Examinations

Because corrosion could lead to a crack or break in tendon wires or anchorage, thereby rendering the tendon unable to maintain the compressive force on the structure during an accident, tendon wires and anchorage are required to be inspected and monitored for corrosion. Subsection IWL requires an inspection of a random sample of post-tensioning system components. In addition to inspecting for corrosion, tendon wires are required to be examined for mechanical damage. The condition of tendon anchorage areas is also required to be examined for cracking in anchor heads, shims, and bearing plates; broken or unseated wires; broken strands and detached buttonheads; and evidence of free water. Adjacent concrete is required to be inspected for cracks.

4.8.2.1 Program Description

Purpose - The purpose of the ASME Section XI, Subsection IWL examinations 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. The Subsection IWL examinations also identify and correct degradation of concrete surfaces of the Reactor Building (Containment).

Scope - The scope of the ASME Section XI Subsection IWL inservice inspection covers reinforced concrete and the post-tensioning systems of concrete containments.

Aging Effects or Relevant Conditions - Loss of material and cracking of the tendon wires and anchorage, grease degradation, concrete cracking and change in material properties are the aging effects of concern.

Method - Subsection IWL requires visual examination of tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, wedges, buttonheads, shims, and the adjacent concrete.

The *Containment Inservice Inspection Plan* will include the following examination categories:

- Examination Category L-A, *Concrete*
- Examination Category L-B, *Unbonded Post-Tensioning System*

Tendon force and elongation are required to be measured to evaluate the prestressing force of the system. In addition, tendon wires or strand samples are required to be removed and tested to determine the yield strength, ultimate tensile strength and elongation. The corrosion protection medium is analyzed to determine reserve alkalinity, water content, and soluble ion concentrations within the limits specified in

Table IWL-2525-1. Free water samples are tested for pH. Visual examination requirements, personnel qualification requirements, and requirements for evaluation of examination results are specified in IWL-2300.

Some surfaces of Containment concrete components are inaccessible for examination. Section 50.55a(b)(2)(x)(A) requires an evaluation of the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - ASME Code Section XI, Subsection IWL provides requirements for inservice inspection and repair or replacement activities of the post-tensioning systems of concrete containments. Except as specified in §50.55a(b)(2)(ix)(E), concrete, tendons and tendon end anchorages that are inaccessible are exempt from Subsection IWL requirements.

Frequency - The frequency of inspection is specified in IWL-2400. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard - Acceptance standards are specified in IWL-3000.

Corrective Action - Requirements for repair or replacement activities are specified in IWL-4000 and IWL-7000. Specific corrective actions will be taken in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee *Containment Inservice Inspection Plan* is implemented by procedures that are developed and maintained in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - The Oconee *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 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.”

4.8.2.2 Operating Experience and Demonstration

Subsection IWL (which has been developed by and will continue to be maintained through the consensus process of the Code) is expected to be effective in managing corrosion of the post-tensioning system because it contains examination requirements similar to Regulatory Guide 1.35. Furthermore, NUREG/CR-6424 concurs that current examination programs appear adequate to ensure the continuing physical integrity of post-tensioning systems [Reference 4.7.1-4]. The Commission's process of reviewing Editions and Addenda of the ASME Boiler and Pressure Vessel Code, and incorporating them into §50.55a with limitations and modifications as required, provides additional assurance of the effectiveness of this program.

In December 1997, during the Oconee Unit 1 tendon surveillance required by Oconee Custom Specification 4.4.2, some precursor conditions of abnormal tendon degradation were observed [Reference 4.7.1-5]. These precursor conditions were 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 Regulatory Guide 1.35, Revision 3 [Reference 4.7.1-6]. 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 Regulatory Guide 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 implementation of the Subsection IWL Examinations of the *Containment Inservice Inspection Plan* provides reasonable assurance that the aging effects will be managed such that the Containment post-tensioning system will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.8.3 References for Section 4.8

4.8-1. 61 FR 41303, August 8, 1996, Codes and Standards for Nuclear Power Plants; Subsection IWE and Subsection IWL, Final Rule.

4.8-2. 10 CFR, §50.55a, *Codes and Standards.*

4.8-3. NUREG-1540, *BWR Steel Containment Corrosion,* April 1996.

4.8-4. NUREG/CR-6424, *Report on Aging of Nuclear Power Plant Reinforced Concrete Structures.*

4.8-5. W. R. McCollum (Duke) letter dated December 31, 1997 to Document Control Desk (NRC), *Reactor Containment Building Tendon Surveillance #7,* Oconee Nuclear Station, Unit 1, Docket No. 50-269.

4.8-6. Regulatory Guide 1.35, Revision 3, *Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments,* July 1990.

4.9 CONTAINMENT LEAK RATE TESTING PROGRAM

One of the conditions of all operating licenses for water-cooled power reactors is that Containment shall meet the leakage test requirements set forth in 10 CFR Part 50, Appendix J. The purposes of these tests are to assure that:

(a) 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) periodic surveillances of Containment Penetrations and isolation valves are performed.

The *Containment Leak Rate Testing 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 aging management programs for license renewal. Each of these test programs is described in the following sections.

4.9.1 REACTOR BUILDING TYPE A INTEGRATED LEAK RATE TEST

The *Reactor Building Type A Integrated Leak Rate Test* has the following attributes. In addition, because this is an existing program, operating experience and demonstration are provided, as applicable.

4.9.1.1 Program Description

Purpose - The purpose of the Type A Integrated Leak Rate Test (ILRT) is to detect severe corrosion that could cause a breach of the pressure boundary of the Containment steel components.

Scope - The Type A ILRT measures the leak rate of the Containment under conditions as prescribed in 10 CFR Part 50, Appendix J [Reference 4.9-1]. Pressure boundary components including the liner, penetrations, and hatches are tested.

Aging Effects - Loss of material that could result in containment leakage is the relevant condition which the Type A ILRT identifies.

Method - The Type A ILRT measures leakage by pressurizing the Containment to the peak calculated containment internal pressure for the design basis loss of coolant accident as specified in Oconee Improved Technical Specifications, 5.5.2, *Containment Leakage Rate Testing Program.*

Sample Size - Not applicable for an existing program.

Industry Code or Standards - Guidance for the *Containment Leakage Rate Testing Program* is contained in Regulator Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

Frequency - The Type A ILRT was previously performed three times during a ten year period. It is now performed once every ten years in accordance with Option B in Appendix J to 10 CFR Part 50.

Acceptance Criteria or Standard - Acceptable leakage rates are established in Oconee Improved Technical Specifications, ITS 3.6.1, *Containment* and 5.5.2, *Containment Leakage Rate Testing Program* [Reference 4.9-2].

Corrective Action - Corrective actions are taken in accordance with the requirements of 10 CFR Part 50, Appendix J and the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee Type A ILRT is implemented by written procedures as required by Oconee ITS 5.4, *Administrative Controls, Procedures,* and in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - The requirements for containment Type A leak rate testing are contained in 10 CFR §50.54(o) and 10 CFR Part 50, Appendix J. Additional requirements are provided in Oconee Improved Technical Specifications 3.6.1, *Containment* and 5.5.2, *Containment Leakage Rate Testing Program.*

4.9.1.2 Operating Experience and Demonstration

More than twenty Type A ILRT have been performed for the Oconee Containments. Results have shown that all containment steel components have successfully passed the Type A ILRT.

Based on the review of Oconee operating experience, the continued implementation of the Oconee Type A ILRT complements the Subsection IWE Inservice Examinations (see Section 4.8.1) and together provide reasonable assurance that the aging effects will be managed such that the Containment will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.9.2 REACTOR BUILDING TYPE B LOCAL LEAK RATE TEST

The *Reactor Building Type B Local Leak Rate Test* has the following attributes. In addition, because this is an existing program, operating experience and demonstration are provided, as applicable.

4.9.2.1 Program Description

Purpose - The purpose of the Type B Local Leak Rate Test (LLRT) is to provide a means to detect leakage which could indicate degradation of resilient seals and gaskets of Containment airlocks and hatches, as required by 10 CFR Part 50, Appendix J. The localized test will also provide a means of detecting severe corrosion of the metallic surfaces of the air locks and hatches.

Scope - The Type B LLRT measures the leak rate of the pressure boundary components under conditions as prescribed in 10 CFR Part 50, Appendix J. Resilient seals and gaskets of airlocks and hatches are within the scope of this program.

Aging Effects - The applicable aging effects include change in material properties, cracking and loss of material.

Method - The Type B leak rate test measures leakage by pressurizing the penetration to the specified test pressure.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - Guidance for the *Containment Leakage Rate Testing Program* are contained in Regulator Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995.

Frequency - Frequency of inspection is in accordance with 10 CFR Part 50, Appendix J, Option A, Section III.D.2. and Option B, Section III.B.

Acceptance Criteria or Standard - Acceptable leakage rates are established in accordance with the requirements of 10 CFR Part 50, Appendix J.

Corrective Actions - Specific corrective actions will be implemented in accordance with the requirements of 10 CFR Part 50, Appendix J and the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee Type B LLRT is implemented by written procedures that are maintained in accordance the *Duke Quality Assurance Program.*

Regulatory Basis - The requirements for containment Type B leak rate testing are contained in 10 CFR §50.54(o) and 10 CFR Part 50, Appendix J. Additional requirements are provided in Oconee Improved Technical Specifications 3.6.1, *Containment* and 5.5.2, *Containment Leakage Rate Testing Program.*

4.9.2.2 Operating Experience and Demonstration

Numerous Type B LLRT have been performed at Oconee 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 non-metallic 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 Oconee Type A ILRT and Type B LLRT, which complement the ASME Section XI, Subsection IWE Inservice Examination, provide reasonable assurance that the aging effects will be managed such that the Containment will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.9.3 References for Section 4.9

4.9-1. Appendix J to 10 CFR Part 50 - *Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors.*

4.9-2. Oconee Nuclear Station Improved Technical Specifications.

4.10 CONTROL ROD DRIVE MECHANISM NOZZLE AND OTHER VESSEL CLOSURE PENETRATIONS INSPECTION PROGRAM

Section 2.4.5 of OLRP-1001 and BAW-2251 [Reference 4.10-1] identify the control rod drive mechanism (CRDM) nozzles and other vessel closure penetrations as subject to aging management review. Section 3.4.5 of OLRP-1001 and BAW-2251 identify primary water stress corrosion cracking (PWSCC) as an aging effect of concern that must be managed for the period of extended operation. The *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* in conjunction with the *Chemistry Control Program* (see Section 4.6), *Inservice Inspection Plan* (see Section 4.18), *Reactor Coolant System Operational Leakage Monitoring* (see Section 4.23)*, and Boric Acid Wastage Surveillance Program* (see Section 4.5) will manage PWSCC for the period of extended operation. The *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* has the following attributes. In addition, because *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* is an existing program, operating experience and demonstration are provided, as applicable.

4.10.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* is to verify the assumptions made in the BWOG safety evaluation of the susceptibility and consequence of PWSCC in B&W-designed CRDM nozzles by gathering additional inspection information in order to better characterize PWSCC.

Scope - The scope of the program includes reactor vessel closure head CRDM nozzles for all three units and the Oconee Unit 1 thermocouple penetrations.

Aging Effects - The applicable aging effect is PWSCC of Alloy 600 nozzles with partial penetration welds that cause high circumferential residual stresses on the inner diameter of the nozzles opposite the welds.

Method - The current program requires the re-inspection of from two to twelve Oconee Unit 2 CRDM nozzles from the top of the head in 1999. Eddy Current inspection will be utilized for detection. eddy current, ultrasonic, and liquid penetrate will be used for sizing.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - The inspection frequency is dependent on plant-specific, B&WOG, and industry-wide inspection results. The next Oconee Unit 2 inspections are planned for 1999. Future inspections will be established upon review of the next set of inspection results.

Acceptance Criteria or Standard - Axial flaws detected during inspection will be analyzed and evaluated using the NUMARC acceptance criteria which were approved by the NRC in their Safety Evaluation dated November 19, 1993. Circumferential flaws will be analyzed and addressed with the NRC on a case-by-case basis [Reference 4.10-2].

Corrective Action - Flaws that cannot be justified for continued service by analysis will be repaired in accordance with ASME Section XI. Flaws that can be justified for continued service become a time-limited aging analysis and are addressed by the Oconee *Thermal Fatigue Management Program* (see Section 5.4 of OLRP-1001). Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Duke response to NRC Generic Letter 97-01 [Reference 4.10-3].

4.10.2 Operating Experience and Demonstration

Since the NRC acceptance of inspection techniques [Reference 4.10-2], a full inspection of Oconee Unit 2 from beneath the reactor vessel head was performed in 1994. In addition, a re-inspection was completed on two Oconee Unit 2 CRDM nozzles in 1996 from above the reactor vessel head. The results of these inspections were submitted to the NRC by Duke letters dated September 22, 1994 [Reference 4.10-4] and April 30, 1996 [Reference 4.10-5]. The Oconee Unit 2 inspections identified a small number of nozzles with crack-like indications that were insignificant in depth. Re-inspection showed no growth after one cycle of operation. Future inspections will be performed in a manner consistent with these previous inspections.

Based on the above review, the continued implementation of the *CRDM Nozzle and Other Vessel Closure Penetrations Inspection Program* provides reasonable assurance that the aging effects will be managed such that the CRDM nozzle and other vessel closure penetrations will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.10.3 References for Section 4.10

4.10-1. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel*, The B&W Owners Group Generic License Renewal Program, June 1996.

4.10-2. W. T. Russell (NRC) letter dated November 19, 1993 to W. H. Rasin (NUMARC, now NEI).

4.10-3. M. S. Tuckman (Duke) letter dated July 30, 1997 to Document Control Desk (NRC), Oconee Nuclear Station - Response to Generic Letter 97-01: *Degradation of Control Rod Drive Mechanism Nozzle and Other Vessel Closure Head Penetrations,* Docket Nos. 50-269, -270, and -287.

4.10- 4. J. W. Hampton (Duke) letter dated September 22, 1994 to Document Control Desk (NRC), *Acceptance Criteria for Control Rod Drive Mechanism Penetration Inspection*, Docket Nos., 50-269, -270, and -287.

4.10- 5. J. W. Hampton (Duke) letter dated April 30, 1996 to Document Control Desk (NRC), *Interim Engineering Evaluation of Control Rod Drive Mechanism (CRDM) Penetration Inspections*, Oconee Unit 2, Docket No. 50-270.

4.11 CRANE INSPECTION PROGRAM

Section 2.7.2.2 of OLRP-1001 identifies that cranes rails and girders are subject to aging management review. Section 3.7.2.2 identifies loss of material as an applicable aging effect for steel components in an air environment. The *Crane Inspection Program* will be utilized to manage the aging effect for the period of extended operation. The *Crane Inspection Program* has the following attributes. In addition, because the *Crane Inspection Program* is an existing program, operating experience and demonstration are provided, as applicable.

4.11.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Crane Inspection Program* is to provide periodic inspections and preventive maintenance on Oconee cranes and hoists. A subset of the many inspection activities performed under the auspices of the *Crane Inspection Program* is the inspection of the structural components.

Scope - Structural components associated with the following cranes and hoists are included in the *Crane Inspection Program* for license renewal:

Building	Crane
Auxiliary Building	Spent Fuel Bay Crane
	Spent Fuel Pool Fuel Handling Crane
	Hoists located over safety-related equipment
Keowee	270 Ton Crane
	Intake Hoist
	Hoists located over safety-related equipment
Reactor Building	Polar Crane
	2 Ton CRDM Service Crane
	Main Fuel Handling Bridge
	Equipment Hatch Hoist
	Hoists located over safety-related equipment
Turbine Building	Pump Aisle Crane
	Turbine Aisle Crane
	Turbine Aisle Auxiliary Crane
	Heater Bay Crane
	Hoists located over safety-related equipment
Standby Shutdown Facility	Hoists located over safety-related equipment

A list of hoists located over safety-related equipment is maintained at Oconee.

Aging Effects - The applicable aging effect is loss of material due to corrosion of the steel components.

Method - The program requires visual inspections of cranes and hoists within the scope.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - ANSI B30.2.0 [Reference 4.10-1] for cranes and ANSI B30.16 [Reference 4.1-2] for hoists.

Frequency - Each crane and hoist is subject to several inspections. The inspection frequencies for the cranes are based on the guidance provided by ANSI B30.2.0. The inspection frequencies for hoists are based on guidance provided by ANSI B30.16. Oconee experience supports the established frequency as being timely and effective.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material as determined by the accountable engineer.

Corrective Action - Items which do not meet the acceptance criteria are repaired or replaced. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Crane Inspection Program* is implemented by written procedure in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - 29 CFR Chapter XVII, §1910.179 [Reference 4.1-3].

4.11.2 Operating Experience and Demonstration

The crane inspection requirements are comprehensive and cover the portions of the crane within the scope of license renewal. Results of previous inspections at Oconee has revealed paint flaking on the crane girders, but an intact base coat of paint. No corrosion or rust has been identified. Bolts on the crane girders have been inspected and some have required retightening. This type of retightening is not unexpected. The rails on the Turbine Aisle Crane have been replaced due to wear. The wear was attributed to misalignment during installation of the rails.

Based on the above review, the continued implementation of the *Crane Inspection Program* provides reasonable assurance that the aging effects will be managed such that the identified cranes and hoists will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.11.3 References for Section 4.1

4.11-1. ANSI B30.2.0, "Overhead and Gantry Cranes", American National Standard, Section 2-2, *Safety Standards for Cableways, Cranes, Derricks, Hoists, Hooks, Jacks and Slings*, The American Society of Mechanical Engineers, New York.

4.11-2. ANSI B30.16, "Overhead Hoists (Underhung)", The American Society of Mechanical Engineers, New York.

4.11-3. 29 CFR Chapter XVII, §1910.179, *Occupational Safety and Health Administration, Overhead and Gantry Cranes.*

4.12 DUKE POWER FIVE-YEAR UNDERWATER INSPECTION OF HYDROELECTRIC DAMS AND APPURTENANCES

Section 2.7.6 of OLRP-1001 identifies the Keowee Intake Structure, Spillway, and Powerhouse as subject to aging management review. The applicable aging effects are identified in Section 3.7.6 and include loss of material due to corrosion for steel components and loss of material, cracking, and change in material properties of concrete components. The *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances* will manage these applicable aging effects for the period of extended operation. The *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances* has the following attributes. In addition, because *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances* is an existing program, operating experience and demonstration are provided, as applicable.

4.12.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances* is to inspect the structural integrity of the Keowee intake structure, spillway, and powerhouse.

Scope - The scope of the *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances* includes:

- Keowee Intake - trashracks, support steel and concrete
- Spillway - concrete
- Powerhouse - concrete

Aging Effects - The applicable aging effects include loss of material due to corrosion for steel components and loss of material, cracking, and change in material properties of concrete components.

Method - The program requires visual examinations of external surfaces.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed once every five years. The inspection frequency is consistent with the periodicity of inspections performed by FERC for maintaining other components of the structures (See *FERC Five Year Inspections* Section 4.15).

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material, cracking, or change in material properties as determined by the accountable engineer.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated by the accountable engineer. If repair or replacement is required, then specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - This program currently is performed in accordance with written guidance developed by the responsible Duke Power department.

Regulatory Basis - 18 CFR Part R, *Water Power Project Works Safety*.

4.12.2 Operating Experience and Demonstration

Underwater inspections have been performed for the Keowee structures since 1978. A review of previous *Duke Power Five Year Underwater Inspections of Hydroelectric Dams and Appurtenances* conducted at Keowee confirms the reasonableness and acceptability of the inspection frequency in that degradation of the underwater portions of the concrete and steel components is detected prior to loss of function.

Previous *Duke Power Five-Year Underwater Inspections of Hydroelectric Dams and Appurtenances* have revealed only minor degradation. Observations include loss of material due to corrosion of steel components and loss of material of concrete components. The concrete degradation was identified as resulting from inadequate vibration during construction and was not associated with aging. Other than the degradation noted, concrete was determined to be in good condition. Where corrosion of steel components has been identified, the steel has been repaired or replaced.

Based on the above review, the continued implementation of the *Duke Power Five-Year Underwater Inspection for Dams and Appurtenances* provides 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.

4.13 Duke Quality Assurance Program

As background, Duke Energy Corporation (Duke) maintains full responsibility for assuring that its nuclear power plants are designed, constructed, tested and operated in conformance with good engineering practices, applicable regulatory requirements and specified design bases and in a manner to protect the public health and safety. To this end, Duke has established and implemented a Quality Assurance Program which conforms to the criteria established in 10 CFR Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" published June 27, 1970 (35 *Federal Register* 10499) and amended September 17, 1971 (36 FR 18301) and amended January 20, 1975 (40 *Federal Register* 3210).

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 Oconee UFSAR [Reference 4.13-1]. The Quality Assurance Program addresses all aspects of quality assurance at Duke's nuclear power stations. Two of these aspects that are pertinent to the aging management programs identified for license renewal are "Corrective Actions" and "Document Control" which are briefly described below. Additional descriptions are provided in DUKE-1A [Reference 4.13-2].

4.13.1 Corrective Action

Station personnel are responsible for the implementation of the quality assurance program as it pertains to the performance of their activities. Specific to this responsibility is the requirement for either informing responsible supervisory personnel or for taking appropriate corrective action in response to deficient implementation of program requirements.

Procedures require that conditions adverse to quality be corrected. In the case of significant conditions adverse to quality (more significant events), the procedures assure that the cause of the condition is determined and that action is taken to preclude repetition. Performance and verification personnel are to:

- identify conditions that are adverse to quality,
- suggest, recommend, or provide solutions to the problems, and
- verify resolution of the issue.

Additionally, performance and verification personnel are to ensure that reworked, repaired, and replacement items are inspected and tested in accordance with the original inspection and test requirements or specified alternatives.

Discrepancies revealed during the performance of station operation, maintenance, inspection and testing activities must be resolved prior to verification of the completion of the activity being performed. In the event of the failure of QA Condition 1 structures, systems, and components, the cause of the failure is evaluated and appropriate corrective action is taken. Items of the same type are evaluated to determine whether or not they can be expected to continue to function in an appropriate manner. This evaluation is documented in accordance with applicable procedures.

4.13.2 DOCUMENT CONTROL

The Duke Quality Assurance Program requires that specific operational activities associated with QA Condition 1 structures, systems, and components be accomplished in accordance with procedures, instructions, drawings, and checklists appropriate to the nature of the activities being performed. As necessary, such documents identify equipment necessary to perform an activity, specify conditions which must exist prior to and during performance of an activity, and include quantitative or qualitative acceptance criteria, compatible with any applicable design specifications, for determining that the activity addressed is satisfactorily accomplished. Also, the procedure will require independent verification by qualified personnel of the performance of specific procedural steps. Examples of documents that address quality-related operational activities are:

- Preoperational Test Procedures
- Periodic Test Procedures
- Operating Procedures
- Maintenance Procedures
- Instrument Procedures
- Chemistry Procedures

Station procedures which address activities associated with QA Condition 1 structures, systems and components are subjected to a well-defined, established review and approval process. This process includes the requirement that each procedure be reviewed for adequacy by an individual or group other than the individual or group which prepared the procedure.

Maintenance, instrumentation and modification procedures are reviewed by cognizant station personnel to determine the need for inspections. Procedures for inspections identify the certifications, inspection methods, acceptance criteria, and provide means for documenting inspection results.

4.13.3 References for Section 4.13

4.13-1. *Oconee Nuclear Station, Updated Final Safety Analysis Report*, as revised.

4.13-2. *Duke-1-A, Duke Energy Corporation Topical Report, Quality Assurance Program.*

4.14 ELEVATED WATER STORAGE TANK CIVIL INSPECTION

Section 2.7.10.3 of OLRP-1001 identifies the Elevated Water Storage Tank as subject to aging management review. Section 3.7.10.3 of OLRP-1001 identifies the aging effect applicable to the interior and exterior surfaces of the Elevated Water Storage Tank as loss of material due to corrosion. The *Elevated Water Storage Tank Civil Inspection* will manage this aging effect for the period of extended operation. The *Elevated Water Storage Tank Civil Inspection* has the following attributes. In addition, because the *Elevated Water Storage Tank Civil Inspection* is an existing program, operating experience and demonstration are provided, as applicable.

4.14.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Elevated Water Storage Tank Civil Inspection* is to provide a visual examination of the interior and exterior surfaces of the tank and associated components to ensure their structural integrity.

Scope - The scope of the program includes the interior and exterior surfaces of the Elevated Water Storage Tank and associated components.

Aging Effects - The applicable aging effect is loss of material due to corrosion.

Method - The program requires visual examinations of internal and external surfaces in accordance with station procedures.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems.*

Frequency - Inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of loss of material due to corrosion as determined by the accountable engineer.

Corrective Action - Items that do not meet the acceptance criteria are evaluated for continued service, monitored, or corrected. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Elevated Water Storage Tank Inspections* are implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - This program has no current regulatory basis.

4.14.2 Operating Experience and Demonstration

A review of previous *Elevated Water Storage Tank Civil Inspections* conducted at Oconee confirms the reasonableness and acceptability of the inspection frequency in that degradation of the tank is detected prior to loss of function. The inspection frequency is consistent with the guidance in NFPA 25, *Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*. The first inspection of the tank identified corrosion, but no metal loss. The corrosion was removed, and the metal was recoated. The most recent inspection of the elevated water storage tank did not identify any deficiencies in the coating, corrosion, or metal loss. Sludge has been found in the tank during these inspections and has been subsequently cleaned out so that the tank could be inspected. The sludge did not impact the ability of the tank to maintain inventory for the High Pressure Service Water System. The foundation was in good condition with no cracking or deterioration.

Based on the above review, the continued implementation of the *Elevated Water Storage Tank Civil Inspections* provides reasonable assurance that the aging effects will be managed such that the Elevated Water Storage Tank will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.15 FEDERAL ENERGY REGULATORY COMMISSION (FERC) FIVE YEAR INSPECTION

Sections 2.7.4 and 2.7.6 of OLRP-1001 identify the earthen embankments and Keowee concrete components that are subject to aging management review. Sections 3.7.4 and 3.7.6 of OLRP-1001 identify the applicable aging effects for the earthen embankments and concrete in the Keowee Intake, Powerhouse, and Spillway. The *FERC Five Year Inspection* is credited with managing these aging effects. The *FERC Five Year Inspection* has the following attributes. In addition, because the *FERC Five Year Inspection* is an existing program, operating experience and demonstration are provided, as applicable.

4.15.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *FERC Five Year Inspection* is to assess the conditions affecting the safety of a hydroelectric project or project works.

Scope - The scope of the *FERC Five Year Inspection* at Oconee includes: Keowee River Dam; Little River Dam; Little River Dikes A, B, C, and D; Oconee Intake Canal Dike; Keowee Spillway and Left Abutment, Keowee Intake and Powerhouse.

Aging Effects - The inspection detects the following aging effects:

- Concrete - Cracking, spalling, loss of material due to erosion, settlement, and movement of concrete structures
- Earthen - Settlement, movement, loss of material due to erosion and seepage, leakage, cracking, sinkholes, internal stress and hydrostatic pressure of earthen structures

Method - The program requires visual examination of external surfaces by an independent consultant approved by FERC.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - *Federal Guidelines for Dam Safety* [Reference 4.15-1]

Frequency - This inspection is required to be performed every five years.

Acceptance Criteria or Standard - Acceptability of structure is based on the knowledge of the qualified independent consultant.

Corrective Action - A corrective action plan and schedule are provided to FERC no later than 60 days after the independent consultant report is filed with FERC. The plan and schedule are approved by FERC. Incorporation of the consultant recommendations are reviewed during subsequent inspections.

Any identified earthen embankment seepage is monitored for sedimentation, change in color of sediment, and increase in flow. Minor saturated areas are monitored for any change such as flow of water on the ground surface, boils, or transportation of soil. Trench drains or drainage blankets are installed where necessary. Erosion is corrected as part of the routine maintenance program

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - Inspection, documentation, and retention are in accordance with the requirements in 18 CFR Part 12 Subpart D.

Regulatory Basis - 18 CFR Part 12, *Water Power Projects and Project Works Safety* [Reference 4.15-2].

4.15.2 Operating Experience and Demonstration

The initial FERC Five Year Inspection was performed in 1976 on the Keowee Project. There have been a total of five inspections performed. FERC Five Year Inspections have revealed only minor degradation. Observations include seepage at the toe of Little River Dam, minor saturation of areas of the little River Dam, erosion of the shoreline at Little River Dam, seepage at the toe of Little River Dike A, slight seepage at the low point of Dike D, minor saturation of an area in the Intake Canal Dike, minor erosion at abutments to the Intake Canal Dike, seepage from Keowee River Dam, and erosion at the downstream toe of Keowee River Dam. Inspection of the earthen structures showed no outward signs of leakage, damage, settlement or movement. The general appearance and condition of the earthen structures remains acceptable though all inspections. All seepage is well controlled and monitored [References 4.15-3, 4.15-4, 4.15-5, 4.15-6, and 4.15-7].

The Keowee spillway, intake and powerhouse were found to be in satisfactory condition during previous inspections. The concrete was determined to be in good condition with slight trace of efflorescence in random locations. A few hairline cracks were observed in the spillway wingwalls. Minor cracking was noted in the floor of the powerhouse. Efflorescence was noted in several areas on the powerhouse. Slight rust was found in steel components of the spillway, but overall, the steel is in satisfactory condition. The observed aging effects are minor and have no impact on the ability of the Keowee Project structures to perform their intended functions.

Based on the above review, the continued implementation of the *FERC Five Year Inspection* provides reasonable assurance that the aging effects will be managed such that the earthen embankments and Keowee Intake, Powerhouse, and Spillway concrete components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.15.3 References for Section 4.15

4.15-1. *Federal Guidelines for Dam Safety*, prepared by the Ad Hoc Interagency Committee on Dam Safety of the Federal Coordinating Council for Science Engineering and Technology, Washington, D. C., June 25, 1979.

4.15-2. 18 CFR Part 12 - *Safety of Water Power Projects and Project Works*, 59 FR 54815, Nov. 2, 1994.

4.15-3. Duke Power Company Keowee Development F. P. C. Project No. 2503, Inspection and Report by Chas. T. Main, Inc., April, 1976.

4.15-4. Duke Power Company Keowee Development F. P. C. Project No. 2503, Inspection and Report by Chas. T. Main, Inc., February, 1981.

4.15-5. Duke Power Company Keowee Development F. P. C. Project No. 2503, Third Five Year Independent Consultant Inspection, Law Engineering Testing Company, March, 1986.

4.15-6. Duke Power Company Keowee Development F. P. C. Project No. 2503, Fourth Five Year Independent Consultant Inspection, Law Engineering Testing Company, April, 1991.

4.15-7. Keowee Hydroelectric Development FERC Project No. 2503-SC, Fifth Five-Year Safety Inspection, Northrop, Devine & Tarbell, Inc., March, 1996.

4.16 FIRE PROTECTION PROGRAM

The Oconee *Fire Protection Program* utilizes the concept of defense-in-depth to achieve its required high degree of fire safety. This concept includes:

- Preventing fires from starting
- Detecting and suppressing fires quickly to limit their damage
- 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 Oconee *Fire Protection Program* contains many activities to achieve this defense-in-depth and to minimize the impacts of a potential fire at Oconee. Two of these activities which are included as aging management programs for license renewal are:

- Fire Barrier Inspections
- Fire Water System Testing

These two activities are described in the following:

4.16.1 FIRE BARRIER INSPECTIONS

Section 2.7.2.4 of OLRP-1001 identifies fire doors, fire walls and fire barrier penetration seals as subject to aging management review. Section 3.7.2.4 of OLRP-1001 identifies the aging effects that are applicable to fire walls, fire doors, and fire barrier penetration seals, respectively, during the period of extended operation. *Fire Barrier Inspections* will manage these aging effects such that the intended functions of the fire barriers will be maintained in accordance with the current licensing basis during the period of extended operation. The *Fire Barrier Inspections* has the following attributes. In addition, because *Fire Barrier Inspections* are part of an existing program, operating experience and demonstration are provided, as applicable.

4.16.1.1 Program Description

Purpose - The purpose of *Fire Barrier Inspections* is to perform periodic inspections and preventive maintenance on fire barriers and fire doors to assure that they continue to perform their functions.

Scope - The scope includes Units 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.

Aging Effects - For fire barrier penetration seals - cracking, separation from walls or components; separation of layers of material, rupture or puncture of seal, cracking.

For fire barrier walls, ceilings, and floors - loss of material.

For fire doors - self-closing doors are visually inspected to verify that hinges are complete with all screws tight and pins are in good condition. Double self-closing doors are visually inspected to verify that bolts are in good condition and the astragal (metal molding strip) is in good condition. Automatic-closing doors are visually inspected to verify tracks, trucks, cables, and chains are in good operating condition. Hollow metal fire doors are visually inspected for holes in the skin of the door.

Method - The program requires visual examination of fire barriers.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - At least once every 18 months, exposed surfaces of fire walls are visually inspected and at least 10% of each type of fire barrier penetration seal is inspected. Fire doors are visually inspected bi-monthly and functionally tested bi-monthly. The frequency of inspections has been in effect since the initial implementation of the technical specification requirements at Oconee in 1977 and is considered acceptable based on industry operating experience.

Acceptance Criteria or Standard - For fire barrier penetration seals, no visual indication of cracking, separation from wall, separation of layers of material, holes and ruptures or puncture of seal. For walls, ceilings, and floors the acceptance criteria are no visual indication of holes or cracks. For fire doors, the acceptance criteria are no indication of loss of material (e.g., punctures).

Corrective Action - Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Fire Barrier Inspections* are being implemented by plant procedures as part of the Selected Licensee Commitment 16.9.5 and controlled by the *Duke Quality Assurance Program.*

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Regulatory Basis - 10 CFR §50.48 [Reference 4.16-1], 10 CFR 50, Appendix R [Reference 4.16-2], Oconee Facility Operating License, License Condition 3.E [Reference 4.16-3], Oconee UFSAR Chapter 16, Selected Licensee Commitments, SLC 16.9.5 [Reference 4.16-4].

4.16.1.2 Operating Experience and Program Demonstration

A review of the *Fire Barrier Inspections* conducted at Oconee confirms the reasonableness and acceptability of the inspection frequency in that degradation of the fire barrier is detected prior to loss of function. Identified deficiencies are associated with installation problems and missing tags for the fire barrier penetration seals. Previous inspections of the fire doors have identified wear of the hinges and handles. Holes in the skin of doors have been identified in inspections. These holes have been determined to be the result of installation of signs on the doors and are not due to aging.

Based on the above review, the continued implementation of the *Fire Barrier Inspections,* established by SLC 16.9.5 provides reasonable assurance that the aging effects will be managed such that fire walls, fire doors, and fire barrier penetration seals will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.16.2 Fire Water System Test

Section 2.5 of OLRP-1001 identifies components in the High Pressure Service Water System, Low Pressure Service Water System and the Service Water System (Keowee) as subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to corrosion and fouling as applicable aging effects. The *Fire Water System Test* manages fouling of the High Pressure Service Water System, Low Pressure Service Water System and Service Water System (Keowee) components falling within the scope of license renewal. This test, in conjunction with the *Service Water Piping Corrosion Program,* the *Galvanic Susceptibility Inspection* and the *Cast Iron Selective Leaching Inspection,* will also serve to manage the loss of material for the components within these systems. The program ensures that these systems remain in compliance with applicable National Fire Protection Association (NFPA) Standards and that the systems meet all applicable Selected Licensee Commitments in Oconee UFSAR Chapter 16. The *Fire Water System Test* has the following attributes. In addition, because it is an existing program, operating experience and demonstration are provided, as applicable.

4.16.2.1 Program Description

Purpose - The purpose of the *Fire Water System Test* is to manage fouling and, in conjunction with several other programs and activities, to manage loss of material for the component locations in the High Pressure Service Water System, Low Pressure Service Water System and the Service Water System (Keowee) that fall within the scope of license renewal.

Scope - The scope of the program credited for license renewal includes the High Pressure Service Water System, Low Pressure Service Water System and Service Water System (Keowee) components serving a regulatory committed fire protection function important to safety and falling within the scope of license renewal.

Aging Effects - The aging effects of concern are fouling of smaller diameter piping such that the system intended function could not be accomplished and loss of material due to a number of corrosion mechanisms, both general and localized, for the bronze, carbon steel, cast iron and stainless steel components exposed to raw water.

Method - This program involves a variety of methods with which to manage the applicable aging effects for the components within these systems. Piping and pumps receive a periodic performance test which demonstrates their ability to perform their component intended functions. Fire hydrants and deluge valves receive a periodic flow test which demonstrates their ability to perform their component intended functions. These tests in particular simulate the actual conditions required for the components to meet the system intended functions. Hose racks and some sprinkler heads receive a visual inspection on a periodic basis.

Sample Size - The components that serve a fire protection function within the High Pressure Service Water System, Low Pressure Service Water System and the Keowee Service Water System are tested or inspected and maintained on a periodic basis.

Industry Codes and Standards - Inspection and testing is conducted in accordance with applicable *National Fire Protection Association Codes* [Reference 4.16-5].

Frequency - Inspection and test frequencies for the components in the High Pressure Service Water System, Low Pressure Service Water System and the Service Water System (Keowee) falling under the scope of the *Fire Water System Test* are established based on the type of component and managed by plant procedures.

Acceptance Criteria - Acceptance criteria are specifically stated in the plant procedures that govern each inspection or test.

Corrective Action - Corrective actions are specifically stated in the plant procedures that govern each inspection or test. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Control - The *Fire Protection Program* is implemented by plant procedures in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - 10 CFR §50.48 [Reference 4.16-1], 10 CFR 50, Appendix R [Reference 4.16-2], Oconee Facility Operating License, License Condition 3.E [Reference 4.16-3], Oconee UFSAR, Chapter 16: Fire Suppression Systems are covered under Selected Licensee Commitment 16.9.1; Sprinkler and Spray systems are covered under Selected Licensee Commitment 16.9.2; and Fire Hose Stations are covered under Selected Licensee Commitment 16.9.4. [Reference 4.16-4].

4.16.2.2 Operating Experience and Demonstration

Fire Protection standards have been in place at Oconee since the original license was issued. The Oconee UFSAR contains General Design Criteria 3, *Fire Protection,* that requires the station to be designed to minimize the probability of events as fires and also to minimize the potential effects of such events to safety [Reference 4.16-6]. The *Fire Water System Test* was enhanced after the cable fire event at Browns Ferry and in response to IE Bulletin 75-04 [Reference 4.16-7]. The program conforms with the standards set forth by the National Fire Protection Association, 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, Low Pressure Service Water System and Keowee Service Water Systems. Full flow testing is comprehensive and includes fire protection systems in the Auxiliary Building, Turbine Building, Reactor Building and the yard loop. Full flow testing has resulted in cleaning due to fouling of approximately 2 sprinkler heads at each of the transformers every 18 months. Fouling of the major header and other sprinklers has not been significant. Approximately one-eighth inch scaling has been noted on a small section of buried 8 inch piping. This minimal amount of degradation has not jeopardized the system's ability to perform its intended function.

Based on the above review, the continued implementation of the *Fire Water System Test* provides reasonable assurance that the aging effects will be managed such that the components of the High Pressure Service Water System, Low Pressure Service Water System and Service Water System (Keowee) will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.16.3 References for Section 4.16

4.16-1. 10 CFR §50.48, *Fire Protection.*

4.16-2. 10 CFR Part 50, Appendix R, *Fire Protection Program for Nuclear Power Facilities Operating Prior to January 1, 1979.*

4.16-3. Oconee Nuclear Station, Units 1, 2, and 3, Facility Operating Licenses DPR-38, DPR-47, and DPR-55.

4.16-4. *Oconee Nuclear Station, Updated Final Safety Analysis,* as revised.

4.16-5. National Fire Protection Association Codes.

4.16-6. Fire Protection Safety Evaluation Report for Oconee Nuclear station, August 11, 1978.

4.16-7. IE Bulletin 75-04, *Cable Fire at Browns Ferry Nuclear Power Station.*

4.17 HEAT EXCHANGER PERFORMANCE TESTING ACTIVITIES

Section 2.5 of OLRP-1001 identifies the heat exchangers subject to aging management review. Section 3.5 of OLRP-1001 identifies fouling due to macro-organisms and silting of smaller diameter piping and tubing, including heat exchanger tubing, in Oconee and Standby Shutdown Facility heat exchangers to be an applicable aging effect requiring management for license renewal. Additionally, in Section 3.5, loss of material in the Standby Shutdown Facility Heating, Ventilation, and Air Conditioning System cooling coil and the SSF HVAC condensers in the Standby Shutdown Facility Auxiliary Service Water System is identified to be an applicable aging effect. As described in the Oconee UFSAR Chapter 13.5.2.2.3, *Periodic Test Procedures*, performance testing is conducted on a periodic basis to determine various station parameters and to verify the continuing capability of safety-related structures, systems and components to meet established performance requirements. Specific *Heat Exchanger Performance Testing Activities* will serve to manage fouling of heat exchanger tubing for those heat exchangers that have heat transfer as a component intended function.

The following heat exchangers in the scope of license renewal have heat transfer as a component intended function that could be impacted by fouling. Each of these heat exchangers has raw water from the Low Pressure Service Water System: the decay heat removal cooler in the Low Pressure Injection System, the Reactor Building cooling units in the Reactor Building Cooling System, and the Standby Shutdown Facility heat exchangers in the Standby Shutdown Facility Auxiliary Service Water and Heating, Ventilation, and Air Conditioning Systems. Performance testing for these heat exchangers will provide assurance that the components are capable of adequate heat transfer required to meet system and accident load demands. Performance testing will also serve to manage loss of material for the applicable Standby Shutdown Facility heat exchangers.

Periodic testing is completed for these heat exchangers at frequencies ranging from twice per day for the Standby Shutdown Facility heat exchangers to each refueling outage for the decay heat removal cooler and the Reactor Building cooling units. Heat removal capacity is determined and compared to test acceptance criteria established by the accountable engineer and to previous test results for the decay heat removal coolers and the Reactor Building cooling units. For the Standby Shutdown Facility heat exchangers, heat removal capacity is verified by monitoring component and system performance parameters and comparing them to acceptance criteria. If the heat exchangers fail to perform adequately, then corrective actions such as cleaning are undertaken. Specific corrective actions are implemented in accordance with the *Duke Quality Assurance Program*.

The *Heat Exchanger Performance Testing Activities* are implemented by plant procedures in accordance with the *Duke Quality Assurance Program*. The activities credited here for license renewal for the Decay Heat Removal Coolers and the Reactor Building Cooling Units are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 4.17-1, 4.17-2, 4.17-3 , 4.17-4, and 4.17-5].

The continued implementation of the *Heat Exchanger Performance Testing Activities* provides reasonable assurance that the heat exchangers will continue to perform their intended function consistent with the current licensing basis for the period of extended operation.

4.17.1 References for Section 4.17

4.17-1. H.B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.17-2. H.B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.17-3. J.W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.17-4. J.W. Hampton (Duke) letter dated September 1, 1994 to the Document Control Desk (NRC), *Follow Up to a Deviation Notice in NRC Inspection Report 93-25 to Revise Response to 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.17-5. J.W. Hampton (Duke) letter dated April 4, 1995 to Document Control Desk (NRC), *Supplemental Response #3 to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.18 INSERVICE INSPECTION PLAN

Throughout the service life of nuclear power plants, Class 1 components and associated supports must meet the requirements set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in §50.55a(b). These requirements are subject to the limitation listed in §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the component or support.

Inservice examinations and system pressure tests conducted during successive 120-month inspection intervals, following the initial 120-month inservice inspection interval, must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in §50.55a(b) twelve months prior to the start of the 120-month inspection interval, subject to the limitations and modifications listed in paragraph §50.55a(b).

As noted in the NRC reviews of BAW-2243A [Reference 4.18-1] and BAW-2244A [Reference 4.18-2], the integrated plant assessment for Reactor Coolant System components within the scope of Subsection IWB of ASME Section XI uses the ASME Boiler & Pressure Vessel Code, 1989 Edition of ASME Section XI, including mandatory Appendices VII and VIII. Appendix VIII is in accordance with the 1989 Addenda.

The period of extended operation for Oconee will contain the 5th and 6th ten-year inservice inspection intervals. The Oconee *Inservice Inspection Plan* for each of these two inservice inspection intervals will:

(1) Include compliance with Appendix VII, *Qualification of Nondestructive Examination Personnel for Ultrasonic Examination*;
(2) Include compliance with Appendix VIII, *Performance Demonstration for Ultrasonic Examination Systems*;
(3) Implement the Subsection IWB examination requirements of either:
    (a) the 1989 Edition of ASME Section XI, or
    (b) the edition of the ASME Section XI Code required by §50.55a(b), 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;
(4) Comply with §50.55a (g)(4)(ii) except that if an examination required by the Code or Addenda is determined to be impractical, then a relief request will be submitted to the Commission in accordance with the requirements contained in §50.55a(5)(iv), for Commission evaluation; and
(5) Include examination of pressurizer heater bundle welds in accordance with Examination B-E (or equivalent) (see Section 4.3.7.2).

4.18.1 ASME Section XI, Subsection IWB and IWC Inspections

Section 2.4 of OLRP-1001 identifies the Reactor Coolant System components subject to aging management review. Section 3.4 of OLRP-1001 identifies cracking, loss of material and loss of closure integrity as applicable aging effects for these components. *ASME Section XI, Subsections IWB and IWC Inspections* under the Oconee *Inservice Inspection Plan* will manage these aging effects for the period of extended operation. The specific Reactor Coolant System component or component feature, applicable aging effect and credited ASME Section XI examination category are identified in Table 3.4-1. The Oconee *Inservice Inspection Plan*, *ASME Section XI, Subsections IWB and IWC Inspections*, has the following attributes.

Purpose - The purpose of *ASME Section XI, Subsection IWB and IWC Inspections* under the scope of the Oconee *Inservice Inspection Plan* is to identify and correct degradation of Oconee Inservice Inspection Class A and Class B pressure retaining components and their integral attachments.

Scope - The scope of the *ASME Section XI, Subsection IWB and IWC Inspections* credited for license renewal is identified specifically for each component and for applicable component features in Table 3.4-1.

Items within the scope of the *ASME Section XI, Subsection IWB and IWC Inspections* may be installed in areas inaccessible for maintenance and inspection. ASME Section XI programmatic oversight does not imply 100% direct coverage of all items within a system, and the Code has made provisions to handle such situations. For those limited instances where inaccessible items requiring inspection do exist, ASME Section XI provides guidance for indirect assurance of component integrity. Indirect assurance comes in the form of approved ASME Code relief, use of statistical sampling methods, and use of indirect symptomatic evidence.

Aging Effects - Cracking, loss of closure integrity, and loss of material by general corrosion or boric acid wastage.

Method - The *ASME Section XI, Subsection IWB and IWC Inspections* under the Oconee *Inservice Inspection Plan* includes examination methods defined in each applicable examination category credited for license renewal. Table 3.4-1 identifies the applicable examination categories.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - ASME Section XI, 1989 Edition, Appendices VII and VIII in accordance with 1989 Addenda.

Frequency - The extent and frequency of inspection are specified in ASME Section XI Tables IWB-2500-1 and IWC-2500-1 for all applicable Examination Categories identified in Table 3.4-1. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria or Standard - The acceptance standards for the examinations that will manage cracking, loss of closure integrity and loss of material are specified in ASME Section XI, Tables IWB-2500-1 and IWC-2500-1 for all applicable Examination Categories identified in Table 3.4-1.

Corrective Action - Components containing relevant conditions as defined in ASME Section XI Subsection IWB-3500 and IWC-3500 shall be evaluated, repaired, or replaced prior to returning to service. Requirements for these actions are specified by ASME Section XI. Specific corrective actions will be implemented in accordance with the Duke *Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee *Inservice Inspection Plan* is implemented by procedures that are developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis -The Oconee *Inservice Inspection Plan* serves to implement the requirements set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in 10 CFR §50.55a(b). These requirements are subject to the limitations listed in 10 CFR §50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the component or support. At present, the code of record for the Oconee units is the 1989 Edition as described in the Oconee Nuclear Station, Third Ten-Year Interval, Inservice Inspection Plan [Reference 4.18-3].

4.18.2 CAST AUSTENITIC STAINLESS STEEL FLAW EVALUATION

Oconee Reactor Coolant System items fabricated from cast austenitic stainless steel (CASS) that are susceptible to reduction of fracture toughness by thermal embrittlement include valve bodies, reactor coolant pump casing and cover, and the outlet nozzle of the Oconee Unit 3 reactor vessel internals. An approach for managing thermal embrittlement of CASS valve bodies was approved by the NRC through the safety evaluation contained in BAW-2243A [Reference 4.18-1]. The approach described in BAW-2243A couples the periodic inservice inspection required through 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 technical basis for use of this evaluation procedure is described in BAW-2243A. While the NRC safety evaluation of the flaw evaluation procedure applied specifically to valve bodies, the procedure may be extended to the reactor coolant pump casing and cover and the outlet nozzle of the Oconee Unit 3 reactor vessel internals, as described below.

4.18.2.1 Reactor Coolant Pump Casing and Cover

The effect of thermal aging embrittlement on CASS reactor coolant pump casing and cover is managed by elements of the Oconee *Inservice Inspection Plan,* which includes the applicable requirements of the ASME Code Section XI, Subsection IWB. Specifically, cracking at welds in pump casings and the integrity of internal, pressure retaining surfaces of pump casings are managed under requirements of Examination Categories B-L-1 and B-L-2, respectively. The examinations are limited to at least one pump in each group of pumps performing similar functions in the system (e.g., recirculating coolant pumps). Examination of the internal pressure boundary is required only when a pump is disassembled for maintenance, repair, or volumetric examination. Examination Categories B-L-1 and B-L-2 will be supplemented by the evaluation procedures for flaws specified in IWB-3640. These procedures formally apply to austenitic piping; however, they may be applied to other RCS items, such as pump casings, as discussed in Section 4.2 of BAW-2243A and EPRI-TR-106092 [Reference 4.18-4].

4.18.2.2 Reactor Vessel Internals

The effect of thermal aging embrittlement of the Oconee Unit 3 cast austenitic stainless steel outlet nozzles is managed by elements of the Oconee *Inservice Inspection Plan,*, which includes the applicable requirements of the ASME Code Section XI, Subsection IWB. Specifically, Examination Category B-N-3 will be supplemented by the evaluation procedures for flaws specified in IWB-3640. These procedures formally apply to austenitic piping; however, they may be applied to other Reactor Coolant System items, such as reactor vessel internals items, as discussed in Section 4.2 of BAW-2243A and EPRI-TR-106092.

4.18.2.3 Summary

In summary, the effects of thermal aging embrittlement of CASS items are found to be managed adequately by the periodic volumetric, surface, and visual inservice inspection program elements specified in the ASME Code Section XI, Subsection IWB. When conditions are detected during these inservice inspections that exceed the allowable limits of ASME Section XI, engineering evaluations of either detected or postulated flaws shall be carried out using material properties and acceptance criteria applicable to the evaluation procedures presented in IWB-3640. More favorable material properties and acceptance criteria may be used, if justified, on a case-by-case basis.

4.18.3 ASME Section XI, Subsection IWF Inspections

Section 2.4 of OLRP-1001 identifies the Reactor Coolant System structural components subject to an aging management review. Section 2.7 identifies the remaining Oconee structural components subject to an aging management review. Section 3.4 of OLRP-1001 identifies cracking of reactor vessel and steam generator support skirt anchorage and loss of material by general corrosion or boric acid wastage as applicable aging effects for Reactor Coolant System structural components. Section 3.7 also identifies loss of material by general corrosion or boric acid wastage as an applicable aging effect for structural components. The Reactor Coolant System structural components and many other structural components fall under the scope of the *ASME Section XI, Subsection IWF Inspections* under the Oconee *Inservice Inspection Plan.* The *ASME Section XI, Subsection IWF Inspections* will manage aging effects on these structural components for the period of extended operation. The specific structural component, applicable aging effect and credited ASME Section XI examination category are identified in Tables 3.4-1, 3.7-1, 3.7-3, 3.7-4, 3.7-5, and 3.7-6. The following program attributes apply to the aging management for these components.

Purpose - The purpose of *ASME Section XI, Subsection IWF Inspections* under the Oconee *Inservice Inspection Plan* is to identify and correct degradation of the structural components within the scope of Subsection IWF.

Scope - The scope of the *ASME Section XI, Subsection IWF Inspections* credited for license renewal is identified specifically for the structural components in Tables 3.4-1, 3.7-1, 3.7-3, 3.7-4, 3.7-5, and 3.7-6. ASME Section XI, Subsection IWF inspections apply to all Class 1, 2, 3, and MC component supports, including exposed surfaces of structural bolting.

Aging Effects - Cracking of reactor vessel and steam generator support skirt anchorage and loss of material by general corrosion or boric acid wastage.

Method - Visual examinations (i.e., VT-3) are conducted to determine the general mechanical and structural condition of component supports within the scope as defined for the applicable component support type in ASME Section XI Table IWF-2500-1.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - ASME Section XI, 1989 Edition, Appendices VII and VIII in accordance with 1989 Addenda.

Frequency - The extent and frequency of inspections are specified in Table IWF-2500-1 for all examination categories credited in Tables 3.4-1, 3.7-1, 3.7-3, 3.7-4, 3.7-5, and 3.7-6. The inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.

Acceptance Criteria - The acceptance standards for the visual examination that will manage cracking and loss of material are specified in ASME Section XI, Subsection IWF-3400.

Corrective Action - In accordance with IWF-3122, supports containing relevant conditions shall be evaluated and tested, or corrected prior to returning to service. Requirements for these actions are specified by ASME Section XI. Specific corrective actions will be implemented in accordance with the Duke *Quality Assurance Program.*
.
Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The Oconee Inservice Inspection Plan is implemented by procedures that are developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - The Oconee *Inservice Inspection Plan* serves to implement the requirements set forth in Section XI of the ASME Code and Addenda that are incorporated by reference in 10 CFR 50.55a(b). These requirements are subject to the limitations listed in 10 CFR 50.55a, to the extent practical within the limitations of design, geometry and materials of construction of the component or support. At present, the Code of record for the Oconee units is the 1989 Edition as described in the Oconee Nuclear Station, Third Ten-Year Interval, Inservice Inspection Plan [Reference 4.18-3].

4.18.4 Operating Experience and Demonstration

ASME Section XI Subsections IWB, IWC, and IWF have been developed by and will continue to be maintained through the consensus process of the ASME Code. The requirements of these subsections, as implemented at Oconee by the Oconee *Inservice Inspection Plan*, are effective in managing the applicable aging effects. The Commission's process of reviewing Editions and Addenda of the ASME Boiler and Pressure Vessel Code, and incorporating them into §50.55a with limitations and modifications as required, provides additional assurance of the effectiveness of this program.

Based on the above review, the continued implementation of the Oconee *Inservice Inspection Plan* provides reasonable assurance that the aging effects will be managed such that the piping and components within the scope of the plan will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.18.5 REFERENCES FOR SECTION 4.18

4.18-1. BAW-2243A, *Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping*, The B&W Owners Group Generic License Renewal Program, June 1996.

4.18-2. BAW-2244A, *Demonstration of the Management of Aging Effects for the Pressurizer*, The B&W Owners Group Generic License Renewal Program, December 1997

4.18-3. H. N. Berkow (NRC) letter dated November 15, 1995 to J. W. Hampton (Duke), *Inservice Inspection Plan for Third Ten-Year Interval, Oconee Nuclear Station, Units 1, 2, and 3,* (TAC Nos. M88484, M888484, and M88486).

4.18-4. EPRI TR-106092, *Evaluation of Thermal Aging Embrittlement for Cast Austenitic Stainless Steel Components in LWR Reactor Coolant Systems, September 1997.*

4.19 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

Section 2.4 of OLRP-1001 identifies the Reactor Coolant System structural components subject to aging management review. Section 2.5 identifies the mechanical components subject to aging management review. Section 2.7 identifies the remaining Oconee structural components subject to aging management review. Section 3.4 of OLRP-1001 identifies loss of material as an applicable aging effect for the Reactor Coolant System 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 environment, sheltered environment, and the 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* will manage these aging effects such that the intended functions of the components will be maintained in accordance with the current licensing basis during the period of extended operation. The *Inspection Program for Civil Engineering Structures and Components* has the following attributes. In addition, because the *Inspection Program for Civil Engineering Structures and Components* is an existing program, operating experience and demonstration are provided, as applicable.

4.19.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Inspection Program for Civil Engineering Structures and Components* is to monitor and assess the condition of structures and components.

Scope - The scope of this program credited for license renewal is identified specifically for the structures and components in Tables 3.4-1, 3.5-1 through 3.5-12, and 3.7-1 through 3.7-8. For license renewal, the program will be enhanced to include any components identified in Tables 3.4-1, 3.5-1 through 3.5-12, and 3.7-1 through 3.7-8 that currently are not identified specifically in the program.

Aging Effects - The *Inspection Program for Civil Engineering Structures and Components* will be utilized 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 environment, sheltered environment, and the yard environment
- Loss of material, cracking, and change of material properties for all other Oconee structural components

Method - Each structure or component is visually inspected from the interior and exterior where accessible. Some components may be inaccessible because of radiological considerations, obstructions or other reasons. Oconee-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. Whenever normally inaccessible areas are made accessible (i.e., by excavation or other means) an inspection is performed and the results are documented as part of the *Inspection Program for Civil Engineering Structures and Components.*

Inspections are performed by a team of at least two people. Inspectors are qualified by appropriate training and experience and approved by responsible Oconee management.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - 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* nominally will be performed every five years, with the exact schedule being established with consideration of refueling outages of each Oconee unit. The interval may be increased to a nominal ten-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 - No unacceptable 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 function and are considered to meet the requirements contained in §50.65(a)(2) of the Maintenance Rule.

Corrective Action - Items which do not meet the acceptance criteria are evaluated by accountable engineer for continued service, monitored, or corrected. 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 using the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Inspection Program for Civil Engineering Structures and Components* is implemented and controlled by the *Duke Quality Assurance Program.*

Regulatory Basis - 10 CFR §50.65, *Requirements for monitoring the effectiveness of maintenance at nuclear power plants* (for those components within the scope of the Maintenance Rule).

4.19.2 Operating Experience and Demonstration

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 Oconee Five Year Civil Inspection. The acceptance criteria and the frequency of the *Inspection Program for Civil Engineering Structures and Components* are considered to be acceptable based on recent Oconee inspection results which 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,* the Oconee Five Year Civil Inspection Program had been used to manage the condition of the structures and structural components which were determined to be important to the safety and operation of the plant. The structures which were previously inspected during the Five Year Civil Inspection were:

- 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 which would adversely affect the ability of the 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.

Based on the above review, 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 the concrete and steel structural components and mechanical components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.20 PENSTOCK INSPECTION

Section 2.7.6 of OLRP-1001 identifies the Keowee Penstock as being subject to aging management review. Section 3.7.6 of OLRP-1001identifies 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* will manage these applicable aging effects for the period of extended operation. The *Penstock Inspection* has the following attributes. In addition, because the *Penstock Inspection* is an existing program, operating experience and demonstration are provided, as applicable.

4.20.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Penstock Inspection* is to ensure that the structural integrity of the Keowee Penstock will be maintained.

Scope - The scope of the *Penstock Inspection* includes both the steel lined and unreinforced concrete lined sections of the Keowee Penstock.

Aging Effects - The applicable aging effects include loss of material, cracking, and change in material properties for the unreinforced concrete lined section and loss of material for the steel lined section of the Keowee Penstock.

Method - The *Penstock Inspection* requires visual examination of the interior surface of the Keowee Penstock.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - No code or standard exists to guide or govern this inspection.

Frequency - Inspections are performed each time the Keowee Penstock is dewatered during outages, which is at least every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as identified by the accountable engineer.

Corrective Action - Areas which 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 Quality Assurance Program*.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - This program is performed in accordance with written guidance developed by the responsible Duke Power department.

Regulatory Basis - 18 CFR Part 12, *Water Power Projects and Project Works Safety*.

4.20.2 Operating Experience and Demonstration

Previous *Penstock Inspections* have revealed only minor degradation of the Keowee Penstock. Observations include minor loss of material of concrete due to abrasion. Other than the degradation noted, the Keowee Penstock was determined to be in good condition.

Based on the above review, the continued implementation of the *Penstock Inspection* provides reasonable assurance that the aging effects will be managed such that the penstock will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

4.21 PIPING EROSION/CORROSION PROGRAM

Section 2.5 of OLRP-1001 identifies components in the Feedwater System and Main Steam System as subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to erosion/corrosion as an applicable aging effect. The *Piping Erosion/Corrosion Program* manages loss of material due to erosion/corrosion for the Feedwater System and portions of the Main Steam System components falling within the scope of license renewal. Overall, the program focuses on the integrity of a number of plant piping systems that are susceptible to erosion/corrosion or flow-accelerated corrosion, as the phenomena is also known. The program is an inspection and analysis program developed to investigate and verify the integrity of piping systems that could be susceptible to erosion/corrosion. The *Piping Erosion/Corrosion Program* establishes piping inspection locations based on an analytical review of the systems falling within its scope. The *Piping Erosion/Corrosion Program* ensures that the loss of material due to erosion/corrosion in the Feedwater System and Main Steam System components will be managed during the period of extended operation.

The *Piping Erosion/Corrosion Program* has the following attributes. In addition, because it is an existing program, operating experience and demonstration are provided, as applicable.

4.21.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Piping Erosion/Corrosion Program* is to manage loss of material for the component locations in the Feedwater System and Main Steam System that have been identified as being susceptible to erosion/corrosion.

Scope - The portion of the overall program credited for license renewal includes the components in the Feedwater System between the main control valves, bypass block valves, and the steam generator, and a small section of piping downstream of the Emergency Feedwater pump turbine steam supply control valve.

Aging Effects - The aging effect of concern is loss of material of carbon steel components due to erosion/corrosion under certain relevant conditions. Relevant conditions include physical parameters such as fluid temperature, fluid (steam) quality, fluid velocity, fluid pH, mechanical component geometry and piping configuration. An analytical review process is used to determine susceptible locations based on these types of relevant conditions.

Method - The focus of the program is on the carbon steel components in the more susceptible locations within these systems. Over seventy total inspection locations exist for the three units' Feedwater Systems and ten separate inspection locations exist for the three units' Main Steam Systems. Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing and radiography. Also visual examination is used when access to interior surfaces is allowed by component design.

Sample Size - No applicable for an existing program.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. However, the program follows the basic guidelines or recommendations provided by EPRI Document NSAC-202L. Component wall thickness acceptability is judged in accordance with the Oconee component design code of record.

Frequency - Inspection frequency varies for each location, depending on previous inspection results, calculated rate of material loss, analytical model review, changes in operating or chemistry conditions, pertinent industry events, and plant operating experiences.

Acceptance Criteria - Using inspection results and including a safety margin, the projected component wall thickness at the time of the next plant outage must be greater than the allowable minimum wall thickness under the component design code of record.

Corrective Action - If the calculated component wall thickness at the time of the next outage is projected to be less than the allowable minimum wall thickness with safety margin under the component design code of record, then the component will be repaired or replaced prior to system start-up. The as-inspected component can also be justified for continued service through additional detailed engineering analysis.

Specific corrective action will be in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - The *Piping Erosion/Corrosion Program* is ongoing and is not a new program for license renewal.

Administrative Control - The *Piping Erosion/Corrosion Program* is implemented by engineering specification in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - Duke response to Bulletin 87-01[References 4.21-1 and 4.21-2] and

Duke response to Generic Letter 89-08 [References 4.21-3 and 4.21-4].

4.21.2 Operating Experience and Demonstration

The *Piping Erosion/Corrosion Program* has been ongoing as a formalized program at Oconee since the early 1980's. The program was originally implemented as a result of several steam leaks at piping elbows caused by loss of material due to erosion/corrosion. These experiences occurred through-out the industry, including at Oconee. The conservative philosophy established within the program has been successful in managing loss of material due to erosion/corrosion. Since the inception of this program, no steam leaks have occurred due to erosion/corrosion in the portions of the systems within the scope of license renewal for which this program is credited. For the portions of the Feedwater System and Main Steam System within the scope of license renewal, susceptible locations have been inspected more than once. For the Feedwater System only one section of piping associated with the Feedwater bypass control valve discharge has required replacement because the projections of piping wall thickness fell below the established acceptance criteria. For the Main Steam System no piping replacements have occurred and no significant loss of material due to erosion/corrosion has been detected.

Based on the above review, the continued implementation of the *Piping Erosion/Corrosion Program* provides reasonable assurance that the aging effects will be managed such that the Main Steam System and Feedwater System components within the scope of license renewal and within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.21.3 Reference for Section 4.21

4.21-1. IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants.*

4.21-2. H. B. Tucker (Duke) letter dated September 14, 1987 to Document Control Desk (NRC), Response to IE Bulletin 87-01, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.21-3. Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

4.21-4. H. B. Tucker (Duke) letter dated July 21, 1989, Response to Generic Letter 89-08, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.22 PROGRAM TO INSPECT THE HIGH PRESSURE INJECTION CONNECTIONS TO THE REACTOR COOLANT SYSTEM

Section 2.4.3 of OLRP-1001 and BAW-2243A [Reference 4.22-1] identify the normal and emergency High Pressure Injection System portions of the Reactor Coolant System branch lines as within the scope of license renewal and subject to aging management review. Section 3.4.3 of OLRP-1001 and BAW-2243A identify loosening of the thermal sleeves or cracking of the thermal sleeves and associated piping welds in the normal and emergency High Pressure Injection (HPI) System portions of the Reactor Coolant System branch lines as applicable aging effects requiring management for license renewal. The *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* describes the methodology for conducting periodic inspections of the portion of the four HPI lines that connect with the Reactor Coolant System. The *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* has the following attributes. In addition, because *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* is an existing program, operating experience and demonstration are provided, as applicable.

4.22.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* is to manage the displacement of the HPI thermal sleeves or cracking of the thermal sleeves and associated piping welds in the normal and emergency HPI portions of the Reactor Coolant System branch lines. This program satisfies the requirements of previous Oconee inspection commitments to the NRC for Generic Letter 85-20 [Reference 4.22-2] and IE Bulletin 88-08 [Reference 4.22-3], as well as some key ASME Section XI requirements and simplifies the programmatic oversight of these risk-significant welds in the Reactor Coolant System.

Scope - The scope of this program includes the HPI nozzles on the reactor coolant loops and attached Reactor Coolant System piping. The program also applies to the thermal sleeves within the nozzles. It encompasses all Oconee System Piping Class A (not ISI Class A) HPI piping and components with the additions of some welds within Oconee System Piping Class B boundaries (still within ISI Class A scope) being examined in accordance with IE Bulletin 88-08 commitments.

Aging Effects - Two aging effects are addressed by this program. The first aging effect is the cracking of the base metal or weld metal which could result in a non-isolable Reactor Coolant System Piping.

The second aging effect is the initiation and growth of gaps between the protective thermal sleeve and the nozzle safe end.

Method - This program includes the inspection techniques for these locations defined from ASME Section XI, Subsection IWB defined in the Oconee *Inservice Inspection Plan*. Additional augmented inspections are done using ultrasonic (UT) and dye-penetrant (PT) inspections of the components of the nozzles and piping to detect cracks, and radiographic (RT) inspections to verify no gaps are growing between the thermal sleeve and the safe end.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - ASME Section XI for the detection and engineering evaluation of flaws in the welds.

Frequency - The frequency of actions under this program are component location-specific. The frequencies are established for each component location by considering the ASME Section XI inspection frequencies in IWB-2400 as well as the frequencies established by Duke regulatory commitments for Generic Letter 85-20 and IE Bulletin 88-08.

Acceptance Criteria or Standard - No flaws in welds and base metal in accordance with ASME Section XI acceptance criteria. No flaws in the nozzle inner radius base metal (which is not required to be inspected under ASME Section XI criteria but which is being inspected under Generic Letter 85-20 commitments) in accordance with standards established as a part of the Duke commitment to Generic Letter 85-20).

No increase in size of the gaps between the thermal sleeve and safe end.

Corrective Action - Flaws in weld or base metal which cannot be accepted based on either the geometry screening or the Fracture Mechanics Analysis methods of ASME Section XI are corrected by repair or replacement activities. Unacceptable gaps detected by sleeve RT are corrected by repair or replacement activities. Specific corrective actions will implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* is implemented by plant procedures and controlled in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Specific Duke-NRC communications with regard to NRC Generic Letter 85-20, IE Bulletin 88-08 and Oconee *Inservice Inspection Plan* provide the regulatory basis for this program. They are*:*

- W. R. McCollum, Jr., (Duke) letter dated August 6, 1997 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, *Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information*.

- W. R. McCollum, Jr., (Duke) letter dated September 10, 1997 to Document control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287, *Inservice Inspection Plan, Third Ten-Year Inservice Inspection Interval, Generic Letter 85-20 Supplemental Information.*

- H. B. Tucker (Duke) letter dated December 29, 1989 to Document Control Desk (NRC), Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, -287, *Thermal Stresses in Piping Connected to Reactor Coolant System (NRC Bulletin 88-08).*

4.22.2 Operating Experience and Demonstration

Oconee has experienced leaking of the Reactor Coolant System as result of aging effects at a specific HPI nozzle location. On April 21, 1997, a leak occurred on Oconee Unit 2. The cause of the leak was a crack in the weld connecting the piping to the nozzle safe-end on one of the two normal HPI injection lines in the HPI system. The root cause was judged to be thermal fatigue. The leak was detected and corrective actions were initiated in accordance with established plant procedures. The incident was reported to the NRC via Licensee Event Report 270/97-01 [Reference 4.22-4]. Following the incident, the location was repaired and inspections on the other nozzle locations were performed. Follow-up investigation by the NRC staff resulted in a Notice of Violation for improper implementation of Duke commitments in response to Generic Letter 85-20 [Reference 4.22-5]. The *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* was subsequently revised in response to this incident.

Based on the above review, the continued implementation of the *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* provides reasonable assurance that the aging effects will be managed such that the high pressure injection nozzles on the reactor coolant loops, attached Reactor Coolant System Piping, and thermal sleeves will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.22.3 References for Section 4.22

4.22-1. BAW-2243A, *Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping*, The B&W Owners Group Generic License Renewal Program, June 1996.

4.22-2. Generic Letter 85-20, *Resolution of Generic Issue 69: High Pressure Injection/Make-up Nozzle Cracking in Babcock and Wilcox Plants.*

4.22-3. IE Bulletin 88-08, *Thermal Stresses in Piping Connected to the Reactor Coolant System.*

4.22-4. J. W. Hampton (Duke) letter dated May 21, 1997 to Document Control Desk (NRC), Licensee Event Report 270/97-01, Revision 0, Oconee Nuclear Station, Unit 3, Docket No. 50-287.

4.22-5. L. A. Reyes (NRC) letter dated August 27, 1997 to W. R. McCollum (Duke), Notice of Violation and Proposed Imposition of Civil Penalties - $330,000 (NRC Inspection Report Nos. 50-269, -270, and -287/97-07 and 50-269, -270, and -287/97-08).

4.23 REACTOR COOLANT SYSTEM OPERATIONAL LEAKAGE MONITORING

Sections 2.4 and 2.5 of OLRP-1001 identify several components within the Reactor Coolant System and High Pressure Injection System whose function is to maintain the system pressure boundary under current licensing basis loading conditions. Sections 3.4 and 3.5 of OLRP-1001 identify the aging effects that are applicable to these components within the Reactor Coolant System High Pressure Injection System that could challenge the integrity of the system pressure boundary. *Reactor Coolant System Operational Leakage*, Oconee Improved Technical Specifications 3.4.13 [Reference 4.23-1], in conjunction with the *Chemistry Control Program*, will manage these aging effects. When the Reactor Coolant System and High Pressure Injection System are in operation, the High pressure Injection System is contiguous with the Reactor Coolant System. The *Reactor Coolant System Operational Leakage Monitoring* has the following attributes. In addition, because *Reactor Coolant System Operational Leakage Monitoring* is an existing program, operating experience and demonstration are provided, as applicable.

4.23.1 PROGRAM DESCRIPTION

Purpose - The purpose of *Reactor Coolant System Operational Leakage Monitoring* is to provide indirect evidence of the condition of components forming the pressure boundary of the Reactor Coolant System to assure that degradation is identified and corrective actions are taken prior to exceeding allowable limits.

Scope - The scope of *Reactor Coolant System Operational Leakage Monitoring* includes all Reactor Coolant System and High Pressure Injection System components that contain coolant.

Aging Effects - The applicable aging effects are cracking, loss of material and loss of closure integrity.

Method - The method of monitoring is specified in Oconee Improved Technical Specification 3.4.13.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - NUREG-1430, *Standard Technical Specifications - Babcock and Wilcox Plants*, Revision 1, April 1995.

Frequency - The frequency of monitoring is specified in Oconee Improved Technical Specification 3.4.13.

Acceptance Criteria or Standard - The acceptance criteria are specified in Oconee Improved Technical Specification 3.4.13.

Corrective Action - The corrective actions are specified in Oconee Improved Technical Specification 3.4.13.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - *Reactor Coolant System Operational Leakage Monitoring* is implemented by written procedures as required by Oconee Improved Technical Specifications 5.4 and the *Duke Quality Assurance Program.*

Regulatory Basis - Oconee Improved Technical Specification 3.4.13, *Reactor Coolant System Operational Leakage*

4.23.2 Operating Experience and Demonstration

A review of Oconee operating experience (i.e., Oconee-specific licensee event reports dating back to 1984) confirms that *Reactor Coolant System Operational Leakage Monitoring* is effective in detecting leakage due to cracking, loss of material, and loss of mechanical closure integrity. Specific examples of cracking, loss of material, or loss of mechanical closure integrity that resulted in Reactor Coolant System leakage in excess of Technical Specification leakage limits include (1) the non-isolable leak at the pressurizer drain line weld in 1998 (LER 269-98002); (2) the non-isolable leak at the weld that connects the HPI branch connection to the safe end in 1997 (LER 270-97001); (3) a once-through steam generator tube leak (LER 287-88002) in 1988; and (4) valve packing failures in 1995 and 1985 that resulted in leakage at bolted closures (LERs 287-95001and 270-85008).

The Bases of Oconee Improved Technical Specifications provides additional evidence that supports the programmatic attributes of Oconee Improved Technical 3.4.13, *Reactor Coolant System Operational Leakage.*

Based on the above review, the continued implementation of the *Reactor Coolant System Operational Leakage Monitoring* program, in conjunction with the *Chemistry Control Program*, provides reasonable assurance that the aging effects will be managed such that the components Reactor Coolant System and the High Pressure Injection System will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.23.3 References for Section 4.23

4.23-1. *Oconee Nuclear Station, Improved Technical Specifications.*

4.24 REACTOR VESSEL INTEGRITY PROGRAM

Section 2.4.5 of OLRP-1001 identifies the reactor vessel as a component that is subject to aging management review for license renewal. Section 3.4.5 of OLRP-1001 identifies reduction in fracture toughness as the applicable aging effect for the period of extended operation for the reactor vessel beltline region. The Oconee *Reactor Vessel Integrity Program* will be utilized to manage this aging effect. The Oconee *Reactor Vessel Integrity Program* consists of the following five interrelated subprograms:

(1) Master Integrated Reactor Vessel Surveillance Program,
(2) Cavity Dosimetry Program,
(3) Fluence and Uncertainty Calculations,
(4) Pressure Temperature Limits, and
(5) Monitoring Effective Full Power Years.

The Master Integrated Reactor Vessel Surveillance Program is an NRC approved B&WOG program [Reference 4.24-1] that complies with requirements for an integrated surveillance program in accordance with §50.60, Appendix H. Cavity dosimetry is used as a continuous monitoring device to ensure that the calculated values of reactor vessel fluence are accurate. Reactor vessel fluence and uncertainty calculations are used as input to calculate pressure temperature limits and end-of-life reference temperatures. Pressure temperature limit curves determine the operating region during normal heatup, normal cooldown, and inservice leak and hydrostatic test transients. The calculation of reactor vessel effective full power years is used to ensure that the pressure temperature limits and end-of-life reference temperatures are not violated.

The acceptability of neutron embrittlement of the Oconee reactor vessels is controlled by NRC Regulations 10 CFR 50.60 and 10 CFR 50.61. NRC Regulation 10 CFR 50.60, “Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation,” requires that all light water nuclear power reactors meet the requirements of Appendix G, “Fracture Toughness Requirements,” and Appendix H, “Reactor Vessel Material Surveillance Program Requirements,” of Part 50. Appendix G specifies fracture toughness requirements for the reactor coolant pressure boundary to provide margins of safety against fracture during any condition of normal plant operation, including anticipated operational occurrences and system hydrostatic tests. NRC Regulation 10 CFR 50.61, “Fracture toughness requirements for protection against pressurized thermal shock,” provides rules for protection against pressurized thermal shock events for pressurized water reactors.

Oconee complies with the requirements of 10 CFR §50.60, Appendices G and H, and 10 CFR §50.61, through the Oconee *Reactor Vessel Integrity Program*, which consists of the five interrelated subprograms discussed above. These subprograms require periodic updates and subsequent NRC review to ensure compliance with 10 CFR §50.60 and 10 CFR §50.61. Continuation of these subprograms will ensure that reduction of fracture toughness of the reactor vessel beltline materials by irradiation embrittlement will be managed during the period of extended operation.

Based on the above discussion and the review that follows, the continued implementation of the *Reactor Vessel Integrity Program* provides reasonable assurance that the aging effects will be managed such that the reactor vessel will continue to perform its intended functions consistent with the current licensing basis for the period of extended operation.

The attributes of these programs are described in Sections 4.24.1 through 4.24.5 that follow.

4.24.1 Master Integrated Reactor Vessel Surveillance Program

Duke is a participant in the B&WOG Master Integrated Reactor Vessel Surveillance Program (MIRVP). The MIRVP meets the requirements of Appendix H of 10 CFR Part 50, with regard to integrated surveillance programs (paragraph III.C) and is also an NRC accepted program. In addition, the MIRVP addresses reference temperature shift concerns and pressurized thermal shock in accordance with §50.61. A description of the MIRVP is provided in BAW-1543A, Revision 2, [Reference 4.24-2] and in BAW 2251 [Reference 4.24-3] The attributes of the MIRVP are provided in the following:

Purpose - The purpose of the MIRVP is to provide a method to monitor reactor pressure vessel materials containing Linde 80 high copper beltline welds for determining the reduction of material toughness by neutron irradiation embrittlement.

Scope - The scope of the MIRVP includes beltline plate and weld material for the beltline region of the Oconee reactor vessels.

Aging Effects - The applicable aging effect is the reduction of material toughness by neutron irradiation embrittlement.

Method - Fracture toughness specimens are irradiated within two operating B&W reactor vessels (i.e., Davis-Besse and Crystal River-3) and the participating Westinghouse reactor vessels. The specimens are irradiated in capsules that are located near the reactor vessel inside wall, thus enabling reactor vessel materials to become irradiated out to and beyond anticipated license renewal fluence levels. The fracture toughness specimens are tested in accordance with applicable ASTM standards as identified in Section 5.0 of BAW-1543A, Revision 2 [Reference 4.24-2].

Sample Size - Not applicable for an existing program.

Industry Code or Standard - ASTM E 185 [Reference 4.24-4]; Regulatory Guide 1.99, Revision 2 [Reference 4.24-5]; ASTM standards as identified in Section 5.0 of BAW-1543A, Revision 2 [Reference 4.24-2], and BAW-1543, Revision 4, Supplement 2 [Reference 4.24-6];

Frequency - The capsule withdrawal schedules are presented in BAW-1543, Revision 4, Supplement 2 [Reference 4.24-6]. The MIRVP schedule may be altered due to unscheduled downtimes or extended outages at the host plants. In addition, certain surveillance capsules may receive additional irradiation to fully satisfy license renewal fluence requirements.

Acceptance Criteria or Standard - Fracture toughness specimens removed from the surveillance capsules will be laboratory tested to ensure reactor vessel fracture toughness properties exhibit upper shelf energy greater than 50 ft-lbs. If the Charpy upper-shelf energy drops below 50 ft-lbs, then it must be demonstrated that margins of safety against fracture are equivalent to those of Appendix G of ASME Section XI. In addition, calculations of reference temperature for pressurized thermal shock (RT_{PTS}) must be below the screening criteria of 270°F for plates, forgings, and longitudinal welds and 300°F for circumferential welds, respectively. If the projected reference temperature exceeds the screening criteria, licensees are required to submit an analysis and schedule for such flux reduction programs as are reasonably practicable to avoid exceeding the screening criteria. If no reasonably practicable flux reduction program will avoid exceeding the screening criteria, licensees shall submit a safety analysis to determine what actions are necessary to prevent potential failure of the reactor vessel if continued operation beyond the screening criteria is allowed.

Corrective Action - Not applicable because this program is collecting irradiated materials data.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - Fracture toughness specimens are being tested and analyzed using procedures and specifications developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - §50.60, *Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation*; §50.61, *Fracture Toughness requirements for protection against pressurized thermal shock*; Appendix G to Part 50, *Fracture Toughness Requirements*; Appendix H to Part 50, *Reactor Vessel Material Surveillance Program Requirements*; and Oconee Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

4.24.2 Cavity Dosimetry Program

The *Cavity Dosimetry Program* is an Oconee on-site method to continuously monitor the reactor vessel beltline region fluence for determining the reduction of material toughness due to neutron irradiation embrittlement.

Purpose - The purpose of the *Cavity Dosimetry Program* is to provide an improved methodology to more accurately estimate reactor vessel accumulated neutron fluence for the reactor vessel limiting beltline welds. Cavity dosimetry measurements are used to verify the accuracy of fluence calculations and to determine fluence uncertainty values.

Scope - All three Oconee reactor vessels are included in the cavity dosimetry program; however, only the Oconee Unit 2 reactor vessel has installed cavity dosimetry. The Oconee Unit 1 and Oconee Unit 3 reactor vessel fluence uncertainty values are based on Oconee Unit 2 cavity dosimetry results due to similar design, fabrication, operation, and fuel loading patterns.

Aging Effects - The reduction of material toughness by irradiation embrittlement.

Method - Dosimeters (i.e., U_{238}, Np_{237}, Ni, Cu, etc.) are irradiated in the cavity region outside of the Oconee Unit 2 reactor vessel. Cavity dosimetry was irradiated at Oconee Unit 2 for cycle 9, cycle 10, combined cycles 11-12, combined cycles 13-14, and combined cycles 15-16. At present, cavity dosimetry is being irradiated at Oconee Unit 2 for combined cycles 17-18.

The cavity dosimeters are measured to determine the activity resulting from the fast fluence irradiation. In addition, calculations of the dosimetry activities are performed using operational data. The calculations are compared to the measurements to verify the accuracy and the uncertainty in the calculated fluence.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - Regulatory Guide 1.99, Revision 2 [Reference 4.24-5]; ASTM E 185 [Reference 4.24-4]; Draft Regulatory Guide - 1053 [Reference 4.24-7]; BAW-2241P [Reference 4.24-8].

Frequency - At present, cavity dosimetry is changed out on an every-other-cycle basis. Future trends indicate extending the frequency to an every-third-cycle exchange period or longer. The cavity dosimetry exchange schedule may be altered due to changes in fuel type, fuel loading pattern, or power rating of Oconee Unit 2.

Acceptance Criteria or Standard - Dosimetry removed from the cavity dosimetry holder is laboratory tested to count the amount of neutron irradiation damage to the dosimetry specimens. Computer analyses are used to calculate the dosimeter activities and associated fluence. Following computer analyses, the calculated accumulated fast fluence will be determined. The results of the fluence uncertainty values should be within the NRC-suggested limit of ±20%.

Corrective Action - As additional cavity dosimetry is withdrawn and tested, cavity dosimetry exchange frequency may be adjusted, as appropriate. If the comparison of calculations to measurements of the Unit 2 multiple dosimeters fail to meet +20 %, measurements and calculations will be reviewed to locate the discrepancy.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - Cavity dosimetry is being tested and analyzed using procedures and specifications developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - §50.60, *Acceptance criteria for fracture prevention measures for lightwater nuclear power reactors for normal operation*; Appendix H to Part 50, *Reactor Vessel Material Surveillance Program Requirements*; and Oconee Improved Technical Specification 3.4.3, Reactor Coolant System Pressure and Temperature (P/T) Limits.

4.24.3 FLUENCE AND UNCERTAINTY CALCULATIONS

The reactor vessel *Fluence And Uncertainty Calculations* are used as inputs to the pressure temperature limit curves and pressurized thermal shock calculations. Updating fluence and uncertainty calculations is essential to maintaining an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value.

Purpose - The purpose of the reactor vessel *Fluence And Uncertainty Calculations* is to provide an accurate prediction of the actual reactor vessel accumulated neutron fast fluence value.

Scope - The *Fluence And Uncertainty Calculations* includes all three of the Oconee reactor vessels.

Aging Effect - The reduction of material toughness by neutron irradiation embrittlement.

Method - The cavity dosimetry program yields irradiated dosimeters that are analyzed based on Oconee specific geometry models (i.e., Mark-B8 fuel, reactor vessel, capsule holder, concrete structures), macroscopic cross sections, cycle-specific sources using the DORT and GIP computer codes, and a reference set of microscopic cross sections (BUGLE-93). Specific attention is made to target fluence values for limiting reactor vessel beltline circumferential weld locations. Recently updated fluence and uncertainty calculations were based on cavity dosimetry irradiated at Oconee Unit 2 for cycle 9, cycle 10, combined cycles 11-12, and combined cycles 13 - 14. Future revised calculations will be based on cavity dosimetry currently being irradiated at Oconee Unit 2 for combined cycles 15-16.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - Regulatory Guide 1.99, Revision 2 [Reference 4.24-5]; ASTM E 185 [Reference 4.24-4; Draft RG-1053 [Reference 4.24-7], BAW-2241P [Reference 4.24-8].

Frequency - Fluence and uncertainty calculations are expected to follow each cavity dosimetry analysis for the next few years. The frequency of updating fluence and uncertainty calculations may change as additional data are obtained. Future decisions concerning the frequency of withdrawal of dosimetry will be based on changes in fuel type or fuel loading pattern.

Acceptance Criteria or Standard - The results of the fluence uncertainty values are to be within the NRC-suggested limit of $\pm$20%. Calculated fluence values for fluence levels above 1.0MeV are compared with measurement values to determine if calculations contain any errors. This methodology represents a continuous validation process to ensure that no biases have been introduced, and that the uncertainties remain comparable to the reference benchmarks.

Corrective Action - As additional cavity dosimetry is withdrawn and tested, fluence and uncertainty calculations will be revised and updated accordingly. If comparisons of dosimetry calculations to measurements are not within acceptance standards, then the calculations will be revised. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Fluence And Uncertainty Calculations* are developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Appendix H to Part 50, *Reactor Vessel Material Surveillance Program Requirements*; and Oconee Improved Technical Specification 3.4.3, *Reactor Coolant System Pressure and Temperature (P/T) Limits.*

4.24.4 PRESSURE TEMPERATURE LIMIT CURVES

Pressure Temperature Limit Curves determine the operating region during normal heatup, normal cooldown, and inservice leak and hydrostatic test transients. Periodically they are updated based on revised accumulated fluence values, additional effective full power years, and to incorporate methodology or regulatory changes.

Purpose - The purpose of the *Pressure Temperature Limit Curves* is to establish the normal operating limits for the Reactor Coolant System.

Scope - The scope of the *Pressure Temperature Limit Curves* includes all three of the Oconee reactor vessels.

Aging Effects - The reduction of material toughness by neutron irradiation embrittlement.

Method - Pressure temperature curves are generated assuming a postulated 1/4T surface flaw in accordance with ASME Section XI, Appendix G [Reference 4.24-9]. Bounding input heatup and cooldown transients are used to develop the pressure temperature curves. Current Oconee Unit-1, -2, and -3 *Pressure Temperature Limit Curves* are valid for 21, 19, and 21 EFPY, respectively. In 1998, updated Oconee *Pressure Temperature Limit Curves* are being extended to at least 26 EFPY for all three units.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - ASME Section XI, Appendix G, 1989 Edition [Reference 4.24-9]; ASME Code Case N-514 [Reference 4.24-10]; Regulatory Guide 1.99, Revision 2 [Reference 4.24-5].

Frequency - *Pressure Temperature Limit Curves* are valid for a period of time expressed in Effective Full Power Years (EFPY). The curves are required to be updated prior to exceeding this time period.

Acceptance Criteria or Standard - NRC approved *Pressure Temperature Limit Curves* must be in place for continued plant operation.

Corrective Action - Oconee Improved Technical Specifications, *ITS 3.4.3, RCS Pressure and Temperature (P/T) Limits*, require valid pressure-temperature limits prior to and during plant operations. Actions to be taken if the pressure-temperature limits are not valid are specified in Oconee Improved Technical Specifications 3.4.3.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *RCS Pressure and Temperature (P/T) Limits.* are developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Oconee Improved Technical Specification ITS 3.4.3, *Reactor Coolant System Pressure and Temperature (P/T) Limits.*

4.24.5 EFFECTIVE FULL POWER YEARS

Effective Full Power Years provide a measurement of the age of the reactor vessel and is required input for verifying pressure temperature limit curves and pressurized thermal shock validity periods. The values for *Effective Full Power Years* are established from the calculation of Effective Full Power Hours and Effective Full Power Days.

Purpose - The purpose *Effective Full Power Years* is to accurately monitor and tabulate the accumulated operating time and cycles experienced by the reactor vessel and other Reactor Coolant System components.

Scope - The scope of the *Effective Full Power Years* activity includes all three of the Oconee reactor vessels.

Aging Effect - The reduction of material toughness by neutron irradiation embrittlement.

Method - The effective full power days of plant operation are based on reactor vessel incore power readings. The Nuclear Applications Software, which runs on the operator aid computer, collects incore instrument data. Site reactor engineers determine effective full power days values by comparing the burnup to the thermal power calculated burnup. All data is collected continuously for all three Oconee units.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - None.

Frequency - Each unit is continuously computer monitored and updated weekly by site reactor engineers to determine the effective full power days of Reactor Coolant System operation during the previous seven day period.

Acceptance Criteria or Standard - For a given fuel cycle, the updated effective full power days calculation based on the power history must be within ± 0.25 EFPD of the operator aid computer generated value.

Corrective Action - As additional effective full power hour and effective full power day values become available, effective full power year calculations are revised and updated accordingly. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Effective Full Power Years* activity are implemented by Oconee workplace procedures developed and maintained in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - Oconee Improved Technical Specification 3.4.3, *Reactor Coolant System Pressure and Temperature (P/T) Limits.*

4.24.6 References for Section 4.24

4.24-1. D. B. Matthews (NRC) letter dated July 11, 1997 to J. H. Taylor (FTI), Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group Report BAW-1543, Revision 4, Supplement 2, *Supplement to the Master Integrated Reactor Vessel Surveillance Program*, TAC No. M98089.

4.24-2. BAW-1543A, Revision 2, *Integrated Reactor Vessel Surveillance Program,* B&W Owners Group Materials Committee, May 1985.

4.24-3. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel*, The B&W Owners Group Generic License Renewal Program, June 1996.

4.24-4. ASTM E 185, *Standard Practice for Conducting Surveillance Test for Light-Water Cooled Nuclear Power Reactor Vessels.*

4.24-5. Regulatory Guide 1.99, Revision 2, NRC, *Radiation Embrittlement of Reactor Vessel Material, May 1998.*

4.24-6. BAW-1543, Revision 4, Supplement 2, *Supplement to the Master Integrated Reactor Vessel Surveillance Program,* Babcock & Wilcox Owners Group (B&WOG) Reactor Vessel Working Group.

4.24-7. Draft Regulatory Guide - 1053, *Calculational and Dosimetry Method for Determining Pressure Vessel Neutron Fluence,* June 1996.

4.24-8. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June 1998).

4.24-9. ASME Section XI, Appendix G for Nuclear Power Plants, Division 1, *Protection Against Non-Ductile Failure.*

4.24-10. ASME Code Case N-514, *Low Temperature Overpressure Protection,* Section XI, Division 1.

4.25 SERVICE WATER PIPING CORROSION PROGRAM

Section 2.5 of OLRP-1001 identifies components in the Auxiliary Service Water System, the Condenser Circulating Water System, the High Pressure Service Water System, the Low Pressure Injection System (for the raw water side of the Decay Heat Cooler), the Low Pressure Service Water System, the SSF Auxiliary Service Water System, the Keowee Service Water System, the Turbine Generator Cooling Water System, and the Turbine Sump Pump System as subject to aging management review. Section 3.5 of OLRP-1001 identifies loss of material due to corrosion as an applicable aging effect. The *Service Water Piping Corrosion Program* will manage loss of material due to general corrosion of brass, bronze, carbon steel and cast iron components in the Oconee raw water systems. The program also will serve to manage loss of material due to pitting corrosion and microbiologically-influenced corrosion (MIC) in bronze, carbon steel, cast iron, and stainless steel components. The program is an inspection and analysis program developed to investigate and verify the integrity of the service water piping systems that could be susceptible to loss of material due to general and localized corrosion. The *Service Water Piping Corrosion Program* establishes piping inspection locations based on engineering guidance, industry guidance, and operating experience.

The *Service Water Piping Corrosion Program* has the following attributes. In addition, because it is an existing program, operating experience and demonstration are provided, as applicable.

4.25.1 PROGRAM DESCRIPTION

Purpose - The *Service Water Piping Corrosion Program* will manage loss of material due to general and localized corrosion for components in the Auxiliary Service Water System, the Condenser Circulating Water System, the High Pressure Service Water System, the Low Pressure Injection System (for the raw water side of the Decay Heat Cooler), the Low Pressure Service Water System, the SSF Auxiliary Service Water System, the Keowee Service Water System, the Turbine Generator Cooling Water System, and the Turbine Sump Pump System.

Scope - The scope of the program credited for license renewal includes all bronze, carbon steel, cast iron and stainless steel components in the license renewal portions of the systems listed in the Purpose. The program focuses on the carbon steel piping components exposed to raw water which are more susceptible to general corrosion and which serve as a leading indicator of the general material condition of the system components. At the time of the Application, no inspection locations were identified for any of the Keowee systems since they remain bounded by the overall program results.

For license renewal, the program will be enhanced to include piping inspection locations at Keowee, focused on bronze and brass piping.

Over 30 different carbon steel piping component inspection locations have been established throughout the applicable systems based on the understanding that fluid flow rates are a prime contributor to the conditions conducive to corrosion. Inspection locations are spread among the four flow regimes: (1) stagnant, (2) intermittent, (3) low flow or approximately three feet per second or less, and (4) normal flow or flow greater than three feet per second based on system operations.

Aging Effects - The aging effects of concern are loss of material due to general corrosion of bronze, carbon steel, and cast iron components and loss of material due to localized corrosion for bronze, carbon steel, cast iron and stainless steel that may reveal itself in the raw water systems within the scope of license renewal.

Method - Inspection methods for susceptible component locations include use of volumetric examinations using ultrasonic testing. Also, visual examination is used as a general characterization tool in conjunction with ultrasonic testing when access to interior surfaces is allowed such as during plant modifications.

Sample Size - Not applicable for an existing program.

Industry Codes and Standards - No code or standard exists to guide or govern this inspection. However, the program follows the basic guidelines or recommendations provided by EPRI Document NSAC-202L. Component wall thickness acceptability is judged in accordance with the component design code of record.

Frequency - Because the corrosion phenomena is slow-acting, inspection frequency varies for each location with a periodicity on the order of five to ten years. The first inspections were performed in the early 1990s. The frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events and plant operating experiences. Most locations received one re-inspection at the time of application.

Acceptance Criteria - No inspection locations falling below the minimum pipe wall thickness values for the inspection locations as defined in the program. These minimum values have been determined based on design pressure or structural loading using the piping design code of record and then applying additional conservatism.

Corrective Action - Inspection locations that fall below the acceptance criteria are repaired or replaced prior to the system returning to service unless an engineering analysis allows further operation. In the cases where a component may be allowed to continue in service, a re-inspection interval is established in the program.

Specific corrective actions will implemented in accordance with the *Duke Quality Assurance Program*.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Control - The *Service Water Piping Corrosion Program* is implemented by engineering specification in accordance with the *Duke Quality Assurance Program*.

Regulatory Basis - The *Service Water Piping Corrosion Program* is a formalization of a portion of the commitments made in response to GL 89-13, primarily those associated with component pressure boundary maintenance [References 4.25-1, 4.25-2, 4.25-3, 4.25-4, and 4.25-5].

4.25.2 Operating Experience and Demonstration

The *Service Water Piping Corrosion Program* was formalized in 1993. The program began in the 1980s with an engineering study aimed at understanding how loss of material due to general corrosion could be affecting the Oconee raw water system piping. The early investigation was continued as a part of Oconee efforts to address GL 89-13. The first sets of piping wall thickness data were taken in 1990. The results of the data showed minimal to no wall loss at all inspection locations. These initial results confirmed the slow-acting nature of the corrosion phenomenon as these components had then been in service approximately 20 years. Since then additional inspections have continued to confirm the sound condition of the piping components. No piping replacements in any system have been necessary based on the results of the piping inspections under the *Service Water Piping Corrosion Program*.

Based on the above review, the continued implementation of the *Service Water Piping Corrosion Program* provides reasonable assurance that the aging effects will be managed such that the components of the Auxiliary Service Water System, the Condenser Circulating Water System, the High Pressure Service Water System, the Low Pressure Injection System (for the raw water side of the Decay Heat Cooler), the Low Pressure Service Water System, the SSF Auxiliary Service Water System, the Keowee Service Water System, the Turbine Generator Cooling Water System, and the Turbine Sump Pump System will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.25.3 References for Section 4.25

4.25-1. H.B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.25-2. H.B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment,* Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.25-3. J.W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.25-4. J.W. Hampton (Duke) letter dated September 1, 1994 to the Document Control Desk (NRC), *Follow Up to a Deviation Notice in NRC Inspection Report 93-25 to Revise Response to 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.25-5. J.W. Hampton (Duke) letter dated April 4, 1995 to Document Control Desk (NRC), *Supplemental Response #3 to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.26 STEAM GENERATOR TUBE SURVEILLANCE PROGRAM

Section 2.4.7 of OLRP-1001 identifies the once through steam generators as subject to aging management review. Section 3.4.7 of OLRP-1001 identifies the aging effects that are applicable to the once through steam generators during the period of extended operation. The *Steam Generator Tube Surveillance Program*, Oconee Improved Technical Specification 5.5.10 [Reference 4.26-1], in conjunction with the *RCS Operational Leakage Monitoring* (see Section 4.23), *Inservice Inspection Plan* (see Section 4.18), and *Chemistry Control Program* (see Section 4.6) will manage these aging effects. The *Steam Generator Tube Surveillance Program* has the following attributes. In addition, because *Steam Generator Tube Surveillance Program* is an existing program, operating experience and demonstration are provided, as applicable.

4.26.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Steam Generator Tube Surveillance Program* is to provide comprehensive examinations of the steam generator tubes to assure that degradation of the tubes is identified and corrective actions are taken prior to exceeding allowable limits.

Scope - The scope of the *Steam Generator Tube Surveillance Program* includes all steam generator tubes in each steam generator.

Aging Effects or Relevant Conditions - The aging effects managed by the *Steam Generator Tube Surveillance Program* are: loss of material, cracking, and mechanical distortion of the tubing.

Method - The method of examination is specified in Oconee Improved Technical Specification 5.5.10.

Sample Size - Not applicable for an existing program.

Industry Codes or Standards - NUREG-1430, *Standard Technical Specifications - Babcock and Wilcox Plants*, Revision 1, April 1995;

Frequency - The frequency of examination is specified in Oconee Improved Technical Specification 5.5.10.

Acceptance Criteria or Standard - Acceptance criteria are specified in Oconee Improved Technical Specification 5.5.10.

Corrective Action - The corrective actions are specified in Oconee Improved Technical Specification 5.5.10.

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Steam Generator Tube Surveillance Program* is implemented by written procedures as required by Oconee Improved Technical Specification 5.4 and the *Duke Quality Assurance Program.*

Regulatory Basis - Oconee Improved Technical Specification 5.5.10 *Steam Generator (SG) Tube Surveillance Program*

4.26.2 Operating Experience and Demonstration

A review of Oconee operating experience confirms that the Steam Generator Tube Surveillance Program is effective in managing cracking, loss of material, and denting of tubes. Routine, non-destructive examinations (mainly eddy current testing) of a representative number of steam generator tubes have been performed at each unit's refueling outages. Several examinations have been performed during non-scheduled outages for various reasons. The non-destructive in-service examinations (eddy current testing) have been expanded and enhanced during operating life to inspect additional tubes above the technical specification requirements. Enhancements include utilizing new and improved technology to detect and characterize tube degradation at lower levels. Identified problems and indications have either been repaired by plugging or sleeving the affected tubes, or have been identified and tracked to monitor any further degradation. Periodically, tubes have been removed from the steam generators and examined with both non-destructive and destructive techniques in the laboratory to verify and validate the in-service non-destructive examination methods.

The Bases of Oconee Improved Technical Specifications provide evidence that supports the programmatic attributes of ITS 5.5.10 *Steam Generator (SG) Tube Surveillance Program.*

Based on the above review, the continued implementation of the *Steam Generator (SG) Tube Surveillance Program* provides reasonable assurance that the aging effects will be managed such that the steam generators will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.26.3 References for Section 4.26

4.26-1. *Oconee Nuclear Station Improved Technical Specifications*

4.27 SYSTEM PERFORMANCE TESTING ACTIVITIES

Section 2.5 of OLRP-1001 identifies mechanical components in Oconee, Keowee, and Standby Shutdown Facility systems that are subject to aging management review. Section 3.5.3 of OLRP-1001 identifies fouling due to macro-organisms and silting in Oconee, Keowee, and Standby Shutdown Facility raw water systems to be an applicable aging effect for smaller diameter piping that requires management for license renewal. Additionally in Section 3.5.14, loss of material in the Standby Shutdown Facility Auxiliary Service Water System air ejector and orifices is identified to be an applicable aging effect. As described in the Oconee UFSAR Chapter 13.5.2.2.3, *Periodic Test Procedures*, performance testing is conducted on a periodic basis to determine various station parameters and to verify the continuing capability of safety-related structures, systems and components to meet established performance requirements. Complete, integrated system performance tests are performed to the extent possible, based on the system design. Where integrated system performance tests are not possible, hydraulic models are usually used to complement the results gained from partial system testing. Even visual inspection of the interior of piping systems can be a complementary activity under the system performance test. Specific *System Performance Testing Activities* will serve to manage fouling.

The following raw water systems have been identified as containing smaller diameter piping that could be effected by fouling and will be managed by *System Performance Testing Activities*: Auxiliary Service Water System, Low Pressure Service Water System, SSF Auxiliary Service Water System, Turbine Generator Cooling Water System, and Turbine Sump Pump System. Performance testing for these systems will provide assurance that the components are capable of delivering adequate flow at a sufficient pressure as required to meet system and accident load demands. Performance testing will also provide the means to manage the loss of material in the Standby Shutdown Facility Auxiliary Service Water System air ejector and orifices as loss of material will be directly revealed by system performance.

Periodic testing and inspections are completed for the above systems at a range of frequencies. Periodic testing frequencies range from quarterly to every third refueling outage, depending on the system. The Turbine Generator Cooling Water System is tested at design conditions every time the Keowee units operate. The Keowee units operate at about a ten percent capacity factor. Visual inspections of the Auxiliary Service Water System are conducted every five years.

Flow capacity is determined and compared to test acceptance criteria established by engineering and to previous test results. The results of visual inspections are evaluated by engineering. If the results of the flow tests and inspections do not meet acceptance criteria, then corrective actions, which could require piping replacement, are undertaken. Specific corrective actions are implemented in accordance with the *Duke Quality Assurance Program*.

The *System Performance Testing Activities* are implemented by plant procedures in accordance with the *Duke Quality Assurance Program*. The activities credited here for license renewal are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 4.27-1, 4.27-2, 4.27-3 , 4.27-4, and 4.27-5].

The continued implementation of the *System Performance Testing Activities* provides reasonable assurance that the aging effects will be managed such that mechanical components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.27.1 References for Section 4.27

4.27-1. H.B. Tucker (Duke) letter dated January 26, 1990 to the Document Control Desk (NRC), *Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.27-2. H.B. Tucker (Duke) letter dated May 31, 1990 to the Document Control Desk (NRC), *Supplemental Response to NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.27-3. J.W. Hampton (Duke) letter dated December 10, 1992 to the Document Control Desk (NRC), *Confirmation of Implementation of Recommended Action Related to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.27-4. J.W. Hampton (Duke) letter dated September 1, 1994 to the Document Control Desk (NRC), *Follow Up to a Deviation Notice in NRC Inspection Report 93-25 to Revise Response to 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.27-5. J.W. Hampton (Duke) letter dated April 4, 1995 to Document Control Desk (NRC), *Supplemental Response #3 to Generic Letter 89-13*, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

4.28 TENDON - SECONDARY SHIELD WALL - SURVEILLANCE PROGRAM

Section 2.7.7 of OLRP-1001 identifies the Secondary Shield Wall Post-Tensioning System as subject to aging management review. Section 3.7.7 of OLRP-1001 identifies the aging effects that are applicable to the Secondary Shield Wall Post-Tensioning System during the period of extended operation. The *Tendon - Secondary Shield Wall - Surveillance Program* will manage these aging effects. The *Tendon - Secondary Shield Wall - Surveillance Program* has the following attributes. In addition, because the *Tendon - Secondary Shield Wall - Surveillance Program* is an existing program, operating experience and demonstration are provided, as applicable.

4.28.1 PROGRAM DESCRIPTION

Purpose - The purpose of the *Tendon - Secondary Shield Wall - Surveillance Program* is to inspect the Secondary Shield Wall Post-Tension Tendon System to ensure that the quality and structural performance of the secondary shield wall is consistent with the licensing basis.

Scope - The scope of this program includes the tendon wires and tendon anchorage hardware, including bearing plates, anchorheads, bushing, buttonheads, and shims of the Units 1, 2, and 3 Secondary Shield Wall Tendons.

Aging Effects - The applicable aging effects include loss of material due to corrosion and cracking of tendon anchorage; wire force relaxation; loss of material due to corrosion and breakage of wires; loss of material due to corrosion and cracking of bearing plate; cracked, split, and broken buttonheads; cracking and loss of material due to corrosion of shims.

Method - This program requires a visual examination of in-scope components and lift-off testing of the tendon system.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - No code or standard exists to guide or govern this program.

Frequency - All vertical tendon caps are visually inspected each refueling outage. A random sample of tendons (including vertical) are inspected every other refueling outage and lift-off tests are performed on a selected number of tendons. All accessible tendon anchorages are visually inspected every fourth refueling outage. The inspection sample size and the frequency of performance of the inspections were initially based on the judgment of experienced engineers. The frequency and extent of the inspections are acceptable because they are more stringent than those used for reactor building containment tendon inspections required by ASME, Section XI, Subsection IWL which has been endorsed by the NRC.

Acceptance Criteria or Standard - No unacceptable visual indication of moisture, discoloration, foreign matter, rust, corrosion, splits or cracks in the buttonheads, broken or missing wires, and other obvious damage as identified by the accountable engineer. Lift-off forces are measured and compared to established acceptance criteria. Oconee operating experience tends to confirm that visual inspections and lift-off tests of these tendons are appropriate.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. Specific corrective actions are implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *Tendon - Secondary Shield Wall - Surveillance Program* is implemented by written procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis - This program has no current regulatory basis.

4.28.2 Operating Experience and Demonstration

The *Tendon - Secondary Shield Wall - Surveillance Program* was implemented in 1982 in response to the finding of tendon corrosion. On April 28, 1982, during the final Reactor Building interior inspection on Unit 2, one secondary shield wall vertical tendon was found broken. Subsequent detailed inspection of the Units 1, 2, and 3 Secondary Shield walls found one additional failed vertical tendon in Unit 2, no failures in Units 1 and 3, and some vertical tendons exhibiting corrosion in Units 1, 2 and 3. All rejected tendons were replaced. The apparent cause of the corrosion was water accumulation in the bottom of the vertical tendon sheath.

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 lower portion of the tendon sheaths.

Modifications were made to prevent the build up of water in the tendon sheaths. In addition to the modifications, a surveillance program was designed to ensure that any future corrosion is detected, evaluated and corrective action is taken to minimize additional deterioration. The NRC was notified that the surveillance program was implemented to assure that any future corrosion is detected and corrective action is taken to prevent tendon failure [Reference 4.28-1]. The 1982 incident was also documented in Reportable Occurrence Report RO-270/82-07, Revision 1 [Reference 4.28-2].

More than twenty inspections have been performed on the Secondary Shield Wall tendons. The secondary shield wall inspections have revealed wire corrosion and surface corrosion of the anchorage hardware. Water has been detected in some end caps and they have been modified to provide drainage. Where tendon lift-off readings have fallen below the minimum allowable, adjacent tendons were tested and the tendons have been re-tensioned.

Based on the above review, the continued implementation of the *Tendon - Secondary Shield Wall - Surveillance Program* provides reasonable assurance that the aging effects will be managed such that the secondary shield wall tendons will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.28.3 References for Section 4.28

4.28-1. W. O. Parker (Duke) letter dated May 12, 1982 to J. P. O’Reilly (NRC), Docket No. 50-270.

4.28-2. H. B. Tucker (Duke) letter dated July 27, 1983 to J. P. O’Reilly (NRC), Docket No. 50-270.

4.29 230 kV Keowee Transmission Line Inspection

Section 2.7.10 of OLRP-1001 identifies the 230 kV Keowee transmission line towers as subject to aging management review. Section 3.7.10 of OLRP-1001 identifies 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 *230 kV Keowee Transmission Line Inspection* will manage this aging effect. The *230 kV Keowee Transmission Line Inspection* has the following attributes. In addition, because the *230 kV Keowee Transmission Line Inspection* is an existing program, operating experience and demonstration are provided, as applicable.

4.29.1 Program Description

Purpose - The purpose of the *230 kV Keowee Transmission Line Inspection* is to maintain the structural integrity of the 230 kV Keowee transmission line structures.

Scope - The *230 kV Keowee Transmission Line Inspection* include steel towers, concrete foundations, and hardware within the 230 kV Keowee transmission line.

Aging Effects - The applicable aging effects of concern include loss of material due to corrosion of the steel structures and loss of material due to spalling or scaling for concrete components.

Method - The inspection requires a visual examination of the towers.

Sample Size - Not applicable for an existing program.

Industry Code or Standard - National Electric Safety Code, Part 2 *Safety Rules for Overhead Lines*; Rule 214 *Inspection and Tests of Lines and Equipment.*

Frequency - The inspections are performed once every five years.

Acceptance Criteria or Standard - No unacceptable visual indication of aging effects as evaluated by the inspector.

Corrective Action - Areas which 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 Quality Assurance Program.*

Timing of New Program or Activity - Not applicable for an existing program.

Administrative Controls - The *230 kV Keowee Transmission Line Inspection* is contracted through the Oconee site engineering group with Duke Power's Power Delivery Group. The inspection is addressed within the Oconee preventive maintenance program.

Regulatory Basis - National Electric Safety Code, Part 2, *Safety Rules for Overhead Lines*, Rule 214 *Inspection and Tests of Lines and Equipment.*

4.29.2 Operating Experience and Demonstration

Visual inspections of the 230 kV Keowee transmission line, including the towers and hardware, from Keowee to Oconee have been performed since initial operation of the site. Duke Power has performed inspections of all of the transmission towers throughout the Duke Power transmission and distribution system.

The requirements for the inspection of the towers and hardware are contained in the National Electric Safety Code (NESC), Part 2 Safety Rules for Overhead Lines, Rule 214 Inspection and Tests of Lines and Equipment [Reference 4.29-1]. Rule 214 states that "lines and equipment shall be inspected at such intervals as experience has shown to be necessary." The requirements of NESC Rule 214 are implemented through the Duke *Power Delivery Maintenance Standards Manual*. Section 9 of the *Maintenance Standards Manual* contains the information regarding tower inspections.

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 due to flashing from lightning strikes. The inspections have not identified wear on 230 kV line hardware. The hardware at the catch-off points at the Turbine Building were also inspected for corrosion, rust and wear.

Based on the above review, the continued implementation of the *230 kV Keowee Transmission Line Inspection* provides reasonable assurance that the aging effects will be managed such that the transmission towers will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

4.29.3 References for Section 4.29

4.29-1. *National Electric Safety Code*, published by the Institute of Electrical and Electronic Engineers, Inc., 345 East 47th Street, New York, NY, 1996.

5. TIME-LIMITED AGING ANALYSES AND EXEMPTIONS REVIEW

5.1 INTRODUCTION

As discussed in Chapter 1 of OLRP-1001, two areas of technical review are required in support of an application for a renewed operating license. The first area of technical review is the *Oconee Integrated Plant Assessment*, which is described in Chapters 2, 3, and 4 of OLRP-1001. The second area of technical review required for license renewal is the identification and evaluation of plant specific time-limited aging analyses and exemptions, which are provided in Chapter 5 of OLRP-1001.

The identification and evaluations contained in Chapter 5 meet the requirements contained in §54.21(c) and are designed to allow the NRC to make the finding contained in §54.29(a)(2).

§54.29 Standards for issuance of a renewed license

A renewed license may be issued by the Commission up to the full term authorized by §54.31 if the Commission finds that:

(a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:

(1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under §54.21(a)(1); and

(2) time-limited aging analyses that have been identified to require review under §54.21(c).

(b) Any applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied.

(c)Any matters raised under §2.758 have been addressed.

Proposed changes to reflect the Oconee-specific time-limited aging analyses are provided in the *UFSAR Supplement for License Renewal*, which is Exhibit B of the Application. The Oconee *UFSAR Supplement for License Renewal* will be incorporated into the Oconee UFSAR following the issuance of the Oconee renewed operating licenses by the NRC. Upon inclusion of descriptions of the time-limited aging analyses in the Oconee UFSAR, changes to the descriptions will be made in accordance with the change process in effect at the time of any such change.

5.2 PROCESS OVERVIEW

5.2.1 IDENTIFICATION AND EVALUATION OF TIME-LIMITED AGING ANALYSES

Section 54.21(c) requires a list of time-limited aging analyses be provided as part of the application for a renewal license. Time-limited aging analyses are defined in §54.3 as those licensee calculations and analyses that meet six specific criteria.

§54.21 Contents of Application - technical information

(c) An evaluation of time-limited aging analyses.

(1) A list of time-limited aging analyses, as defined in §54.3, must be provided. The applicant shall 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

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

§54.3 Definitions

Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in §54.4(a);

(2) Consider the effects of aging;

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

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

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

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

The process used to identify the Oconee specific time-limited aging analyses is consistent with the guidance provided in NEI 95-10, Revision 0, Chapter 5 [Reference 5.2-1].

In order to provide reasonable assurance that the Oconee time-limited aging analyses have been identified, searches of several document sets were conducted. Duke believes that the multiple searches of multiple source documents provides reasonable assurance that the Oconee time-limited aging analyses have been identified.

Oconee-specific source documents that were reviewed for time-limited aging analyses include the Oconee licensing correspondence file, the Oconee UFSAR [Reference 5.2-2], BWNT Topical Reports referenced in both correspondence and the UFSAR, and ASME Section XI Summary Reports. All Oconee time-limited aging analyses were identified in one or more of these documents.

Additional assurance in completeness of the resultant list of Oconee-specific time-limited aging analyses was obtained by reviewing several generic source documents. Specifically, in addition to the review of Oconee-specific documents, reviews were performed on several documents that are generically applicable to all pressurized water reactors. The generic source documents reviewed included the Standard Review Plan, various codes and standards, and certain NRC generic regulatory compliance documents including Bulletins, Generic Letters, Regulatory Guides, and 10 CFR Part 50 and its Appendices. The review of generic source documents confirmed the results from the review of Oconee-specific source documents.

The information developed from the review of both Oconee-specific source documents and generic source documents was reviewed to determine which calculations and analyses meet all six criteria of §54.3. The analyses and calculations that meet all six criteria were identified as Oconee-specific time-limited aging analyses. The Oconee-specific time-limited aging analyses are listed in Table 5.2-1.

As required by §54.21(c)(1), an evaluation of Oconee-specific time-limited aging analyses must be performed to demonstrate that:

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

Consistent with the information provided previously in Chapters 2, 3, and 4, the evaluation of time-limited analyses for the Reactor Building (Containment) and the Reactor Coolant System are provided in Sections 5.3 and 5.4, respectively. Likewise, the evaluation of time-limited aging analyses for mechanical components, electrical equipment, and structural components are provided in Sections 5.5, 5.6, and 5.7, respectively.

5.2.2 Identification of Exemptions

Part 54 also requires that the application for a renewed license include a list of current plant-specific exemptions granted pursuant to §50.12 that are based on time-limited aging analyses as defined in §54.3. A review of the Oconee docket has been performed and the results of this review identified that no §50.12 exemptions have been granted on the basis of a time-limited aging analysis as defined in §54.3.

5.2.3 References for Section 5.2

5.2-1. *Industry Guideline for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,* NEI 95-10, Revision 0, Nuclear Energy Institute, March 1996.

5.2-2. *Oconee Nuclear Station, Updated Final Safety Analysis Report,* as revised.

Table 5.2-1 Time-Limited Aging Analyses

1. **Containment Liner Plate and Penetrations -** Fatigue analyses on the liner plate and penetrations were identified as a time-limited aging analysis. The results of the evaluation for 60 years of operation are provided in Section 5.3.

2. **Containment Post-Tensioning System -** Loss of prestress in the post-tensioning system analyses have been identified as a time-limited aging analysis. The results of the evaluation for 60 years of operation are provided in Section 5.3.

3. **Reactor Coolant System and Class 1 Components -** Fatigue analyses and fracture mechanics analyses for ISI reportable indications have been determined to be a time-limited aging analyses. The results of the evaluation for 60 years of operation are provided in Section 5.4.1.

4. **Reactor Vessel -** Reactor vessel studs, pressurized thermal shock, Charpy upper shelf energy toughness, and intergranular separation have all been identified as time-limited aging analyses. The results of the evaluation for 60 years of operation are provided in Section 5.4.2.

5. **Reactor Vessel Internals -** Flow induced vibration, transient cycle count assumptions, and ductility -reduction of fracture toughness have been identified as time limited aging analyses. The results of the evaluation for 60 years of operation are provided in Section 5.4.3.

6. **Reactor Coolant Pump Flywheel -** Fatigue analysis of the reactor coolant pump flywheel has been identified as a time-limited aging analysis. The results of the evaluation for 60 years of operation are provided in Section 5.4.4.

7. **Mechanical Component -** Fatigue analyses have been identified as time-limited aging analyses. The results of the evaluation for 60 years of operation are provided in Section 5.5.

8. **Electrical Equipment -** The analyses that support the environmental qualification of electrical equipment have been identified as time-limited aging analyses. The results of the evaluation for 60 years of operation are provided in Section 5.6.

9. **Polar Crane -** Fatigue analysis of structural supports due to heavy load cycles has been identified as a time-limited aging analysis. The results of the evaluation for 60 years of operation are provided in Section 5.7.1.

10. **Spent Fuel Rack Boraflex -** The aging evaluation of the non-metallic Boraflex has been determined to be a time-limited aging analysis. The results of the evaluation for 60 years of operation are provided in Section 5.7.2.

5.3 TIME-LIMITED AGING ANALYSES FOR THE REACTOR BUILDING (CONTAINMENT) STRUCTURAL COMPONENTS

5.3.1 CONTAINMENT LINER PLATE AND PENETRATIONS

The interior surface of the Containment is lined with 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 following fatigue loads, as described in the Oconee UFSAR, Section 3.8.1.5.3 [Reference 5.3-1], were considered in the design of the liner plate and are considered to be time-limited aging analyses for the purposes of license renewal:

(a) Thermal cycling due to annual outdoor temperature variations. Number of cycles for this loading is 40 cycles for the plant life of 40 years.

(b) Thermal cycling due to Reactor Building interior temperature varying during the startup and shutdown of the Reactor Coolant System. The number of cycles for this loading is assumed to be 500 cycles.

(c) Thermal cycling due to the loss-of-coolant accident will be assumed to be one cycle.

(d) 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 a conservative number of cycles to be expected during the plant life.

Each of the above four time-limited aging analyses have been evaluated for continued operation for up to 60 years. For item (a), 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 Containment interior temperature varying during heatup and cooldown of the Reactor Coolant System. Thus, this time-limited aging analysis is considered to be valid for the period of extended operation as it is enveloped with item (b) above.

For item (b), with respect to the assumed 500 thermal cycles due to startup and shutdown of the Reactor Coolant System, a more limiting number of thermal cycles is contained in the Oconee UFSAR, Section 5.2 [Reference 5.3-1] for actual plant operation. Oconee UFSAR , Table 5.2 [Reference 5.3-1] indicates a design limit of 360 heatup cycles and 360 cooldown cycles for the Reactor Coolant System. The projected number of cycles for each Oconee unit through 60 years of operation has been determined to be less than the original 360 cycle design limits. This time-limited aging analysis 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. [Footnote 8]

For item (c), the assumed value for thermal cycling due to loss-of-coolant accident remains valid. None have occurred and none are expected to occur. This time-limited aging analysis is considered to be valid for the period of extended operation.

Finally for item (d), the design of the Containment penetrations has been reviewed. The design meets the general requirements of ASME Section III for thermal cycling [Reference 5.3-2]. The only high temperature lines penetrating the Containment wall and liner plate are the feedwater and main steam lines. 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 Oconee unit through 60 years of operation has been determined to be less than these original design limits. Thus, based on a review of the existing fatigue analysis, this time-limited aging analysis 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 ten 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. [Footnote 9]

8. See Section 5.4.1.1 for an evaluation of the thermal fatigue cycles of the Reactor Coolant System.
9. This section has been revised to supplement the initial Duke response to RAI 3.3-6 which was provided by Duke letter dated January 14, 1998. The initial Duke response to RAI 3.3-6 was discussed during a meeting with the NRC staff on April 29, 1998.

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.

5.3.2 Containment Post-Tensioning System

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 time-limited aging analysis requiring review for license renewal.

In accordance with ACI 318-63 [Reference 5.3-3] the design of the Oconee Containment post-tensioning system provides for prestress losses caused by the following:

- Elastic shortening of concrete
- Creep of concrete
- Shrinkage of concrete
- Relaxation of prestressing steel stress
- Frictional loss due to curvature in the tendons and contact with tendon conduit.

No allowance is provided for seating of the anchor since no slippage occurs in the anchor during transfer of the tendon load into the structure [Reference 5.3-1].

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 at the end of 40 years for typical dome, vertical, and hoop tendons was calculated at the time of initial licensing. This analysis is presently summarized in the Oconee UFSAR, Section 3.8.1.5.2 [Reference 5.3-1].

In 1996, Oconee provided a description of the methodology for determining the most accurate minimum required lift-off force for each tendon group for NRC review [Reference 5.3-4]. Based upon the results of the evaluation of the submitted information and commitments made by Duke, the NRC staff has determined that the integrity of the Oconee Containment is adequate to support continued operation [Reference 5.3-5].

Containment post-tensioning system surveillance will be performed in accordance with Oconee Improved Technical Specification SR 3.6.1.2 (Oconee Custom Technical Specification 4.4.2). Acceptance criteria for tendon surveillance are given in terms of Prescribed Lower Limits and Minimum Required Values. Oconee Selected Licensee Commitment, Oconee UFSAR, SLC 16.6.2 [Reference 5.3-1] provides the required prescribed lower limits and minimum required values 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, respectively, for all three Oconee units. The figures have been developed using the guidance contained in Regulatory Guide 1.35 [Reference 5.3-6]. Each prescribed lower limit line has been extended to 60 years of plant operation and remains above the minimum required values 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.

5.3.3 References for Section 5.3

5.3-1. *Oconee Nuclear Station, Updated Final Safety Analysis Report,* as revised.

5.3-2. ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Vessels," 1965.

5.3-3. American Concrete Institute, *Building Requirements for Reinforced Concrete,* ACI 318-63, Detroit, Michigan.

5.3-4. J. W. Hampton (Duke) letter dated March 14, 1996 to Document Control Desk (NRC), Docket Numbers 50-269, 50-270, 50-287, Response to Request for Additional Information Concerning Reactor Building Post-Tensioning Systems, Sixth Surveillance.

5.3-5. D. E. LaBarge (NRC) letter dated November 7, 1996, Reactor Building Post-Tensioning System Sixth Surveillance - Oconee Nuclear Station, Unit 3 (TAC NO. M93942).

5.3-6. Regulator Guide 1.35, *Inservice Inspection of Ungrouted Tendons in Prestressed Concrete Containments, Revision 3,* U. S. Nuclear Regulatory Commission, July 1990.

5.4 TIME-LIMITED AGING ANALYSES FOR THE REACTOR COOLANT SYSTEM AND CLASS 1 COMPONENTS

Duke actively participated in a B&W Owners Group effort that developed a series of topical reports whose purpose was to demonstrate that the aging effects for Reactor Coolant System components are adequately managed for the period of extended operation for license renewal. Two B&W Owners Group topical reports have been submitted and approved by NRC for use by applicants for a renewed operating license. BAW-2243A [Reference 5.4-1] addresses Reactor Coolant System piping and BAW-2244A [Reference 5.4-2] addresses the pressurizer. In each of these reports, the commitment was made to address applicable time-limited aging analyses on a plant specific basis. For Oconee Reactor Coolant System piping, the applicable time-limited aging analyses are thermal fatigue [see Section 5.4.1.1] and flaw growth acceptance under ASME Boiler and Pressure Code Section XI [see Section 5.4.1.2].

BAW-2243A identified leak-before-break and high energy line break postulation based on fatigue cumulative usage factor (CUF>0.1) as generically applicable time-limited aging analyses. However, the review conducted of Oconee documentation determined that neither the leak-before-break analyses nor the cumulative usage factor (CUF>0.1) analyses are time-limited aging analyses for Oconee. For the Oconee pressurizer, the applicable time-limited aging analyses are thermal fatigue [see Section 5.4.1.1] and flaw growth acceptance under ASME Boiler and Pressure Code Section XI [see Section 5.4.1.2].

As a result of NRC review of these B&W Owners Group reports, several Renewal Applicant Action Items were identified. These Action Items are described in Section 4.1 of the Safety Evaluations issued by the NRC concerning BAW-2243A [Reference 5.4-3] and BAW-2244A [Reference 5.4-4]. One Renewal Applicant Action in each of the NRC Safety Evaluations requires that the renewal applicant referencing the reports evaluate the applicable time-limited aging analyses for both the Reactor Coolant System piping and the pressurizer. Section 5.4.1 provides the evaluation of the applicable time-limited aging analyses for Oconee Reactor Coolant System piping and pressurizer.

5.4.1 Reactor Coolant System Piping and Components

5.4.1.1 Thermal Fatigue

5.4.1.1.1 BACKGROUND

The issue of design assumptions associated with thermal fatigue of Reactor Coolant System components has been identified as a time-limited aging analysis for Oconee. All six of the criteria contained in §54.3 are satisfied. Specific Reactor Coolant System components have been designed considering transient cycle assumptions as listed in Table 5-4 of the Oconee Updated Final Safety Analysis Report (UFSAR) [Reference 5.4-5], except the pressurizer surge line which is covered in Table 5-23. Because the initial design of the Oconee Reactor Coolant System was divided between B&W, who designed the main Reactor Coolant System components and piping, and Bechtel, who designed the piping linking the interconnected systems to the Reactor Coolant System, the evaluation of each vendor's piping design is performed separately. [Footnote 10]

5.4.1.1.2 B & W SCOPE OF SUPPLY

The B&W scope of supply includes all the major components in the Reactor Coolant System and the associated interconnected piping. These components are designed to ASME Section III and USAS B31.7 Class I, collectively known as Class 1 standards. An analysis was performed to determine which B&W Class 1 components may require additional actions when considering 60 years of operation.

The review began with the thermal transient cycle count assumptions from the B&W Reactor Coolant System Functional Specification which is captured in the trackable transient set listed in the Oconee UFSAR [Reference 5.4-5]. This trackable transient set can be found in the Oconee UFSAR Table 5-2 for Reactor Coolant System components, except the pressurizer surge line which is covered in Table 5-23. Next, actual plant operating thermal transient cycle count data were used to determine where the component was in its fatigue lifetime. From there, a conservative cycle accumulation rate was used to project when plant operation would exceed the number of design cycles for the given transients. Exceeding this limit does not necessarily mean the component will fail or even that the cumulative usage factor will be 1.0, but rather that the component may require further evaluation.

10. GSI 190, "Fatigue evaluation of metal components for 60-year life" is addressed in Section 1.5.5 of OLRP-1001.

The locations that require further evaluation include the reactor vessel studs for all three units, the pressurizer spray line for Unit 3, and the Emergency Feedwater System nozzle for Unit 3. The trackable transient set for all Reactor Coolant System components, including those that require further evaluation, is being managed by the Oconee *Thermal Fatigue Management Program.*

For license renewal, continuation of the Oconee *Thermal Fatigue Management Program* into the period of extended operation will assure that the analyses remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

5.4.1.1.3 BECHTEL SCOPE OF SUPPLY

The Bechtel scope of supply for the Reactor Coolant System included the following attached piping:

- Low Pressure Injection (LPI) / Core Flood (CF) Piping
- Pressurizer Spray Bypass Line / Auxiliary Spray Piping
- High Pressure Injection (HPI) - Emergency Injection Piping
- High Pressure Injection (HPI) - Normal Makeup Piping
- Low Pressure Injection - Decay Heat Drop Line (including Dump-to-Sump)
- High Pressure Injection Letdown Piping
- All RCS Loop Drains

This attached piping was originally designed to USAS B31.7, Class I standards, except for the piping analysis which was done to Class II standards. Specifically, the pipe sizing, materials selection and non-destructive examination were all performed to Class I standards. The piping analysis was performed to Class II standards. From a review of the Oconee design files, Bechtel performed only a Class II analysis on this attached piping because their limited computer capabilities in 1969 would not allow them to perform a Class I analysis. This design detail was inadvertently overlooked in the Oconee UFSAR presentation of the Reactor Coolant System design standards where, at the time of NRC review in 1994, it was reported that the reactor coolant pressure boundary, including the attachment piping to the first isolation valve, was designed to USAS B31.7, Class I standards. Following the 1994 NRC visit, as discussed further in Section 5.0, wherein review of calculational details identified the Class II analysis basis and the inconsistency with the Oconee UFSAR, Oconee committed to the NRC to complete Class I analyses for the attached piping out to the first isolation valve [References 5.4-6, 5.4-7, and 5.4-8].

As of June 1998, the reanalysis of these connecting lines is underway. The technical information contained in this portion of the application will be supplemented after the completion of the reanalysis. For license renewal, the results of the Class I reanalysis for the Reactor Coolant System attached lines will establish a more easily trackable fatigue design basis which will allow fatigue management through 60 years of operation. Upon completion of the reanalysis, these attached piping components will be added to the Oconee *Thermal Fatigue Management Program*.

For license renewal, continuation of the Oconee *Thermal Fatigue Management Program* into the period of extended operation will assure that the analyses remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

5.4.1.1.4 IE BULLETIN 88-11, PRESSURIZER SURGE LINE STRATIFICATION

Since the beginning of initial operation, specific industry operating issues associated with thermal fatigue have arisen and licensees have evaluated these issues relative to their existing design configuration. The first of two such issues evaluated at Oconee was IE Bulletin 88-11 which requested that all domestic, commercial pressurized water reactors establish and implement a program to determine the impact of thermal stratification on pressurizer surge line integrity. The elements of this program are as follows [Reference 5.4-9]:

(1) Conduct of an initial ASME Section XI VT-3 examination of the entire pressurizer surge line to determine any gross structural damage which may have resulted from surge line movement due to thermal stratification.
(2) Demonstration by analysis that the pressurizer surge line meets applicable design codes and current licensing basis commitments for the licensed life of the plant, considering the phenomenon of thermal stratification.
(3) Collection of plant-specific data on thermal stratification where the analysis does not demonstrate compliance with the current licensing basis.
(4) Revision of the stress and fatigue analyses using the applicable plant specific data to demonstrate compliance with the current licensing basis.

A comparison of actual operating experience to the design transient cycle count assumptions, including a projection of assumed future cycles, must be done to determine the validity of the pressurizer surge line reanalysis when considering 60 years of operation.

Original design analyses of the surge line did not include stratified flow loading conditions. An assessment of stratification effects on the pressurizer surge line was necessary to ensure piping integrity and code compliance. The review of the pressurizer surge line stratification concern was performed in several stages. Oconee participated in the B&W

Owners Group effort to review data from a B&W plant in Germany (Muelheim-Kaerlich) and also was actively involved in an extensive data collection program on Oconee Unit 1. Additionally, inspections of the surge line design at Oconee determined only snubbers were used and no rigid or whip restraints exist on the pipe that could restrict the expansion. A B&W Owners Group Report BAW-2085 was prepared to justify short term plant operation and to present a bounding analysis. The final report BAW-2127 was later submitted to complete the actions requested in the Bulletin [Reference 5.4-10]. Activities which were completed to re-establish the design basis include revision of the B&W Reactor Coolant System Functional Specification, placing restrictions on the heat-ups and cooldowns (this was the genesis of Oconee UFSAR Table 5-23), and reanalysis of the piping configuration to take thermal stratification into consideration.

Through the series of correspondences in References 5.4-11 and 5.4-12, the NRC reviewed the Oconee responses and determined the actions taken by Oconee met the requirements of the Bulletin. The identified thermal stresses are now represented in the appropriate stress calculations and the thermal transient cycle count assumptions for the reanalyzed pressurizer surge line are included in the review described in Section 5.4.1.1.2.

The inclusion of the pressurizer surge line reanalysis information within the Reactor Coolant System piping fatigue design means that no additional plant program is required to track the fatigue design basis for 60 years of operation. The trackable transient set for all Reactor Coolant System components, which includes the pressurizer surge line, will be managed by the Oconee *Thermal Fatigue Management Program.* Inclusion of this information in this program will go beyond addressing the pressurizer surge line reanalysis to meet the requirements of IE Bulletin 88-11 and will assure that the analysis will remain valid for the period of extended operation.

For license renewal, continuation of the Oconee *Thermal Fatigue Management Program* into the period of extended operation will assure that the pressurizer surge line reanalysis remains valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

5.4.1.1.5 IE BULLETIN 88-08, THERMAL STRESSES IN PIPING CONNECTED TO REACTOR COOLANT SYSTEMS

Since the beginning of initial operation, specific industry operating issues associated with thermal fatigue have arisen and licensees have evaluated these issues relative to their existing design configuration. The second of two such issues evaluated at Oconee was

IE Bulletin 88-08 which requested that all light-water-cooled nuclear power reactor licensees review their Reactor Coolant System designs to identify any connected, unisolable piping that could be subjected to temperature distributions which would result in unacceptable thermal stresses. The elements of this review program are as follows [Reference 5.4-6]:

(1) Review systems connected to the RCS to identify any connected, unisolable piping that could be subjected to temperature distributions which would result in unacceptable thermal stresses.
(2) Perform nondestructive examination on the welds, heat-affected zones and high stress locations in any piping sections identified in (1) to assure that there are no existing flaws.
(3) Implement a program to provide continuing assurance that unisolable sections of piping systems connected to RCS will not be subjected to thermal and mechanical loadings that could cause fatigue failure.

A comparison of actual operating experience to the design transient cycle count assumptions, including a projection of assumed future cycles, must be done to determine the validity of any analysis performed on the unisolable sections of piping systems connected to the Reactor Coolant System when considering 60 years of operation.

Specific industry issues associated with thermal fatigue were identified for lines connecting to the Reactor Coolant System in IE Bulletin 88-08, *Thermal Stresses in Piping Connected to the Reactor Coolant System*. The bulletin, issued on June 22, 1988, identified a potential generic problem associated with an incident at Farley Nuclear Plant. The incident which was first reported in NRC Information Notice 88-01 involved a through wall pipe crack in an emergency core cooling system line. The crack was attributed to high cycle thermal fatigue resulting from valve leakage. The bulletin identified certain actions and reporting requirement for the licensees. Subsequent Supplements 1,2 and 3 to the bulletin provided additional information on other similar cracks and emphasized the need for sufficient review of the Reactor Coolant System to identify any connected, unisolable piping that could be subjected to thermal stratification and the importance of taking action for any such identified piping to ensure that the piping would not be subjected to unacceptable thermal stresses.

Through a series of correspondences [Reference 5.4-13], the NRC was provided the results of the Oconee review. The emergency injection lines of the High Pressure Injection system were identified as the only unisolable piping potentially susceptible to unacceptable thermal stresses resulting from the type of event described in the bulletin. The actions prescribed by the bulletin were completed for these lines in question.

In addition to the work described here for the bulletin on the emergency injection lines of the High Pressure Injection system, the fatigue design of both the normal and emergency injection lines, particularly the nozzles connecting to the main Reactor Coolant System piping was called into question following the April 21, 1997, unisolable Reactor Coolant System leak on Oconee Unit 2. The cause of the leak was a crack in the weld connecting the piping to the nozzle safe-end on one of the two normal injection lines in the High Pressure Injection system. The cause was judged to be thermal fatigue.

Following this event and subsequent NRC inspection, the NRC issued a Notice of Violation which called into question actions Oconee had taken in response to Generic Letter 85-20 where an augmented inservice inspection program had been established for detection of High Pressure Injection system cracks. Oconee actions are further described in Section 5.4.7.2 of the Oconee UFSAR [Reference 5.4-3].

The Notice of Violation [Reference 5.4-14] and Duke's response [Reference 5.4-15] provide additional details. The important issue for license renewal application development is the timing of the commitment in Reply 3(d) to Violation b(2) in Duke's response to provide a revised submittal to IE Bulletin 88-08. In a February 26, 1998 letter [Reference 5.4- 16] which served as a follow-up to the initial response to the Notice of Violation, Oconee committed to provide a final supplement to IE Bulletin 88-08 by July 1, 2000. As of June 1998, the work to meet this commitment is ongoing.

For license renewal, the results of the revised IE Bulletin 88-08 submittal will establish a more easily trackable fatigue design basis which will allow fatigue management of the High Pressure Injection lines through 60 years of operation. Upon completion of the reanalysis which supports this revised IE Bulletin 88-08 submittal, the High Pressure Injection results will be included in the Oconee *Thermal Fatigue Management Program.*

For license renewal, continuation of the Oconee *Thermal Fatigue Management Program* into the period of extended operation will assure that the analyses remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

5.4.1.2 Flaw Growth Acceptance under ASME Boiler and Pressure Code Section XI

As background, the NRC periodically amends §50.55a [Reference 5.4-17] to incorporate by reference an edition and applicable Addenda of the ASME Boiler and Pressure Vessel Code, Section XI, with specified modifications and limitations. Throughout the service life of nuclear power plants, components which are classified as ASME Code Class 1, must meet the requirements, except design and access provisions and preservice examination requirements, set forth in Section XI of editions of the ASME Code and Addenda that are incorporated by reference in §50.55a(b). These requirements are subject to the limitations and modifications described in §50.55a and to the extent practical within the limitations of design, geometry and materials of construction of the components [Reference 5.4-17, ¶ (g)(4)].

Inservice examination of components and system pressure tests conducted during successive 120-month inspection intervals, following the initial 120-month inservice inspection interval, must comply with the requirements of the latest edition and Addenda of the Code incorporated by reference in §50.55a(b) twelve months prior to the start of the 120-month inspection interval, subject to the limitations and modifications listed in paragraph §50.55a(b) [Reference 5.4-17, ¶(g)(4)(ii)]. Oconee is currently operating in the third inservice inspection interval. The renewal license period of extended operation for Oconee will contain the fifth and sixth inservice inspection intervals.

The ASME Section XI inservice inspection (ISI) requirements are contained in Subsection IWB for Class 1 pressure retaining components, Subsection IWC for Class 2 pressure-retaining components, and Subsection IWD for Class 3 pressure retaining components. Inservice inspection at Oconee has, in a number of instances, lead to the identification of crack-like indications (primarily in welds). For indications detected during ISI that exceed acceptance standards in IWB, IWC, and IWD (1) repairs may be made, (2) affected portions of the component may be replaced, or (3) the flaw may be shown to be acceptable through analytical evaluation.

Acceptance through analytical evaluation requires a prediction of crack growth through the end of service life of the component. The crack growth analysis is based on fracture mechanics techniques and helps determine the course of action required in the management of these flaws. Indications that are determined not to grow beyond an acceptable limit during the projected lifetime of the component are justified for continued operation. These crack growth analyses involve the same design thermal transient cycle assumptions considered in the original design. Because the crack growth rate determined by these analyses may further limit the design life of the components, a review of these analyses is required in order to justify 60 years of operation. For license renewal, Duke identified the specific fracture mechanics analyses that have been performed at Oconee and then re-evaluated these analyses for the period of extended operation.

A review of the ASME Section XI Summary Reports was initially conducted for all reportable conditions discovered during the first and second inspection intervals for each of the three Oconee units. The scope of this review was limited to the reportable items for which fracture mechanics analyses or other evaluations were performed. The summary reports initially reviewed were for Refueling Outages 1 through 15 for Oconee Unit 1; Refueling Outages 1 through 14 for Unit 2; and Refueling Outages 1 through 14 for Unit 3. Subsequently, as refueling outages are completed, fracture mechanics analyses are also being reviewed for acceptability for the period of extended operation.

The results of this review have identified the following general flaw locations that have not been demonstrated to be acceptable for the number of controlling design basis transients (e.g., 360 design cycles or normal heatup/cooldown):

Oconee Unit 1:

- Pressurizer near heater bundle
- Pressurizer support lugs
- OTSG at the upper head to tubesheet region
- Reactor vessel at the reactor vessel flange to shell region
- Control rod drive motor tube housings

Oconee Unit 2:

- Core Flood Tank dump valve to nozzle
- Pressurizer upper head to shell region
- Control rod drive motor tube housings

Oconee Unit 3:

- None

These locations with limiting transient assumptions are being managed under the Oconee *Thermal Fatigue Management Program.*

5.4.1.3 Thermal Fatigue Management Program

The *Thermal Fatigue Management Program* tracks actual plant thermal cycles for those components that contain design features that have explicit design basis transient cycle assumptions in order to assure the continued validity of the component design basis. The component scope requiring design thermal cycle limit confirmation for license renewal is:

(1) Reactor Coolant System components (including piping connected to the Reactor Coolant System falling under the purview of IE Bulletins 88-11 and 88-08).
(2) Components falling within the Oconee ISI Program that contain flaws detected during ISI that exceeded acceptance standards, but were shown to be acceptable by analysis. Fracture mechanics analyses for these components will fall into two categories:

(a) ASME Section XI ISI Class 1 fracture mechanics analyses
(b) ASME Section XI ISI Class 2 or 3 fracture mechanics analyses that are based on cycle assumptions less than 7000 cycles (or 22,000 cycles for the components in the pressurizer sample line)

From continual monitoring of plant operating conditions, the responsible engineer will discover plant conditions that meet the definition of a transient cycle defined by this program. Upon discovery of each transient cycle required to be documented by the program, the responsible engineer will tabulate the cycle count information. The tabulated information allows a comparison of the accumulated cycles to the overall allowable cycles required to be documented. Not all transient events require documenting since some analysis categories assumed values that far exceed what can be accomplished physically within 60 years of plant operation, and some transient events will result in negligible fatigue. If a transient cycle count approaches or exceeds the allowable design limit, corrective action steps are taken.

The Oconee *Thermal Fatigue Management Program* is implemented by an engineering procedure in accordance with Oconee ITS 5.5.6, *Component Cyclic or Transient Limit* for components covered within Oconee UFSAR, Section 5.2.1.4. These components comprise set (1) above. For license renewal, the program will be enhanced to more explicitly cover the components in set (2).

For license renewal, continuation of the Oconee *Thermal Fatigue Management Program* into the period of extended operation will provide reasonable assurance that the analyses will remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

5.4.2 Reactor Vessel

Duke actively participated in a B&W Owners Group effort that developed a series of topical reports whose purpose was to demonstrate that the aging effects for reactor coolant system components are adequately managed for the period of extended operation for license renewal. One of the B&W Owners Group topical reports that was submitted and is currently under NRC review is BAW-2251 [Reference 5.4-18] which addresses the reactor vessel. Time-limited aging analyses applicable to the reactor vessel are addressed within BAW-2251. Pending approval of BAW-2251 by the NRC, these time-limited aging analysis evaluations are repeated in OLRP-1001. However, in some instances (i.e. pressurized thermal shock and upper shelf energy) the results for Oconee supersede those results presented in BAW-2251.

Time-limited aging analyses that are applicable to the Reactor Vessel include (1) thermal fatigue which is addressed in Section 5.4.1.1; (2) flaw growth acceptance under ASME Boiler and Pressure Code Section XI which is addressed in Section 5.4.1.2; and (3) neutron embrittlement of the beltline region, including pressurized thermal shock and Charpy upper-shelf energy reduction, is addressed in Sections 5.4.2.1 and 5.4.2.2; and (4) intergranular separation in HAZ of low alloy steel under austenitic stainless steel weld cladding is addressed in Section 5.4.2.3.

The Oconee *Reactor Vessel Integrity Program* as described in Chapter 4 of OLRP-1001 is being utilized to ensure that the time dependent parameters used in the TLAA evaluations reported in BAW-2251 are tracked such that the TLAA remain valid through the period of extended operation for Oconee [Footnote 11].

5.4.2.1 Pressurized Thermal Shock

Section 50.61(b)(1) provides rules for protection against pressurized thermal shock events for pressurized water reactors. Licensees are required to perform an assessment of the projected values of reference temperature whenever a significant change occurs in projected values of RT_{PTS}, or upon request for a change in the expiration date for the operation of the facility. For license renewal, RT_{PTS} values are calculated for 48 EFPY for Oconee Units 1, 2, and 3.

11. Follow-up RAI #4 to BAW-2251 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 remain valid through the period of extended operation.” The GLRP response indicated that the process would be defined on a plant-specific basis at the time of license renewal application.

Section 50.61(c) provides two methods for determining RT_{PTS}: (Position 1) for material that does not have surveillance data available, and (Position 2) for material that does have surveillance data. Availability of surveillance data is not the only measure of whether Position 2 [Footnote 12] may be used; the data must also meet tests of sufficiency and credibility.

$\mathbf{RT_{PTS}}$ is the sum of the initial reference temperature (IRT_{NDT}), the shift in reference temperature caused by neutron irradiation (ΔRT_{NDT}), and a margin term (M) to account for uncertainties.

$\mathbf{IRT_{NDT}}$ is determined using the method of Section III of the ASME Boiler & Pressure Vessel Code. That is, IRT_{NDT} is the greater of the drop weight nil-ductility transition temperature or the temperature that is 60 °F below that at which the material exhibits Charpy test values of 50 ft-lbs and 35 mils lateral expansion. For a material for which test data is unavailable, generic values may be used if there are sufficient test results for that class of material. For Linde 80 weld material with the exception of WF-70, the IRT_{NDT} is taken to be the currently NRC accepted values of -7 °F or -5 °F. For WF-70, the IRT_{NDT} is similarly taken to be a measured value, -26.5 °F, in accordance with the discussion and results presented in BAW-2202 [Footnote 13][Reference 5.4-19]. For forgings and plate material, measured values are used where appropriate data is available. Where not available, the generic value of +3 °F is used for forgings and +1 °F is used for plate material [Reference 5.4-20].

For Position 1 material (surveillance data not available), $\mathbf{\Delta RT_{NDT}}$ is defined as the product of the chemistry factor (**CF**) and the fluence factor (**ff**). **CF** is a function of the material's copper and nickel content expressed as weight percent. "Best estimate" copper and nickel contents are used which is the mean of measured values for the material. For Oconee, best estimate values were obtained from the following FTI reports: BAW-1820, BAW-2121P, BAW-2166, and BAW-2222 [Footnote 14][References 5.4-21, 5.4-22, 5.4-23, and 5.4-24]. The value of

12. The term "Position" is taken from Regulatory Guide 1.99, the methodology of which was incorporated into 10 CFR 50.61.

13. BAW-2202 is an FTI topical report submitted to the NRC for their acceptance on September 29, 1993. The NRC's acceptance for use at the Zion plants was published in the Federal Register, Vol. 59, No. 40, Pages 9782-9785, March 1, 1994.

14. BAW-1820 and BAW-2121P were provided to the NRC for their information. BAW-2166 and BAW-2222 were provided to the NRC as part of the Generic Letter 92-01 program.

CF is directly obtained from tables in §50.61. **ff** is a calculated value [Footnote 15] using end-of-license (EOL) peak fluence at the inner surface at the material's location. Fluence values were obtained by extrapolation to 48 EFPY of the current 32 EFPY values for each Oconee unit.

For beltline welds and plate materials for which surveillance data is available, evaluations were performed in accordance with Regulatory Guide 1.99, Revision 2, Position 2. The applicable chemistry factors, margin, and RT_{PTS} at 48 EFPY are summarized in Tables 5.4-1 through 5.4-3.

For Position 2 material (surveillance data available), the discussion above for Position 1 applies except for determination of **CF**, which in this instance is a material-specific value calculated as follows:

(1) Multiply each ΔRT_{NDT} value by its corresponding **ff**.

(2) Sum these products.

(3) Divide this sum by the sum of the squares of the **ff**s.

The **margin** term (M) is generally determined as follows:

$$M = 2(\sigma_I^2 + \sigma_\Delta^2)^{0.5}$$

where σ_I is the standard deviation for IRT_{NDT}

and σ_Δ is the standard deviation for ΔRT_{NDT}.

For Position 1, $\sigma_I = 0$ if measured values are used. If generic values are used, σ_I is the standard deviation of the set of values used to obtain the mean value. For ΔRT_{NDT}, σ_Δ = 28°F for welds and 17°F for base metal (plate and forgings), except that σ_Δ need not exceed one-half of the mean value of ΔRT_{NDT}. For Position 2, the same method for determining the σ values are used except that the σ_Δ values are halved (14°F for welds and 8.5°F for base metal).

15. $ff = f^{(0.28-0.1*\log f)}$, where f = fluence*$10^{-19}$ (n/cm^2, E>1MeV).

Section 50.61(b)(2) establishes screening criteria for RT_{PTS} : 270º F for plates, forgings, and axial welds and 300ºF for circumferential welds. The values for RT_{PTS} at 48 EFPY are provided in Tables 5.4-1, 5.4-2, and 5.4-3 for Units 1, 2, and 3, respectively and supersede the values provided in Appendix A of BAW-2251 [Reference 5.4-18] for Oconee Nuclear Station. The revised RT_{PTS} values reported herein are based on updated 48 EFPY fluence projections using the evaluation based methodology described in BAW-2251 Appendix D and BAW-2241P [Reference 5.4-25].

The projected RT_{PTS} values for Units 1 and 3 are within the established screening criteria for 48 EFPY. For Unit 1, the limiting weld is SA-1073 with a projected value of RT_{PTS} at 48 EFPY of 230.3ºF (screening limit of 270ºF). For Unit 3, the limiting weld is WF-67 with a projected value of RT_{PTS} at 48 EFPY of 253.5ºF (screening limit of 300ºF).

For Unit 2, the projected RT_{PTS} value for 48 EFPY is 300.1ºF which is 0.1ºF above the established screening criteria or 300ºF for circumferential welds. Section 50.61(b)(3) requires that licensees implement flux reduction programs that are reasonably practical to avoid exceeding the screening criteria set forth in §50.61(b)(2).

Duke commits to the following activities in order to avoid exceeding these screening criteria at Oconee during the period of extended operation:

(1) Duke will continue our practice of using low leakage core designs for each unit of Oconee;
(2) Duke will continue our involvement in various industry activities that provide new information or new analysis techniques associated with the reactor vessel beltline region. These activities include, but are not limited to, the development of the master curve technique which will establish a generic initial value of RT_{NDT} of -27 °F Linde 80 welds (WF 25, the limiting weld for Unit 2 is a Linde 80 weld);
(3) Duke will provide additional projected values of RT_{PTS} at 48 EFPY for each Oconee unit as follows:
    (a) in 2013 (which is 40 years of operation or approximately 33 EFPY)
    (b) in 2023 (which is 50 years of operation or approximately 41 EFPY)

5.4.2.2 Charpy Upper-Shelf Energy

Appendix G of 10 CFR 50 requires that reactor vessel beltline materials "have Charpy upper-shelf energy ... of no less than 75 ft-lb initially and must maintain Charpy upper-shelf energy throughout the life of the vessel of no less than 50 ft-lb ... ." The B&WOG positions on upper shelf energy for 32 EFPY are documented in the responses to Generic Letter 92-01, as reported in BAW-2166 and BAW-2222 and, the low upper shelf toughness analyses documented in BAW-2275 [Reference 5.4-26], which is included in BAW-2251 [Reference 5.4-18] as Appendix B.

Regulatory Guide 1.99, Revision 2 provides two methods for determining Charpy upper-shelf energy (C_VUSE): Position 1 for material that does not have surveillance data available and Position 2 for material that does have surveillance data. For Position 1, the percent drop in C_VUSE, for a stated copper content and neutron fluence, is determined by reference to Figure 2 of Regulatory Guide 1.99, Revision 2. This percentage drop is applied to the initial C_VUSE to obtain the adjusted C_VUSE. For Position 2, the percent drop in C_VUSE is determined by plotting the available data on Figure 2 and fitting the data with a line drawn parallel to the existing lines that upper bounds all the plotted points.

The 48 EFPY C_VUSE values were determined for the reactor vessel beltline materials for each Oconee Unit are reported in Table 5.4-4 through 5.4-6. The T/4 fluence values reported in these tables were calculated in accordance with the ratio of inner surface to T/4 values (i.e. neutron fluence lead factors at T/4) determined in the latest Reactor Vessel Surveillance Program report [Footnote 16]. As shown in these tables, the C_VUSE is maintained above 50 ft-lb for base metal (plates and forgings), however, for Oconee the C_VUSE for weld metal drops below the required 50 ft-lb level at 48 EFPY. Appendix G of 10 CFR 50 provides for this by allowing operation with lower values of C_VUSE if " … it is demonstrated ... that the lower values of Charpy upper-shelf energy will provide margins of safety against fracture equivalent to those required by Appendix G of Section XI of the ASME Code."

This equivalent margin analysis was performed for 48 EFPY and is reported in BAW-2275 for service levels A, B, C, and D. The analysis used very conservative material models and load combinations, i. e., treating thermal gradient stress as a primary stress. For service levels A and B, the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code (1995 Edition). For service levels C and D, the most limiting transient was evaluated, and again the analytical results demonstrate that there is sufficient margin beyond that required by the acceptance criteria of Appendix K of the ASME Code. The evaluations for all service levels conclusively demonstrate the adequacy

16. The current projected 48 EFPY fluence values for Unit 1 welds are slightly greater than that reported in BAW-2251, Table 4-4. A calculation has been performed which shows that the weld metals of Oconee Unit 1 continue to satisfy the acceptance criteria of Appendix K of Section XI of the ASME Code. The current projected 48 EFPY fluence values for Units 2 and 3 are less that those values presented in BAW-2251, Tables 4-5 and 4-6. The values reported in these two tables of BAW-2251 are conservatively bounding.

of margin of safety against fracture for the three Oconee reactor vessels within the scope of this report for 48 EFPY.

5.4.2.3 Intergranular Separation in HAZ of Low Alloy Steel under Austenitic SS Weld Cladding

Intergranular separations in low alloy steel heat-affected zones under austenitic stainless steel weld claddings were detected in SA-508, Class 2 reactor vessel forgings manufactured to a coarse grain practice, and clad by high-heat-input submerged arc processes. BAW-10013 contains a fracture mechanics analysis that demonstrates the critical crack size required to initiate fast fracture is several orders of magnitude greater than the assumed maximum flaw size plus predicted flaw growth due to design fatigue cycles. The flaw growth analysis was performed for a 40-year cyclic loading, and an end-of-life assessment of radiation embrittlement (i.e., fluence at 32 EFPY) was used to determine fracture toughness properties. The report concluded that the intergranular separations found in B&W vessels would not lead to vessel failure. This conclusion was accepted by the AEC [Footnote 17]. To cover the period of extended operation, an analysis was performed using current ASME Code requirements; this analysis is fully described in BAW-2274 [Reference 5.4-27] which is contained in BAW-2251 as Appendix C.

In May 1973, the Atomic Energy Commission issued Regulatory Guide 1.43, "Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components," [Reference 5.4-28]. The guide states that underclad cracking "…has been reported only in forgings and plate material of SA-508 Class 2 composition made to coarse grain practice when clad using high-deposition-rate welding processes identified as 'high-heat-input' processes such as the submerged-arc wide-strip and the submerged-arc 6-wire processes. Cracking was not observed in clad SA-508 Class 2 materials clad by 'low-heat-input' processes controlled to minimize heating of the base metal. Further, cracking was not observed in clad SA-533 Grade B Class 1 plate material, which is produced to fine grain practice. Characteristically, the cracking occurs only in the grain-coarsened region of the base-metal heat-affected zone at the weld bead overlap." The guide also notes that the maximum observed dimensions of these subsurface cracks is 0.165-inch deep by 0.5-inch long.

The BAW-10013 fracture mechanics analysis is a flaw evaluation performed before the ASME Code requirements for flaw evaluation, the K_{Ia} curve for ferritic steels as indexed against RT_{NDT}, and the ASME Code fatigue crack growth curves for carbon and low alloy ferritic steels were available. The revised analysis uses current fracture toughness

17. R. C. DeYoung (USAEC) to J. F. Mallay (B&W), letter transmitting topical report evaluation, October 11, 1972.

information, applied stress intensity factor solutions, and fatigue crack growth correlations for SA-508 Class 2 material. The objective of the analysis is to determine the acceptability of the postulated flaws for 48 EFPY using ASME Code, Section XI, (1995 Edition), IWB-3612 acceptance criteria.

The revised analysis was applied to three relevant regions of the reactor vessel: the beltline, the nozzle belt, and the closure head/head flange. The analysis conservatively considered 360 cycles of 100 F/hr normal heatup and cooldown transients. For the power maneuvering transients, the range in applied stress intensity factors for the closure head region were assumed to be the same as that determined for the beltline region. This assumption is considered conservative since the closure head region is subject to a low flow condition while the beltline region is subject to a forced flow condition.

An initial flaw size of 0.353-inch deep by 2.12-inch long (6:1 aspect ratio) was conservatively assumed for each of the three regions. The flaw was further assumed to be an axially oriented, semi-elliptical surface flaw in contrast to the observed flaws which are subsurface with a maximum size of 0.165-inch deep by 0.5-inch long.

The maximum crack growth and applied stress intensity factor for the normal and upset conditions were found to occur in the nozzle belt region. The maximum crack growth, considering all the normal and upset condition transients for 48 EFPY, was determined to be 0.180-inch, which results in a final flaw depth of 0.533-inch. The maximum applied stress intensity factor for the normal and upset condition results in a fracture toughness margin of 3.6 which is greater than the IWB-3612 acceptance criterion of 3.16.

The maximum applied stress intensity factor for the emergency and faulted conditions occurs in the closure head to head flange region and the fracture toughness margin was determined to be 2.24, which is greater than the IWB-3612 acceptance criterion of 1.41. It is therefore concluded that the postulated intergranular separations in the Oconee Unit 1, 2, and 3 reactor vessel 508 Class 2 forgings are acceptable for continued safe operation through the period of extended operation.

5.4.3 Reactor Vessel Internals

Duke actively participated in a B&W Owners Group effort that developed a series of topical reports whose purpose was to demonstrate that the aging effects for reactor coolant system components and component groups are adequately managed for the period of extended operation for license renewal. One of the B&W Owners Group topical reports that was submitted and is currently under NRC review is BAW-2248 [Reference 5.4-29]which addresses the reactor vessel internals. Time-limited aging analyses applicable to the three Oconee reactor vessel internals are addressed within BAW-2248.

Time-limited aging analyses that are applicable to the Oconee reactor vessel internals include: (1) flow-induced vibration endurance limit assumptions; (2) transient cycle count assumptions for the replacement bolting; and (3) reduction in fracture toughness.

For license renewal, the *Reactor Vessel Internals Aging Management Program* will assure that appropriate action is taken in a timely manner to assure continued validity of the design of the Reactor Vessel Internals. This program is discussed in Chapter 4 of OLRP-1001.

5.4.4 Reactor Coolant Pump Flywheel

The reactor coolant pump 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 reactor coolant pumps was 500 motor starts over forty years. The aging effect of concern is fatigue crack initiation in the flywheel bore key way from stresses due to starting the motor [Reference 5.4-5, Section 5.4.4.2]. Therefore, this topic is considered to be a time-limited aging analysis for license renewal.

The 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 on average a pump start every 2.1 days. This conservative design is considered to be valid for the period of extended operation.

For license renewal, the effects of aging on the integrity of the reactor coolant pump flywheel will be adequately managed by the *Reactor Coolant Pump Flywheel Inspection Program*, Oconee Improved Technical Specification 5.5.8.

5.4.5 References for Section 5.4

5.4-1. BAW-2243A, *Demonstration of the Management of Aging Effects for the Reactor Coolant System Piping,* The B&W Owners Group Generic License Renewal Program, June 1996.

5.4-2. BAW-2244A, *Demonstration of the Management of Aging Effects for the Pressurizer,* The B&W Owners Group Generic License Renewal Program, December 1997.

5.4-3. D. M. Crutchfield (NRC) letter dated March 21, 1996 to Don Croneberger (BWOG/GLRP), Acceptance for Referencing of Topical Report BAW-2243, "Demonstration of the Management of Aging Effect for the Reactor Coolant System Piping."

5.4-4. C. I. Grimes (NRC) letter dated November 26, 1997 to D. J. Firth (BWOG/GLRP/FTI), Clarification in the Final Safety Evaluation Report for BAW-2244, *Demonstration of the Management of Aging Effects for the Pressurizer.*

5.4-5. *Oconee Nuclear Station Updated Final Safety Analysis Report,* as revised.

5.4-6. L.A. Wiens (NRC) letter dated April 27, 1995 to J.W. Hampton (Duke), *Fatigue Analyses for Reactor Coolant Pressure Boundary Attachment Piping* (TAC Nos. M90156, M90157 and M90158).

5.4-7. J.W. Hampton (Duke) letter dated June 26, 1995 to Document Control Desk (NRC), Oconee Nuclear Station, Docket Nos. 50-269, -270, *RCS Auxiliary Piping Fatigue Analysis Issue.*

5.4-8. L.A. Wiens (NRC) letter dated July 10, 1995 to J.W. Hampton (Duke), Oconee Nuclear Station, Docket Nos. 50-269, -270, -287, *Reactor Coolant System (RCS) Auxiliary Piping Fatigue Analysis Schedule.*

5.4-9. EPRI Report TR-103844*PWR Reactor Coolant System License Renewal Industry Report;* Revision 1, , July 1994.

5.4-10. BAW-2127, Bratcher, K.F., D.E. Costa, G.L. Weatherly, *Plant-specific Analysis in Response to Nuclear Regulatory Commission Bulletin 88-11, 'Pressurizer Surge Line Thermal Stratification'*, December 1993.

5.4-11. J.T. Larkins (NRC) letter dated May 18, 1990 to M.A. Haghi (B&WOG Materials Committee), Evaluation of Babcock & Wilcox Owners Group Bounding Analysis Regarding NRC Bulletin No. 88-11, *Pressurizer Surge Line Thermal Stratification*.

5.4-12. J.W. Hampton (Duke) letter dated May 17, 1994 to the Document Control Desk (NRC), Oconee Nuclear Station, Unit 1, Docket Nos. 50-269, - 270, - 287, Response to NRC Bulletin 88-11, *Pressurizer Surge Line Thermal Stratification, dated December 20, 1988, Supplementary Information.*

5.4-13. H.B. Tucker (Duke) letter dated December 29, 1989 to the Document Control Desk, Oconee Nuclear Station, Dockets Nos. 50-269, - 270 - 287, *Thermal Stresses in Piping Connected to Reactor Cooling System (NRC Bulletin 88-08).*

5.4-14. L.A. Reyes (NRC) letter dated August 27, 1997 to W.R. McCollum (Duke), *Notice of Violation and Proposed Imposition of Civil Penalties* - $330,000 (NRC Inspection Report nos. 50-269, 270, and 287/97-07, and 50-269, 270, and 287/97-08).

5.4-15. W.R. McCollum (Duke) letter dated September 25, 1997 to J. Lieberman (NRC) Oconee Nuclear Station, Docket Nos. 50-269, 50-270, 50-287, *Reply to Notice of Violation and Proposed Imposition of Civil Penalty*.

5.4-16. W. R. McCollum (Duke) letter dated February 26, 1998 to Document Control Desk (NRC), *Response to NRC Bulletin 88-08, Supplement 1,* Oconee Nuclear Station, Docket Nos. 50 -270, -287.

5.4-17. Title 10 Code of Federal Regulations, *§50.55a, Codes and Standards,* U. S. Nuclear Regulatory Commission.

5.4-18. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel*, The B&W Owners Group Generic License Renewal Program, June 1996.

5.4-19. BAW-2202, *Fracture Toughness Characterization of WF-70 Weld Metal*, B&W Nuclear Service Company, Lynchburg, VA, September 1993.

5.4-20. BAW-10046A, Revision 2, *Methods of Compliance With Fracture Toughness and Operational Requirements of 10 CFR 50, Appendix G*, B&W Nuclear Power Division/Alliance Research Center, June 1986.

5.4-21. BAW-1820, *177-Fuel Assembly Reactor Vessel and Surveillance Program Materials Information*, B&W Nuclear Power Division, Lynchburg, VA, December 1984.

5.4-22. BAW-2121P, *Chemical Composition of B&W Fabricated Reactor Vessel Beltline Welds*, B&W Nuclear Technologies, Inc., Lynchburg, VA, April 1991.

5.4-23. BAW-2166, *Response to Generic Letter 92-01,* B&W Nuclear Service Company, Lynchburg, VA, June 1992.

5.4-24. BAW-2222, *Response to Closure Letters to Generic Letter 92-01, Revision 1,* B&W Nuclear Technologies, Lynchburg, VA, June 1994.

5.4-25. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June 1998).

5.4-26. BAW-2275, T. Wiger and D. Killian, *Low Upper-Shelf Toughness Fracture Mechanics Analysis of B&W Designed Reactor Vessels for 48 EFPY*, Framatome Technologies, Inc. Lynchburg, VA.

5.4-27. BAW-2274, A. Nana, *Fracture Mechanics Analysis of Postulated Underclad Cracks in B&W Designed Reactor Vessels for 48 EFPY*, Framatome Technologies, Inc. Lynchburg, VA.

5.4-28. U.S. Atomic Energy commission, *Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components*, Regulatory Guide 1.43, May 1973.

5.4-29. BAW-2248, *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals,* The B&W Owners Group Generic License Renewal Program, July 1997.

Table 5.4-1 Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 1

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AHR 54	ZV-2861	A 508 Cl. 2	0.16	0.65	+3	119.3	1.11E+18	52.2	70.7	126.0	270
Intermediate Shell Plate	C2197-2	C2197-2	SA-302 Gr. BM*	0.15	0.50	+1	104.5	1.18E+19	109.3	63.6	174.0	270
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. BM*	0.10	0.50	+1	65.0	1.31E+19	69.9	63.6	134.5	270
Upper Shell Plate	C3278-1	C3278-1	SA-302 Gr. BM*	0.12	0.60	+1	83.0	1.31E+19	89.2	63.6	153.9	270
Lower Shell Plate	C2800-1	C2800-1	SA-302 Gr. BM*	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
Lower Shell Plate	C2800-2	C2800-2	SA-302 Gr. BM*	0.11	0.63	+1	74.5	1.31E+19	80.0	63.6	144.7	270
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	157.4	1.11E+18	69.0	68.5	132.4	300
IS Longit. Weld (Both 100%)	SA-1073	1P0962	ASA/Linde 80	0.21	0.64	-5	170.6	9.24E+18	166.8	68.5	[230.3]	270
IS to US Circ. Weld (ID 61%)	SA-1229	71249	ASA/Linde 80	0.23	0.59	+10	167.6	1.19E+19	175.7	56.0	241.7	300
US Longit. Weld (Both 100%)	SA-1493	8T1762	ASA/Linde 80	0.19	0.55	-5	149.3	1.12E+19	154.0	68.5	217.4	270
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	158.0	1.27E+19	168.5	68.5	232.0	300
LS Longit. Weld (100%)	SA-1426	8T1762	ASA/Linde 80	0.19	0.55	-5	149.3	1.08E+19	152.5	68.5	215.9	270
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.19	0.55	-5	149.3	1.08E+19	152.5	68.5	215.9	270
10 CFR 50.61 (Surveillance Data)												
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	133.0	1.11E+18	58.3	48.3	101.6	300
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	151.8	1.27E+19	161.9	48.3	205.2	300

Table 5.4-2 Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 2

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm^2 Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	AMX 77	123T382	A 508 Cl. 2	0.13	0.76	+3	95.0	1.19E+19	99.6	70.7	173.3	270
Upper Shell Forging	AAW 163	3P2359	A 508 Cl. 2	0.04	0.75	+20	26.0	1.28E+19	27.8	27.8	75.6	270
Lower Shell Forging	AWG 164	4P1885	A 508 Cl. 2	0.02	0.80	+20	20.0	1.27E+19	21.3	21.3	62.7	270
LNB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.28	0.59	-5	185.7	1.19E+19	194.7	68.5	258.1	300
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.34	0.68	-5	220.6	1.23E+19	233.3	68.5	296.8	300
10 CFR 50.61 (Surveillance Data)												
Upper Shell Forging	AAW 163	3P2359	A 508 Cl. 2	0.04	0.75	+20	8.9	1.28E+19	9.5	9.5	39.0	270
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.34	0.68	-5	223.7	1.23E+19	236.6	68.5	[300.1]	300

Table 5.4-3 Evaluation of Reactor Vessel Pressurized Thermal Shock Toughness Properties at 48 EFPY - Oconee Unit 3

Material Description				Chemical Composition								
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type	Cu wt%	Ni wt%	Initial RT_{NDT}	Chemistry Factor	Fluence, n/cm² Inside Surface	ΔRT_{NDT}, F at 48 EFPY	Margin	RT_{PTS}, F at 48 EFPY	Screening Criteria
10 CFR 50.61 (Tables)												
Lower Nozzle Belt Forging	4680	4680	A 508 Cl. 2	0.13	0.91	+3	96.0	1.14E+19	99.5	70.7	173.2	270
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	20.0	1.26E+19	21.3	21.3	82.6	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	20.0	1.26E+19	21.3	21.3	82.6	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.25	0.63	-5	181.0	1.14E+19	187.6	68.5	251.0	300
US to LS Circ. Weld (ID 75%)	WF-67	72442	ASA/Linde 80	0.26	0.60	-5	180.0	1.22E+19	190.0	68.5	[253.5]	300
10 CFR 50.61 (Surveillance Data)												
Upper Shell Forging	AWS 192	522314	A 508 Cl. 2	0.01	0.73	+40	47.4	1.26E+19	50.5	34.0	124.5	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	32.5	1.26E+19	34.6	17.0	91.6	270

Table 5.4-4 Evaluation of Reactor Vessel Extended Life (48EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 1

Material Description				Copper Composition w/o	Initial CvUSE, ft-lbs	48 EFPY Fluence T/4 Location, n/cm^2	Estimated 48 EFPY CvUSE at T/4	48 EFPY % Drop at T/4
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type					
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	AHR-54	ZV-2861	A508 Cl.2	0.16	109	9.18E+17	94	14
Intermediate Shell Plate	C2197-2	C2197-2	SA-302 Gr. B M	0.15	81	6.22E+18	63	22
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. B M	0.10	108	7.06E+18	90	17
Upper Shell Plate	C3278-1	C3278-1	SA-302 Gr. B M	0.12	81	7.06E+18	66	19
Lower Shell Plate	C2800-1	C2800-1	SA-302 Gr. B M	0.11	81	6.78E+18	66	18
Lower Shell Plate	C2800-2	C2800-2	SA-302 Gr. B M	0.11	119	6.78E+18	98	18
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.25	70	9.18E+17	55	22
IS Longit. Weld (Both 100%)	SA-1073	1P0962	ASA/Linde 80	0.21	70	4.91E+18	50	29
IS to US Circ. Weld (61% ID)	SA-1229	71249	ASA/Linde 80	0.26	70	6.22E+18	45	36
IS to US Circ. Weld (39% OD)	WF-25	299L44	ASA/Linde 80	0.35	70	-----	--	--
US Longit. Weld (Both 100%)	SA-1493	8T1762	ASA/Linde 80	0.20	70	5.66E+18	49	30
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.21	70	6.78E+18	48	32
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.20	70	5.71E+18	49	30
LS Longit. Weld (100%)	SA-1426	8T1762	ASA/Linde 80	0.20	70	5.71E+18	49	30
LS to Dutch. Circ. Weld (100%)	WF-9	72445	ASA/Linde 80	0.21	70	3.95E+16	64	9
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Plate	C3265-1	C3265-1	SA-302 Gr. B M	0.10	108	7.06E+18	91	16
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.25	70	9.18E+17	53	24
IS to US Circ. Weld (61% ID)	SA-1229	71249	ASA/Linde 80	0.26	70	6.22E+18	47	33
IS to US Circ. Weld (39% OD)	WF-25	299L44	ASA/Linde 80	0.35	70	-----	--	--
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.21	70	6.78E+18	48	31
LS to Dutch. Circ. Weld (100%)	WF-9	72445	ASA/Linde 80	0.21	70	3.95E+16	64	9

Table 5.4-5 Evaluation of Reactor Vessel Extended Life (48 EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 2

Material Description				Copper Composition w/o	Initial CvUSE, ft-lbs	48 EFPY Fluence T/4 Location, n/cm^2	Estimated 48 EFPY CvUSE at T/4	48 EFPY % Drop at T/4
Reactor Vessel Beltline Region Location	Matl. Ident.	Heat Number	Type					
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	AMX-77	123T382	A508 Cl.2	0.06	109	6.83E+18	94	14
Upper Shell Forging	AAW-163	3P2359	A508 Cl.2	0.04	133	7.78E+18	117	12
Lower Shell Forging	AWG-164	4P1885	A508 Cl.2	0.02	138	7.45E+18	124	10
LNB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.31	70	6.83E+18	42	40
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.35	70	7.45E+18	41	41
LS to Dutch. Circ. Weld (100%)	WF-112	406L44	ASA/Linde 80	0.31	70	4.36E+16	62	12
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Forging	AAW-163	3P2359	A508 Cl.2	0.04	133	7.78E+18	116	13
NB to US Circ. Weld (100%)	WF-154	406L44	ASA/Linde 80	0.31	70	6.83E+18	45	36
US to LS Circ. Weld (100%)	WF-25	299L44	ASA/Linde 80	0.35	70	7.45E+18	44	37
LS to Dutch. Circ. Weld (100%)	WF-112	406L44	ASA/Linde 80	0.31	70	4.36E+16	62	11

Table 5.4-6 Evaluation of Reactor Vessel Extended Life (48 EFPY) Charpy V-Notch Upper-Shelf Energy - Oconee Unit 3

Material Description				Copper Composition w/o	Initial CvUSE, ft-lbs	48 EFPY Fluence T/4 Location, n/cm^2	Estimated 48 EFPY CvUSE at T/4	48 EFPY % Drop at T/4
Reactor Vessel Beltline Region Location	**Matl. Ident.**	**Heat Number**	**Type**					
Regulatory Guide 1.99, Revision 2, Position 1								
Lower Nozzle Belt Forging	4680	4680	A508 Cl.2	0.13	109	6.66E+18	87	20
Upper Shell Forging	AWS-192	522314	A508 Cl.2	0.01	112	7.56E+18	102	9
Lower Shell Forging	ANK-191	522194	A508 Cl.2	0.02	144	7.28E+18	130	10
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	70	6.66E+18	46	35
US to LS Circ. Weld (75% ID)	WF-67	72442	ASA/Linde 80	0.24	70	7.28E+18	46	35
US to LS Circ. Weld (25% OD)	WF-70	72105	ASA/Linde 80	0.35	70	-----	--	--
LS to Dutch. Circ. Weld (100%)	WF-169-1	8T1554	ASA/Linde 80	0.18	70	4.23E+16	64	9
Regulatory Guide 1.99, Revision 2, Position 2								
Upper Shell Forging	AWS-192	522314	A508 Cl.2	0.01	112	7.56E+18	95	15
Lower Shell Forging	ANK-191	522194	A508 Cl.2	0.02	144	7.28E+18	111	23
NB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	70	6.66E+18	55	21
US to LS Circ. Weld (25% OD)	WF-70	72105	ASA/Linde 80	0.35	70	-----	--	--

5.5 TIME-LIMITED AGING ANALYSES FOR MECHANICAL COMPONENTS

5.5.1 MECHANICAL COMPONENT THERMAL FATIGUE

Thermal fatigue of mechanical systems is considered to be a time-limited aging analysis because all six of the criteria contained in §54.3 are satisfied. Thermal fatigue is considered to be an effect of aging and involves time-limited assumptions defined by the current term (e.g., 7000 cycles). Thermal fatigue is relevant in making a safety determination and involves conclusions related to the capability of the component to perform its intended function. The mechanical system design requirements are contained in the applicable design Code of Record which is given in Table 2.5-1 of OLRP-1001 and are thus considered to be part of the current licensing basis. The Reactor Coolant System components are addressed in Section 5.4. This section addresses the remaining mechanical systems falling within the scope of license renewal.

As background, Oconee has a number systems within the scope of license renewal that were designed to USAS B31.7 Class II and Class III, USAS B31.1.0, ASME Section III Subsection ND and ANSI B31.1 requirements. Piping systems designed to these requirements include a stress range reduction factor to provide conservatism in the design to account for cyclic conditions due to operations. The stress range reduction factor is 1.0 as long as the location does not exceed 7000 full temperature thermal cycles during its operation.

In order to identify the specific locations where extended operation could invalidate the existing stress range reduction factor in the piping analysis, an engineering review process was developed that considered the design temperatures and operating conditions of these Oconee mechanical systems. These mechanical systems were reviewed to determine which ones would be likely to see 7000 equivalent full temperature thermal cycles during plant operations. Results of this engineering review determined that analyses for all locations based on assumptions of less than 7000 cycles (22,000 cycles for the pressurizer sample line) are valid for the period of extended operation.

For license renewal, the existing analysis addressing thermal fatigue of the mechanical components within the scope of license renewal is considered to be valid for the period of extended operation.

5.6 TIME-LIMITED AGING ANALYSES FOR ELECTRICAL EQUIPMENT

The environmental qualification evaluations of electrical equipment [Footnote 18] are identified as time-limited aging analyses for Oconee by reviewing correspondence on the Oconee dockets, the Oconee UFSAR [Reference 5.6-1, Section 3.11], and Oconee engineering documents. In 1979, the NRC issued I.E. Bulletin 79-01B. Subsequently, NRC incorporated the requirements to environmentally qualify electrical equipment into §50.49, *Environmental qualification of electric equipment important to safety for nuclear power plants*. The Oconee *Environmental Qualification Program* includes the identification of all electrical equipment that is included within the program as well as the qualification records. Based on a review of the documentation, Duke identified electrical equipment that has a qualified life of at least 40 years. The qualified life establishes the time period for which assurance is provided that the electrical equipment can perform its function under postulated harsh environmental conditions resulting from a loss of coolant accident or a high energy line break inside the Reactor Building and a high energy line break outside the Reactor Building [Reference 5.6-1, Section 3.11]. The environmental qualification evaluations of electrical equipment are considered to be time-limited aging analysis for Oconee because all of the criteria contained in §54.3 are met.

The Oconee environmental qualification records have been evaluated for operation of Oconee during the period of extended operation. The results of time-limited aging analysis evaluations for electrical equipment are presented in Sections 5.6.1 through 5.6.33. [Footnote 19]

The Oconee *Environmental Qualification Program* is an effective program to manage the electrical equipment within the bounds of these time-limited aging analyses. The Oconee *Environmental Qualification Program* provides assurance that:

- All electrical equipment within the Oconee *Environmental Qualification Program* has a qualified life based on the component materials of construction, service environment, and testing, and
- All electrical equipment in the Oconee *Environmental Qualification Program* is replaced prior to the expiration of its qualified life.

18. Use of the phrase “electrical equipment” is consistent with the Environmental Qualification rule (§50.49) and is intended to be equivalent to the phrase “electrical component.”
19. GSI 168, which concerns Environmental Qualification of electrical components, is addressed in Section 1.5.3 of OLRP-1001.

The *Environmental Qualification Program* is implemented and maintained in accordance with the *Duke Quality Assurance Program.*

5.6.1 Accelerometers, TEC Monitor

TEC monitor accelerometers are used in the Pressure Operated Relief Valve Acoustical Monitoring System. TEC monitor accelerometers are age insensitive. The qualification analyses of the TEC monitor accelerometers remains valid for the period of extended operation.

5.6.2 Actuators, Limitorque

Limitorque Actuators are used in all areas of Oconee Nuclear Station. An analysis of the qualified life was completed using actual ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. Limitorque Actuators are qualified for both inside containment and outside containment. Both of these applications are included in this analysis.

5.6.2.1 Thermal Analysis Summary

Inside containment Limitorque Actuators are qualified to the equivalent of 135 years at an average ambient temperature of 140°F (60°C). The bounding average ambient temperature is 135.67°F (57.59°C). The bounding application temperature is less than the qualified ambient temperature.

Outside containment Limitorque Actuators are qualified to the equivalent of 60 years at an average ambient temperature of 137.96°F (58.87°C). The bounding average inside containment ambient temperature is 122°F (50°C). The bounding application temperature is less than the qualified temperature.

5.6.2.2 Radiation Analysis Summary

Inside containment Limitorque Actuators are qualified to 2.04E8 rads. The bounding inside containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

Outside containment Limitorque Actuators are qualified to 2.0E8 rads. The bounding outside containment 60-year total integrated dose (normal dose plus LOCA dose) is 7.0E6 rads. The bounding total integrated dose is less than the qualified dose for these actuators.

5.6.2.3 Conclusion

Limitorque Actuators are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.3 Actuators, Rotork

Rotork Actuators have a 40-year qualified life. No plans exist to extend the qualified life of Rotork Actuators and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.4 Cables, Anaconda EPR/Hypalon & EPR/Neoprene

Anaconda EPR/Hypalon and EPR/Neoprene cables are used extensively throughout Oconee Nuclear Station in motor operated valve and solenoid valve applications. The bounding EQ application for Anaconda EPR/Hypalon and EPR/Neoprene cables was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Anaconda EPR/Hypalon and EPR/Neoprene cables.

5.6.4.1 Thermal Analysis Summary

Anaconda EPR/Hypalon and EPR/Neoprene cables are qualified for a 40-year life at 181.4°F (83°C). The bounding cable conductor temperature (ambient temperature plus self-heating temperature rise) is 124.93°F (51.63°C). At 124.93°F (51.63°C), the qualified life of Anaconda EPR/Hypalon and EPR/Neoprene cables is greater than 60 years.

5.6.4.2 Radiation Analysis Summary

Anaconda EPR/Hypalon and EPR/Neoprene cables are qualified to 2.0E8 rads. The bounding containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.4.3 Conclusion

Anaconda EPR/Hypalon and EPR/Neoprene cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.5 Cables, BIW CSPE

BIW CSPE cables are used throughout Oconee Nuclear Station in instrumentation applications. The bounding EQ application for BIW CSPE cables was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of BIW CSPE cables.

5.6.5.1 Thermal Analysis Summary

BIW CSPE cables are qualified to 40 years at 131°F (55°C). Self-heating temperature rise is insignificant for BIW CSPE cable applications. The bounding average ambient temperature is 120°F (48.89°C). At 120°F (48.89°C), the qualified life of BIW CSPE cables is greater than 60 years.

5.6.5.2 Radiation Analysis Summary

BIW CSPE cables are qualified to 1.14E8 rads. The bounding 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.5.3 Conclusion

BIW CSPE cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.6 Cables, Brand-Rex & Samuel Moore PVC

Brand-Rex and Samuel Moore PVC cables are used outside the Reactor Building at in instrumentation and ASCO solenoid valve applications. The bounding EQ application was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Brand-Rex and Samuel Moore PVC cables.

5.6.6.1 Thermal Analysis Summary

Brand-Rex and Samuel Moore PVC cables are qualified to 40 years at 140°F (60°C). Self-heating temperature rise is insignificant for Brand-Rex and Samuel Moore PVC cable applications. The bounding average ambient temperature of the Penetration Rooms is 108°F (42.22°C). At 108°F (42.22°C), the qualified life of Brand-Rex and Samuel Moore PVC cables is greater than 60 years.

5.6.6.2 Radiation Analysis Summary

Brand-Rex PVC cables are qualified to 8.26E7 rads and Samuel Moore PVC cables are qualified to 5.0E6 rads. The bounding Penetration Room 60-year total integrated dose (normal dose plus LOCA dose) is 3.6E6 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.6.3 Conclusion

Brand-Rex and Samuel Moore PVC cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.7 Cables, Brand-Rex Flame Retardant XLPE

Brand-Rex flame retardant XLPE insulated instrumentation cable is used in solenoid valve applications in the Auxiliary Building Penetration Rooms. The bounding EQ application for Brand-Rex flame retardant XLPE cables was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Brand-Rex flame retardant XLPE cables.

5.6.7.1 Thermal Analysis Summary

Brand-Rex flame retardant XLPE cables are qualified for 40 years at 161.6°F (72°C). Self-heating temperature rise is insignificant for Brand-Rex flame retardant XLPE cable applications. The bounding average ambient temperature of the Penetration Rooms is 108°F (42.22°C). At 108°F (42.22°C), the qualified life of Brand-Rex flame retardant XLPE cables is greater than 60 years.

5.6.7.2 Radiation Analysis Summary

Brand-Rex flame retardant XLPE cables are qualified to 2.1E8 rads. The bounding Penetration Room 60-year total integrated dose (normal dose plus LOCA dose) is 3.6E6 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.7.3 Conclusion

Brand-Rex flame retardant XLPE cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.8 Cables, ITT Suprenant & Raychem Cross-linked Polyalkene Hook-up Wire

ITT Surprenant and Raychem cross-linked polyalkene (MIL W-81044) hook-up wire is used outside the Reactor Building at in various applications. The bounding EQ application for ITT Surprenant and Raychem cross-linked polyalkene hook-up wire was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of ITT Surprenant and Raychem cross-linked polyalkene hook-up wire.

5.6.8.1 Thermal Analysis Summary

ITT Surprenant and Raychem cross-linked polyalkene hook-up wire is rated for 40 years at a continuous operating temperature of 302°F (150°C). Self-heating temperature rise is insignificant for ITT Surprenant and Raychem cross-linked polyalkene hook-up wire applications. The bounding ambient temperature is 122°F (50°C). At 122°F (50°C), the qualified life of ITT Surprenant and Raychem cross-linked polyalkene hook-up wire is greater than 60 years.

5.6.8.2 Radiation Analysis Summary

ITT Surprenant and Raychem cross-linked polyalkene hook-up wire is qualified to 2.0E8 rads. The bounding outside-containment 60-year total integrated dose (normal dose plus LOCA dose) is 7.5E6 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.8.3 Conclusion

ITT Surprenant and Raychem cross-linked polyalkene hook-up wire are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.9 Cables, Kerite-HTK

Kerite-HTK cables are only used on the Reactor Building cooling unit fan motors. The bounding EQ application for Kerite-HTK cables was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Kerite-HTK cables.

5.6.9.1 Thermal Analysis Summary

Kerite-HTK cables are rated for 60 years at a continuous operating temperature of 169.59°F (76.44°C). The bounding application conductor temperature (ambient temperature plus self-heating temperature rise) is 146.14°F (63.41°C). The bounding application temperature is less than the qualified temperature.

5.6.9.2 Radiation Analysis Summary

Kerite-HTK cables are qualified to 2.0E8 rads. The bounding containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.9.3 Conclusion

Kerite-HTK cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.10 Cables, Okonite EPR/Neoprene

Okonite EPR/Neoprene cables are used extensively throughout Oconee Nuclear Station in EQ and non-EQ applications. The bounding EQ application for Okonite EPR/Neoprene cables was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Okonite EPR/Neoprene cables.

5.6.10.1 Thermal Analysis Summary

Okonite EPR/Neoprene cables are qualified for 40 years at 194°F (90°C). The bounding conductor temperature (ambient temperature plus self-heating temperature rise) is 157.87°F (69.93°C). At 157.87°F (69.93°C), the qualified life of Okonite EPR/Neoprene cables is greater than 60 years.

5.6.10.2 Radiation Analysis Summary

Okonite EPR/Neoprene cables are qualified to 2.0E8 rads. The bounding containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.10.3 Conclusion

Okonite EPR/Neoprene cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.11 Cables, Samuel Moore EPDM/Hypalon

Samuel Moore EPDM/Hypalon cables are used in instrumentation applications inside the Reactor Buildings and in the Penetration Rooms. The bounding EQ application was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Samuel Moore EPDM/Hypalon cables.

5.6.11.1 Thermal Analysis Summary

Samuel Moore EPDM/Hypalon cables are qualified for 40 years at 127°F (52.78°C). Self-heating temperature rise is insignificant for Samuel Moore EPDM/Hypalon cable applications. The bounding average ambient temperature of the Penetration Rooms for all three units is 108°F (42.22°C). The bounding application temperature in the Reactor Buildings (located in the basement) is 90°F (32.22°C). At both 108°F (42.22°C) and 90°F (32.22°C), the qualified life of Samuel Moore EPDM/Hypalon cables is greater than 60 years.

5.6.11.2 Radiation Analysis Summary

Samuel Moore EPDM/Hypalon cables are qualified to 2.0E8 rads. The bounding Penetration Room 60-year total integrated dose (normal dose plus LOCA dose) is 3.6E6 rads. The bounding inside-containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose for the Penetration Rooms and inside-Containment are less than the qualified dose for these cables.

5.6.11.3 Conclusion

Samuel Moore EPDM/Hypalon cables are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.12 Connection & Sealing Assemblies, Scotchcast 9 And Swagelok Quick-Connect Assemblies

Scotchcast 9 and Swagelok quick-connect assemblies are used on motor-operated valves, solenoid valves, limit switches, and transmitters. The bounding EQ application was determined and an analysis of the qualified life was completed using ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Scotchcast 9 and Swagelok quick-connect assemblies.

5.6.12.1 Thermal Analysis Summary

ScotchCast 9 and Swagelok quick-connect assemblies are qualified for 40 years at 140°F (60°C). Self-heating temperature rise is insignificant for ScotchCast 9 and Swagelok quick-connect assembly applications. The bounding average ambient temperature for all three units is 129°F (53.89°C). At 129°F (53.89°C), the qualified life of ScotchCast 9 and Swagelok quick-connect assemblies is greater than 60 years.

5.6.12.2 Radiation Analysis Summary

ScotchCast 9 and Swagelok quick-connect assemblies are qualified to 2.2E8 rads. The bounding inside-containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these assemblies.

5.6.12.3 Conclusion

ScotchCast 9 and Swagelok quick-connect assemblies are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.13 Heat Shrink Tubing, Raychem NCBK Nuclear Cable Breakout Splice Assemblies

Raychem NCBK nuclear cable breakout splice assemblies are used extensively throughout Oconee Nuclear Station in all types of applications. The bounding EQ application was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Raychem NCBK nuclear cable breakout splice assemblies.

5.6.13.1 Thermal Analysis Summary

Raychem NCBK nuclear cable breakout splice assemblies without an overall sleeve are qualified for 40 years at 167°F (75°C). The bounding application temperature (ambient temperature plus self-heating temperature rise) is 140°F (60°C). At 140°F (60°C), the qualified life of Raychem NCBK nuclear cable breakout splice assemblies is greater than 60 years.

5.6.13.2 Radiation Analysis Summary

Raychem NCBK nuclear cable breakout splice assemblies are qualified to 2.0E8 rads. The bounding inside containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose for these cables.

5.6.13.3 Conclusion

Raychem NCBK nuclear cable breakout splice assemblies are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.14 Heat Shrink Tubing, Raychem NPKV Nuclear Plant Stub Connection Kit

Raychem NPKV nuclear plant stub connection kits are used extensively throughout Oconee Nuclear Station in all types of applications. The bounding EQ application was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Raychem NPKV nuclear plant stub connection kits.

5.6.14.1 Thermal Analysis Summary

Raychem NPKV nuclear plant stub connection kits are qualified for 42.8 years at 194°F (90°C). The bounding stub connection temperature (ambient temperature plus self-heating temperature rise) is 140°F (60°C). At 140°F (60°C), the qualified life of Raychem NPKV nuclear plant stub connection kits is greater than 60 years.

5.6.14.2 Radiation Analysis Summary

Raychem NPKV nuclear plant stub connection kits are qualified to 2.0E8 rads. The bounding inside containment 60-year total integrated dose (normal plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

5.6.14.3 Conclusion

Raychem NPKV nuclear plant stub connection kits are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.15 Heat Shrink Tubing, Raychem WCSF-N In-line Splice Assemblies

Raychem WCSF-N in-line splice assemblies are used extensively throughout Oconee Nuclear Station in all types of applications. The bounding EQ application was determined and an analysis of the qualified life was completed using actual temperature rise and ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Raychem WCSF-N in-line splice assemblies.

5.6.15.1 Thermal Analysis Summary

Raychem WCSF-N in-line splice assemblies are qualified for 44.2 years at 194°F (90°C). The bounding application conductor temperature (ambient temperature plus self-heating temperature rise) is 157.87°F (69.93°C). At 157.87°F (69.93°C), Raychem WCSF-N in-line splice assemblies have a qualified life greater than 60 years.

5.6.15.2 Radiation Analysis Summary

Raychem WCSF-N in-line splice assemblies are qualified to 2.20E8 rads. The bounding inside-containment 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

5.6.15.3 Conclusion

As required by §54.21(c)(1), calculation OSC-7058 demonstrates that Raychem WCSF-N in-line splice assemblies used in EQ applications are qualified in excess of 60 years; i.e., through the period of extended operation.

5.6.16 Heat Shrink Tubing, EGS Grayboots

EGS Grayboots were initially installed in 1994 with a qualified 40-year qualified life. No plans exist to extend the qualified life of EGS Grayboots and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.17 Heat Shrink Tubing, EGS Connectors

EGS Connectors were initially installed in April 1993 with a qualified 40-year life. No plans exist to extend the qualified life of EGS Connectors and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.18 Motors, Joy/Reliance

Joy/Reliance Motors have a 40-year qualified life. No plans exist to extend the qualified life of Joy/Reliance Motors and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.19 Motors, Louis-Allis

Louis-Allis Motors have a 40-year qualified life. No plans exist to extend the qualified life of Louis-Allis Motors and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.20 Motors, Reliance

Reliance Motors were initially installed in 1994 with a 40-year qualified life. No plans exist to extend the qualified life of Reliance Motors and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.21 MOTORS, WESTINGHOUSE

5.6.21.1 Westinghouse Reactor Building Spray Pump Motors

Westinghouse Reactor Building spray pump motors have a 40-year qualified life. No plans exist to extend the qualified life of Westinghouse Reactor Building spray pump motors and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.21.2 Westinghouse High Pressure Injection Pump & Low Pressure Injection Pump Motors

Westinghouse high pressure injection pump and low pressure injection pump motor operating parameters were determined and an analysis of the qualified life was performed using actual ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years.

5.6.21.2.1 THERMAL ANALYSIS SUMMARY

Westinghouse high pressure injection pump and low pressure injection pump motors are qualified for 40 years at 221°F (105°C). The bounding high pressure injection pump motor stator temperature (combination of ambient temperature and self-heating temperature rise) is 176.31°F (80.17°C). The bounding low pressure injection pump motor stator temperature (combination of ambient temperature and self-heating temperature rise) is 202.66°F (94.81°C). At both 176.31°F (80.17°C) and 202.66°F (94.81°C), these Westinghouse pump motors are qualified for greater than 60 years.

5.6.21.2.2 RADIATION ANALYSIS SUMMARY

Westinghouse HPI and LPI pump motors are qualified to 2.0E8 rads. The bounding 60-year total integrated dose (normal dose plus LOCA dose) is 3.95E6 rads. The bounding total integrated dose is less than the qualified dose.

5.6.21.2.3 CONCLUSION

Westinghouse high pressure injection pump and low pressure injection pump motors are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.22 Penetration Assemblies, Conax

Conax electrical penetration assemblies are used in the Reactor Buildings. The bounding EQ application was determined and an analysis of the qualified life was completed using actual ambient condition parameters, including radiation, to demonstrate a qualified life through a period of extended operation. This bounding application is used to envelope all other applications of Conax electrical penetration assemblies.

5.6.22.1 Thermal Analysis Summary

Conax electrical penetration assemblies were initially installed in April 1986. The bounding ambient temperature is 124.32°F (51.29°C). At 124.32°F (51.29°C), the qualified life of Conax electrical penetrations is 56.8 years which will extend beyond the end of the period of extended operation.

5.6.22.2 Radiation Analysis Summary

Conax electrical penetrations are qualified to 1.71E8 rads. The bounding Reactor Building 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

5.6.22.3 Conclusion

Conax electrical penetration assemblies are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.23 Penetration Assemblies, D. G. O'Brian

D. G. O'Brian electrical penetration assemblies are used in the containment structures. The bounding application was determined and an analysis of the qualified life was completed using actual ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of D. G. O'Brian electrical penetration assemblies.

5.6.23.1 Thermal Analysis Summary

The bounding service temperature (ambient temperature plus self-heating temperature rise) is 174°F (78.89°C). At 174°F (78.89°C), the qualified life of D. G. O'Brian electrical penetration assemblies is greater than 60 years.

5.6.23.2 Radiation Analysis Summary

D. G. O'Brian electrical penetrations installed at Oconee Nuclear Station are qualified to 1.03E8 rads and similar D. G. O'Brian electrical penetration assemblies used at McGuire and Catawba Nuclear Stations are qualified to 2.0E8 rads. The bounding containment

60-year total integrated dose (normal plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

5.6.23.3 Conclusion

D. G. O'Brian electrical penetration assemblies are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.24 Penetration Assemblies, Viking

Viking electrical penetration assemblies are used extensively on all three units. An analysis of qualified life (temperature and radiation) is performed in the vendor documentation. The thermal and radiation values contained in the vendor qualification documentation are compared to the Viking electrical penetration assembly service conditions.

5.6.24.1 Thermal Analysis Summary

The Viking electrical penetration assembly vendor qualification demonstrates a qualified life of 62 years at 120°F (48.89°C) ambient which includes self-heating temperature rise. The actual yearly average ambient temperature for the penetration assemblies at the highest installed elevation in the Reactor Buildings is 102°F (38.89°C). The penetration assembly current rating is significantly derated from that used for vendor qualification and the 18°F difference envelopes the actual self-heating temperature rise.

5.6.24.2 Radiation Analysis Summary

The vendor qualification demonstrates that Viking electrical penetration assemblies are qualified to 1.2E8 rads. The bounding Reactor Building 60-year total integrated dose (normal dose plus LOCA dose) is 1.06E8 rads. The bounding total integrated dose is less than the qualified dose.

5.6.24.3 Conclusion

The Viking electrical penetration assembly vendor qualification remains valid for the period of extended operation.

5.6.25 RTD, Conax

Conax RTDs were initially installed in September 1991 with a qualified 40-year life. No plans exist to extend the qualified life of Conax RTDs and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.26 RTD, Rosemount

Rosemount RTDs are constructed with all inorganic materials with the exception of the o-ring supplied with the manufacturer's head. The manufacturer's supplied head and o-ring are not used for EQ applications of Rosemount RTDs at Oconee Nuclear Station so all installed Rosemount RTDs have no organic materials. With no organic materials, the existing analyses remain valid for the period of extended operation.

5.6.27 RTD, Weed

Weed RTDs were initially installed in September 1991 with a 40-year qualified life. No plans exist to extend the qualified life of Weed RTDs and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.28 Solenoid Valves, Valcor

Valcor solenoid valves were installed after 1993 with a qualified 40-year life. No plans exist to extend the qualified life of Valcor solenoid valves and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.29 Switches, Barton/Westinghouse

Barton/Westinghouse switches were initially installed in 1986 with a 40-year qualified life. No plans exist to extend the qualified life of Barton/Westinghouse switches and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.30 Terminal Blocks, States & Stanwick

States and Stanwick terminal blocks are used in solenoid valve circuits and are located in the Penetration Rooms. The bounding EQ application for States and Stanwick terminal blocks was determined and an analysis of the qualified life was completed using ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of States and Stanwick terminal blocks.

5.6.30.1 Thermal Analysis Summary

States and Stanwick terminal blocks are qualified for 40 years at 221°F (105°C). Self-heating temperature rise is insignificant for States and Stanwick terminal block applications. The bounding average ambient temperature of the Penetration Rooms for all three units is 108°F (42.22°C). At 108°F (42.22°C), the qualified life of States and Stanwick terminal blocks is greater than 60 years.

5.6.30.2 Radiation Analysis Summary

States and Stanwick terminal blocks are qualified to 3.0E7 rads. The bounding Penetration Room 60-year total integrated dose (normal dose plus LOCA dose) is 1.79E6 rads. The bounding total integrated dose is less than the qualified dose for these terminal blocks.

5.6.30.3 Conclusion

States and Stanwick terminal blocks are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.31 TRANSMITTERS, GEMS DELAVAL

Gems Delaval level transmitters have a 40-year qualified life. No plans exist to extend the qualified life of Gems Delaval level transmitters and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.32 TRANSMITTERS, BARTON MODEL 764

Barton model 764 transmitters are used as Reactor Building pressure transmitters and are located in the Penetration Rooms. The bounding EQ application was determined and an analysis of the qualified life was completed using ambient condition parameters, including radiation, to demonstrate a qualified life in excess of 60 years. This bounding application is used to envelope all other applications of Barton model 764 transmitters.

5.6.32.1 Thermal Analysis Summary

Barton model 764 transmitters are qualified for 40 years at 122°F (50°C). Self-heating temperature rise is insignificant for Barton model 764 transmitters. The bounding average ambient temperature of the Penetration Rooms for all three units is 108°F (42.22°C). At 108°F (42.22°C), the qualified life of Barton model 764 transmitters is greater than 60 years.

5.6.32.2 Radiation Analysis Summary

Barton model 764 transmitters are qualified to 2.0E8 rads. The bounding Penetration Room 60-year total integrated dose (normal dose plus LOCA dose) is 1.79E6 rads. The bounding total integrated dose is less than the qualified dose for these transmitters.

5.6.32.3 Conclusion

Barton model 764 transmitters are qualified for applicable bounding thermal and radiation environments to the end of the period of extended operation.

5.6.33 Transmitters, Rosemount

Rosemount transmitters have a 40-year qualified life. No plans exist to extend the qualified life of Rosemount transmitters and they are not analyzed for license renewal. The Oconee Environmental Qualification Program will ensure the effects of aging on the intended functions will be adequately managed for the period of extended operation.

5.6.34 References for Section 5.6

5.6-1. *Oconee Nuclear Station, Updated Final Safety Analysis Report,* as revised.

5.7 TIME-LIMITED AGING ANALYSES FOR STRUCTURES & STRUCTURAL COMPONENTS

5.7.1 POLAR CRANE

The load cycle limit of the Oconee Polar Cranes has been identified as a time-limited aging analysis by reviewing correspondence on the Oconee dockets associated with the control of heavy loads. In 1981, NRC issued Generic Letter 81-07 and NUREG-0612 [Reference 5.7-1]. NRC issued a letter [Reference 5.7-2] requesting additional information which Duke responded to by letter [Reference 5.7-3]. One of the concerns expressed in NUREG-0612 was the potential for fatigue of the crane due to frequent loadings at or near design conditions. Cranes at Oconee 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 time-limited aging analysis for Oconee because the analysis meets all of the criteria contained in §54.3.

In the written response to NUREG-0612, Duke stated that the polar crane was the bounding Oconee crane for the lift of loads at or near rated capacity. Other cranes at Oconee at the time were considered to be bounded by the polar crane since the projected number of lifts of loads at or near capacity for the life of the plant were less than the number of projected lifts by the polar crane for the life of the plant. The number of lifts at or near the rated capacity of the polar crane over a 40 year life was estimated to be approximately 100. The estimated number of lifts at or near capacity of the polar crane 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 is to remove the reactor vessel head at the beginning of refueling and the second lift is to replace it on the reactor vessel at the end of refueling. The number of lifts is conservative because Duke now projects fewer refueling outages through the remaining licensed life of Oconee because refueling occurs approximately once every 18 months instead of annually.

The NRC evaluated the written Duke response to NUREG-0612 and in its evaluation [Reference 5.7-4] stated that since the number of cycles is far below the 20,000 loading cycles specified by CMAA-70 [Reference 5.7-5], fatigue is not a concern at Oconee. Duke notes that even for operation of the Oconee polar cranes through 60 years, the estimated number of heavy load cycles of the polar crane remains below 20,000 loading cycles.

Subsequent to the above NUREG-0612 review, Oconee installed an Independent Spent Fuel Storage Installation (ISFSI) which became operational in 1990. The operation of the ISFSI resulted in additional lifts by the spent fuel pool cranes near their rated lifting capacity. Spent fuel pool cranes lift near their rated capacity when they are lifting full spent fuel casks. For each cask, the crane makes two full lifts:

(1) moving from the support frame to the decon pit and
(2) moving from the decon pit to the transfer car.

The ISFSI is currently licensed for 88 casks which equates to 176 full lifts over the life of the plant. Because the NUHOMS-24P canisters in the Oconee ISFSI are assumed to be non-transportable, they will be returned to the spent fuel pool so that the spent fuel can be removed and repackaged into multi-purpose canisters. Repackaging will result in three full lifts per cask:

(1) moving the canisters from the transfer car to the pool;
(2) moving the canisters from the support frame to the decon pit; and
(3) moving the canisters from the decon pit to the car.

This repackaging will result in an additional 264 full lifts for the 88 casks and a total of 440 full load lifts of one spent fuel pool crane for the 88 casks. This value is conservative because all lifts are assigned to one spent fuel pool crane rather than dividing the lifts between the two Oconee spent fuel pool cranes. The estimate of the number of heavy load lifts of the spent fuel pool cranes requires assumptions associated with the date when the high level waste repository is licensed and capable of accepting spent fuel. Current estimates are that this will not occur until late in the current licensed term of Oconee. Duke estimates that an additional 123 casks would be needed to store spent fuel onsite through 2013 and to completely empty the pools. Each cask will require two full lifts to initially load each cask and then three full lifts to repackage each cask for shipment. These casks could be multi-purpose 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 1055 lifts on one spent fuel crane for the current operating term. Extending this estimate through 2034 still results in a number of estimated heavy lifts below the threshold of 20,000 cycles from CMAA-70.

For license renewal, the existing analyses addressing heavy load lifts of both the polar cranes and the spent fuel pool cranes are considered to be valid for the period of extended operation.

5.7.2 Spent Fuel Rack Boraflex

High density poison spent fuel storage racks were installed in the Oconee Unit 1 & 2 spent fuel pool in 1981 and in the Oconee Unit 3 spent fuel pool in 1984. The NRC approved the installation of these racks by amendments to the Oconee operating license [References 5.7-6 & 5.7-7]. The spent fuel storage racks contain Boraflex, which is the trade name for a silicon polymer that contains a specified amount of Boron 10 that is used as the neutron absorber to assure that the design basis for criticality control is met through the service life of the racks. The Boraflex is affixed to each of the four exterior sides of the fuel storage cell by means of stainless steel wrappers. Boraflex is used in spent fuel storage racks for the nonproductive absorption of neutrons such that the NRC established acceptance criterion of k_{eff} no greater than 0.95 is maintained.

Testing of Boraflex was performed by the manufacturer prior to installation. These tests subjected Boraflex specimens to high levels of gamma radiation with the specimens immersed in borated water. These test results indicated that under irradiation, Boraflex loses elasticity and becomes brittle at high levels of exposure and that no significant degradation should occur for a normal service life of 40 years. In the NRC Safety Evaluations approving the use of these racks, the NRC concluded that 'tests under irradiation and at elevated temperatures in borated water indicate that the Boraflex material will not undergo significant degradation during the expected service life of 40 years.' Based on the above information, Duke has conservatively determined that the aging of Boraflex meets the criteria of §54.3 and should be considered as a time-limited aging analysis for the purposes of license renewal.

At the time of initial installation, Duke implemented a *Boraflex Monitoring Program* to provide assurance that no unexpected corrosion or degradation of the Boraflex materials would compromise the criticality analysis in support of the design of spent fuel storage racks. Surveillance specimens, which are in the form of removable stainless steel clad Boraflex sheets, were removed after approximately five years and examined to determine their physical condition after installation. Since the initial implementation of the program, it has been modified to require additional testing and inspections of the spent fuel storage racks based on experience at Oconee as well as in the industry.

Blackness testing was performed at Oconee on the spent fuel storage racks in 1991. In the Unit 1 and 2 pool, a total of 33 Boraflex panels in 9 storage cells were examined. No detectable gaps were observed from the standard scan. In the Unit 3 pool, a total of 34 Boraflex panels in 9 storage cells were examined and again there were no detectable gaps observed from the standard scan. Future in-situ examinations at Oconee are contingent upon the results of a no-Boraflex analyses. If continued operation of the Boraflex is required, the need/schedule for future examinations will be based on RACKLIFE predictions for the Oconee pools, the extent to which Boraflex is relied upon in the analysis, and other relevant testing results.

In 1996 as a result of industry-wide experience with the degradation of Boraflex, NRC issued Generic Letter 96-04 [Reference 5.7-8] which provides descriptions of several industry experiences to date and a discussion of relevant experimental data from test programs. The staff stated that on the basis of test and surveillance information from plants that have detected areas of Boraflex degradation, no safety concern exists that warrants immediate action. In issuing Generic Letter 96-04, the staff requested that all licensees with installed spent fuel pool storage racks containing the neutron absorber Boraflex provide an assessment of the physical condition of the Boraflex.

The Duke response to this request was provided by Reference 5.7-9 and supplemented by Reference 5.7-10. The response indicated, in part, that Duke had acquired the RACKLIFE computer code which had been developed by the Electric Power Research Institute for the purpose of assessing overall Boraflex thinning based upon cumulative gamma exposure, storage rack design parameters, and dissolved silica concentration in the spent fuel pool. The Oconee spent fuel storage racks are being analyzed, taking reduced or no credit for Boraflex. Future Boraflex verification activities will depend upon the extent to which Boraflex is relied upon in the analysis, as well as the RACKLIFE assessment, and plans for future verification will be developed accordingly.

Oconee has had in place a *Boraflex Monitoring Program* since the installation of the high density spent fuel storage racks containing Boraflex. This program contains several elements including testing, monitoring, and analysis of the criticality design. Actions are taken as necessary to assure that the NRC established acceptance criterion of k_{eff} no greater than 0.95 is maintained.

For license renewal, the continuation of the *Boraflex Monitoring Program* will provide reasonable assurance that the capability of the Boraflex to nonproductively absorb neutrons such that k_{eff} is maintained no greater than 0.95 will continue to be adequately managed for the period of extended operation.

5.7.3 References for Section 5.7

5.7-1. Generic Letter 81-07, *NUREG-0612, Control of Heavy Loads,* NRC, February 3, 1981.

5.7-2. J. F. Stolz (NRC) to W. O. Parker (Duke) letter dated February 18, 1982, Oconee Nuclear Station, Docket Numbers 50-269, 50-270, 50-287.

5.7-3. W. O. Parker (Duke) letter to Document Control Desk (NRC) dated October 8, 1982, Oconee Nuclear Station, Docket Numbers 50-269, 50-270, 50-287.

5.7-4. J. F. Stolz (NRC) letter H. B. Tucker (Duke) dated April 20, 1983, Oconee Nuclear Station, Docket Numbers 50-269, 50-270, 50-287.

5.7-5. Crane Manufacturers Association of America (CMAA) Specification #70, *Specifications for Electric Overhead Traveling Cranes,* Revised 1975.

5.7-6. R. W. Reid (NRC) letter to W. O. Parker (Duke) dated December 24, 1980, License Amendments 90, 90, and 87 for License Nos. DPR-38, DPR-47 and DPR-55 for Oconee Nuclear Station, Docket Nos. 50-269, 50-270, and 50-287.

5.7-7. J. F. Stolz (NRC) letter to H. B. Tucker (Duke) dated September 29, 1983, License Amendments 123, 123, and 120 for License Nos. DPR-38, DPR-47 and DPR-55 for Oconee Nuclear Station, Docket Nos. 50-269, 50-270, and 50-287.

5.7-8. NRC Generic Letter 96-04, *Boraflex Degradation in Spent Fuel Pool Storage Racks*, June 26, 1996.

5.7-9. M. S. Tuckman (Duke) letter to Document Control Desk (NRC) dated October 22, 1996, *Response to Generic letter 96-04, Boraflex Degradation in Spent Fuel Storage Racks*, Oconee Nuclear Station, Docket Nos. 50-269, 50-270, and 50-287.

5.7-10. M. S. Tuckman (Duke) letter to Document Control Desk (NRC) dated December 22, 1997, *Response to Generic letter 96-04, Boraflex Degradation in Spent Fuel Storage Racks*, Oconee Nuclear Station, Docket Nos. 50-269, 50-270, and 50-287.