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A Duke Energy Company

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March 27, 2000

Document Control Desk
U. S. Nuclear Regulatory Commission
Washington, DC 20555

Subject: License Renewal
UFSAR Supplement, March 2000
Oconee Nuclear Station
Docket Nos. 50-269, -270, -287

By letter dated July 6, 1998, Duke Energy Corporation (Duke) submitted an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application). Exhibit B of the Application contained the initial Updated Final Safety Analysis Report (UFSAR) Supplement required by 10 CFR §54.21(d). During the review of the Oconee Application, the NRC staff requested that Duke provide a current version of the UFSAR Supplement reflecting revisions resulting from the staff's review of the Application. As discussed during a meeting held with the staff on December 9, 1999, Duke agreed to revise the initial UFSAR Supplement and to submit the revised version by April 1, 2000.

Consistent with that agreement, please find attached the "Oconee Nuclear Station, UFSAR Supplement, March 2000," which contains information from the initial UFSAR Supplement, as further revised by (1) license renewal-related commitments and changes submitted on the Oconee Nuclear Station dockets since July 1998, and (2) changes made in response to the NRC staff letter dated March 15, 2000.

If there are any questions regarding the contents of this submittal, please contact Bob Gill at 704-382-3339.

Very truly yours,

W. R. McCollum Jr., ~~Site~~ Vice President
Oconee Nuclear Station

w/Attachment

A037

Oconee Nuclear Station

UFSAR Supplement

March 2000

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W. R. McCollum, Jr., being duly sworn, states that he is Vice President, Oconee Nuclear Station, Duke Energy Corporation, that he is authorized on the part of said Company to sign and file with the U. S. Nuclear Regulatory Commission the attached UFSAR Supplement; and that all statements and matters set forth herein are true and correct to the best of his knowledge and belief. To the extent that these statements are not based on his personal knowledge, they are based on information provided by Duke employees and/or consultants. Such information has been reviewed in accordance with Duke Energy Corporation practice and is believed to be reliable.

W. R. McCollum, Jr., Vice president
Oconee Nuclear Site

Subscribed and sworn to before me this 27 day of March 2000.

Connie M. Breazale
Notary Public

My Commission Expires:

2/13/2003

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Oconee Nuclear Station

UFSAR Supplement

March 2000

UFSAR Supplement

Changes to Chapters 3, 4, 5, 6, and 9

Revise existing text in UFSAR Section 3.2.2.2 to read as follows:

3.2.2.2 System Piping Classifications

Oconee has a number of systems that were designed to USAS B31.7 Class II and Class III and to USAS B31.1.0 requirements [Reference Table 3-1]. Piping analyses for these systems include stress range reduction factors to provide conservatism in the design to account for thermal cyclic operations. Thermal fatigue of mechanical systems designed to USAS B31.7 Class II and Class III and to USAS B31.1 is considered to be a time-limited aging analysis because all six of the criteria contained in §54.3 are satisfied.

From the license renewal review, it was determined that the existing analyses of thermal fatigue of these mechanical systems are valid for the period of extended operation.

Add the following References:

Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

Revise existing text in UFSAR Section 3.8.1.5.2 to read as follows:

3.8.1.5.2 Prestress Losses

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 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.

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.

Containment post-tensioning system surveillance will be performed in accordance with Oconee Improved Technical Specification SR 3.6.1.2. 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 provides the required prescribed lower limits and minimum required values in Appendix 16.6-2, Figures 1, 2, and 3. 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.

From the license renewal review, it was determined that the loss of prestress analysis is valid for the period of extended operation and will continue to be managed by the Containment Inservice Inspection Plan.

Add the following References:

Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

Revise existing text concerning fatigue loads in UFSAR Section 3.8.1.5.3 to read as follows:

3.8.1.5.3 Liner Plate

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 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. The number of cycles for this loading is 40 cycles for the plant life of 40 years.

(b) The combined loading of thermal cycling due to Reactor Building interior temperature varying during the startup and shutdown of the Reactor Coolant System and Type A integrated leak rate tests required by 10 CFR 50, Appendix J, including any Type A tests that may be performed if major modifications or repairs are made to the Containment pressure boundary. The number of cycles for this combined 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.

From the license renewal review, it was determined that the existing analyses of thermal fatigue for the Containment penetrations are valid for the period of extended operation.

Add the following References:

Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

Revise existing text in UFSAR Section 3.11, to read as follows:

(Text that has been added is underlined; text that has been revised is ~~strikethrough~~)

3.11 ENVIRONMENTAL DESIGN OF MECHANICAL AND ELECTRICAL EQUIPMENT

3.11.1 EQUIPMENT IDENTIFICATION AND ENVIRONMENTAL CONDITIONS

Duke has a program in place for environmental qualification of safety-related electrical equipment inclusive of equipment required to achieve a safe shutdown. Environmental effects resulting from the postulated design basis accidents documented in Chapter 15, "Accident Analyses" have been considered in the qualification of electrical equipment which is covered by this program. This program has been reviewed and approved by NRC (Reference 2).

3.11.1.1 Equipment Identification

Safety-related electrical equipment that is required to perform a safety function(s) in a postulated harsh environment is identified in Duke Power Company's response to NRC IE Bulletin 79-01B (Reference 1).

Safety-related mechanical equipment including design information is identified in Section 3.2.2, "System Quality Group Classification."

3.11.1.2 Environmental Conditions

The postulated harsh environmental conditions resulting from a LOCA or HELB inside the Reactor Building and a HELB outside the Reactor Building are identified and discussed in Duke Power Company's response to NRC IE Bulletin 79-01B (Reference 1).

The environmental parameters that compose the overall worst-case containment environment are as follows:

Containment Temperature: Time history as shown in Figure 15-71 for the Design Basis Accident (DBA), a 5.0 ft^2 hot leg break.

Containment Pressure: Time history as shown in Figure 15-56 for the largest (14.1 ft^2) hot leg break.

Relative Humidity: 100%

Radiation: Total integrated radiation dose for the equipment location includes the 40 year normal operating dose plus the appropriate accident dose based on equipment operability requirements. The bases for determining the containment radiation environment are discussed in Chapter 12, "Radiation Protection."

Chemical Spray: Boric acid spray resulting from mixing in the containment sump with borated water from the borated water storage tank. Refer to Section 6.2.2, "Containment Heat Removal Systems" for additional information on chemical spray.

3.11.2 QUALIFICATION TEST AND ANALYSIS

Safety-related equipment identified in Section 3.11.1.1, "Equipment Identification" is qualified by test and/or analysis. The method of qualification for this Class 1E equipment is identified in Duke Power Company's response to NRC IE Bulletin 79-01B (Reference 1).

3.11.3 QUALIFICATION TEST RESULTS

The results of the qualification tests and/or analyses for the electrical equipment identified in Section 3.11.1.1, "Equipment Identification" are presented in the qualification documentation references identified in Duke Power Company's response to NRC IE Bulletin 79-01B (Reference 1). Additionally, a summary of the qualification results is also presented in the bulletin response.

3.11.4 EVALUATION FOR LICENSE RENEWAL

Some qualification analyses for safety-related equipment identified in Section 3.11.1.1 were found to be a time-limited aging analyses for license renewal. Evaluations were performed for applicable electrical equipment with the results submitted in Reference 3.

~~3.11.4~~ 3.11.5 LOSS OF VENTILATION

The control area air conditioning and ventilation systems (Section 9.4.1, "Control Room Ventilation") are conservatively designed to provide a suitable environment for the control and electrical equipment. In addition, redundant air conditioning and ventilation equipment is provided, as summarized below, to assure that no single failure of an active component within these systems will prevent proper control area environmental control.

1. Two 100 percent capacity supply fans with filter banks and chilled water coils.
2. Two 100 percent capacity chillers.
3. Two 50 percent capacity outside air booster fans.

The Station Blackout scenario involves a four hour loss of ventilation to the control area. Assuming the non-essential loads are manually stripped within the first 30 minutes of the event, and the initial ambient temperatures outlined in the Selected Licensee Commitments Manual, Section 16.8.1 are not exceeded, analysis has shown that the following temperatures would not be exceeded:

Control rooms	120°F
Cable rooms	137°F
Electrical equipment rooms	115°F
I&C Battery rooms	107°F

The above temperatures are within the specifications of the control room habitability requirements of 10CFR 50.63, and within the operating temperature limits of the equipment required to operate during the scenario.

~~3.11.5~~ 3.11.6 ESTIMATED CHEMICAL AND RADIATION ENVIRONMENT

The estimated chemical and radiation environments at Oconee are discussed in Duke Power Company's response to NRC IE Bulletin 79.01B (Reference 1). Additional information regarding chemical and radiation conditions is presented in Section 6.5, "Fission Product Removal and Control Systems" and in Chapter 12, "Radiation Protection," respectively.

~~3.11.6~~ 3.11.7 REFERENCES

1. Oconee Nuclear Station Response to IE Bulletin 79-OlB, as revised, including Response to NRC Equipment Qualification Safety Evaluation Report.

2. Letter from J. F. Stolz (NRC) to H. B. Tucker (Duke) dated March 20, 1985. Subject: Safety Evaluation Report on Environmental Qualification of Electrical Equipment Important to Safety.

3. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3*, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

4. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

Insert new UFSAR Section 3.12 to read as follows:

3.12 Cranes and Control of Heavy Loads

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 3.12-1]. NRC issued a letter [Reference 3.12-2] requesting additional information which Duke responded to by letter [Reference 3.12-3]. 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 meet all of the criteria contained in §54.3 [Reference 3.12-4].

From the license renewal review, the existing analyses addressing heavy load lifts of both the polar cranes and the spent fuel pool cranes were determined to be valid for the period of extended operation [Reference 3.12-5].

References for Section 3.12

3.12-1. Generic Letter 81-07, *NUREG-0612, Control of Heavy Loads,* NRC, February 3, 1981.

3.12-2. 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.

3.12-3. 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.

3.12-4 *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

3.12-5 NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

Revise existing text in UFSAR Section 4.5.1.2 to read as follows:

4.5.1 Reactor Vessel Internals

4.5.1.2 Design Bases

Duke actively participated in a B&W Owners Group effort that developed a series of technical 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 is BAW-2248A [Reference 4-1] which addresses the reactor vessel internals. Time-limited aging analyses applicable to the Oconee reactor vessel internals are addressed within BAW-2248A. This report was incorporated by reference onto the Oconee dockets [Reference 4-2].

Time-limited aging analyses applicable to the Oconee reactor vessel internals, along with the results of their review for license renewal, are as follows: (1) flow-induced vibration endurance limit assumptions - A review of the existing analysis showed conservatism in the original design, and no further action is needed in the period of extended operation to assure validity of the design; (2) transient cycle count assumptions for the replacement bolting - The ongoing programmatic actions under the Thermal Fatigue Management Program (See Section 5.2.1.4) will assure the validity of the design assumptions in the period of extended operation; and (3) reduction in fracture toughness - The actions developed as a part of the Reactor Vessel Internals Inspection (See Section 18.3.20) will assure the validity of the design assumptions in the period of extended operation. [Reference 4-3]

REFERENCES FOR CHAPTER 4

4-1. *Demonstration of the Management of Aging Effects for the Reactor Vessel Internals,* BAW-2248A, The B&W Owners Group Generic License Renewal Program, March 2000.

4-2. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

4-3 NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3,* Docket Nos. 50-269, 50-270, and 50-287.

Revise existing text in UFSAR Section 5.2.1.4 to read as follows:

5.2.1.4 Cyclic Loads

Oconee Technical Specification 5.5.6 establishes the requirement to provide controls to track the number of UFSAR Section 5.2.1.4 cyclic and transient occurrences to assure that components are maintained within design limits. This requirement is 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 provide reasonable assurance that the thermal fatigue analyses, including applicable flaw growth calculations, will remain valid or that appropriate action is taken in a timely manner to assure continued validity of the design.

References for this section: Application [Reference 5-1] and Final SER [Reference 5-2]

Insert New Section 5.2.x

5.2.x Leak Before Break

Leak-before-break is used at Oconee to establish Mark – B fuel assembly spacer grid impact loads and displacement time histories.

The successful application of Leak-Before-Break (LBB) to the Oconee Reactor Coolant System main coolant piping is described in B&WOG topical report entitled, "The B&W Owners Group Leak-Before-Break Evaluation of Margins Against Full Break for RCS Primary Piping of B&W Designed NSSS," BAW-1847, Revision 1, September 1985. This report provides the technical basis for evaluating postulated flaw growth in the main Reactor Coolant System piping under normal plus faulted loading conditions and was approved by the NRC for the current term of operation. The time-limited aging analyses in BAW-1847, Revision 1, include fatigue flaw growth and the qualitative assessment of thermal aging of cast austenitic stainless steel reactor coolant pump inlet and exit nozzles.

Fatigue flaw growth evaluations are based on transient definitions defined by the Reactor Coolant System design specification. The original transient cycles that were defined for 40 years of operation are being monitored by the Oconee *Thermal Fatigue Management Program.* If a transient cycle count approaches or exceeds the allowable design limit, corrective actions are taken. The cast austenitic stainless steel reactor coolant pump inlet and outlet nozzles are susceptible to thermal aging. Thermal aging of cast austenitic stainless steel causes a reduction of fracture toughness. Reduction of fracture toughness of the reactor coolant pump nozzles has been determined to be acceptable for the period of extended operation through a flaw stability analysis.

References for this section: [References 5-3 and 5-4]

Revise appropriate portions of text in UFSAR Section 5.2.3.3 to include the following:

5.2.3.3 Reactor Vessel

Replace existing text in Section 5.2.3.3.6 with the following:

5.2.3.3.6 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 there is a significant change 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.

Section 50.61(c) provides two methods for determining RT_{PTS}: (Position 1) for material that does not have credible surveillance data available, and (Position 2) for material that does have credible surveillance data. Availability of surveillance data is not the only measure of whether Position 2 [Footnote 1] may be used; the data must also meet tests of sufficiency and credibility.

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.

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 2] [Reference 5-5]. 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 5-6].

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1. The term "Position" is taken from Regulatory Guide 1.99, the methodology of which was incorporated into 10 CFR 50.61.

2. 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.

For Position 1 material (surveillance data not available), **ΔRT$_{NDT}$** 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 1][References 5-7, 5-8, 5-9, and 5-10]. The value of **CF** is directly obtained from tables in §50.61. **ff** is a calculated value [Footnote 2] 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 5-1 through 5-3.

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 **ffs**.

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

1. 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.

2. $ff = f^{(0.28-0.1*\log f)}$, where f = fluence*$10^{-19}$ (n/cm^2, E>1MeV).

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).

Section 50.61(b)(2) establishes screening criteria for RT_{PTS} : 270°F for plates, forgings, and axial welds and 300°F for circumferential welds. The values for RT_{PTS} at 48 EFPY are provided in Tables 5-1, 5-2, and 5-3 for Units 1, 2, and 3, respectively. The RT_{PTS} values reported herein are based on updated 48 EFPY fluence projections using the evaluation based methodology described in BAW-2251 [Reference 5-11, Appendix D] and BAW-2241P [Reference 5-12]. The chemistry and surveillance data for the beltline materials are reported in BAW-2325 [Reference 5-13].

The projected RT_{PTS} values for Units 1, 2 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 230.3°F (screening limit of 270°F). For Unit 2, the limiting weld is WF-25, with a projected value of RT_{PTS} at 48 EFPY of 296.8°F (screening limit of 300°F). For Unit 3, the limiting weld is WF-67 with a projected value of RT_{PTS} at 48 EFPY of 253.5°F (screening limit of 300°F). [Reference 5-14]

Reference for this section: Final SER [Reference 5-2].

Insert New Section 5.2.3.3.X

5.2.3.3.X 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 5-15], which is included in BAW-2251 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 credible surveillance data available and Position 2 for material that does have credible 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 and are reported in Tables 5-4 through 5-6. 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. 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 of margin of safety against fracture for the reactor vessels within the scope of this report for 48 EFPY.

Insert New Section 5.2.3.3.Y

5.2.3.3.Y 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 Atomic Energy Commission. [Footnote 1] 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 5-16] 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 5-17]. 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 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.

1. R. C. DeYoung (USAEC) to J. F. Mallay (B&W), letter transmitting topical report evaluation, October 11, 1972.

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.

Revise existing text in UFSAR Section 5.4.4.2 to read as follows:

5.4.4.2 Flywheel Design Consideration

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. 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 valid for the period of extended operation.

References for this section: Application [Reference 5-1] and Final SER Reference 5-2]

References for Chapter 5

5-1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

5-2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

5-3. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999, Response to Request For Additional Information, Attachment 1, Response to RAI 5.4.1-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

5-4. M. S. Tuckman (Duke) letter dated December 17, 1999, Response to NRC letter dated November 17, 1999, Attachment 1, page 26, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and –287.

5-5. BAW-2202, *Fracture Toughness Characterization of WF-70 Weld Metal,* B&W Nuclear Service Company, Lynchburg, VA, September 1993.

5-6. 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.

5-7. BAW-1820, *177-Fuel Assembly Reactor Vessel and Surveillance Program Materials Information,* B&W Nuclear Power Division, Lynchburg, VA, December 1984.

5-8. BAW-2121P, *Chemical Composition of B&W Fabricated Reactor Vessel Beltline Welds,* B&W Nuclear Technologies, Inc., Lynchburg, VA, April 1991.

5-9. BAW-2166, *Response to Generic Letter 92-01,* B&W Nuclear Service Company, Lynchburg, VA, June 1992.

5-10. BAW-2222, *Response to Closure Letters to Generic Letter 92-01, Revision 1,* B&W Nuclear Technologies, Lynchburg, VA, June 1994.

5-11. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel,* The B&W Owners Group Generic License Renewal Program, June 1996.

5-12. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997

5-13. BAW-2325, *Response to Request for Additional Information (RAI) Regarding Reactor Pressure Vessel Integrity,* Revision 1, January 1999.

5-14. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999, Response to Request For Additional Information, Attachment 1, Response to RAI 5.4.2-1, pages 78, 79, and 80; Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

5-15. 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.

5-16. 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.

5-17. U.S. Atomic Energy commission, *Control of Stainless Steel Weld Cladding of Low-Alloy Steel Components*, Regulatory Guide 1.43, May 1973.

Table 5 - 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	Mat'l. 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	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	0.57	-5	152.4	1.12E+19	157.3	68.5	220.8	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	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
LS Longit. Weld (100%)	SA-1430	8T1762	ASA/Linde 80	0.19	0.57	-5	152.4	1.08E+19	155.8	68.5	219.3	270
10 CFR 50.61 (Surveillance Data)												
LNB to IS Circ. Weld (100%)	SA-1135	61782	ASA/Linde 80	0.23	0.52	-5	141.1	1.11E+18	61.8	48.3	105.1	300
US to LS Circ. Weld (100%)	SA-1585	72445	ASA/Linde 80	0.22	0.54	-5	145.2	1.27E+19	155.8	48.3	199.1	300

* - SA-302 Grade B modified by ASME Code Case 1339

[ ]- Controlling value of RT_{PTS} reference temperature

Table 5 - 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	Mat'l. 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	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	0.27	0.59	-5	182.6	1.19E+19	191.5	68.5	255.0	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)												
None												

[ ]- Controlling value of RT_{PTS} reference temperature

Table 5 - 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/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	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	0.24	0.63	-5	178.0	1.14E+19	184.6	68.5	248.1	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	36.0	1.26E+19	38.3	34.0	75.5	270
Lower Shell Forging	ANK 191	522194	A 508 Cl. 2	0.02	0.76	+40	17.4	1.26E+19	18.5	17.0	112.3	270
LNB to US Circ. Weld (100%)	WF-200	821T44	ASA/Linde 80	0.24	0.63	-5	158.3	1.14E+19	159.5	48.3	202.8	300

[ ]- Controlling value of RT_{PTS} reference temperature

Table 5 - 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 - 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/cm²	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 - 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	-----	--	--

Insert new UFSAR Section 6.2.1.6 Coating Materials to read as follows:

The original coating materials applied to all structures within the containment during plant construction were qualified by withstanding autoclave tests designed to simulate LOCA conditions. The qualification testing of Service Level I substitute coatings now used for new applications or repair/replacement activities inside containment was in accordance with ANSI N 101.2 for LOCA conditions and radiation tolerance. The substitute coatings when used for maintenance over the original coatings were tested, with appropriate documentation, to demonstrate a qualified coating system.

The original, maintenance, and new coating systems defining surface preparation, type of coating, and dry film thickness are tabulated in Table 6-33 (Containment Coatings).

The elements of the Oconee Coatings Program are documented in a Nuclear Generation Department Directive. The Oconee Coatings Program includes periodic condition assessments of Service Level I coatings used inside containment. As localized areas of degraded coatings are identified, those areas are evaluated for repair or replacement, as necessary.

Add reference to Chapter 6.2:

M. S. Tuckman (Duke) letter dated November 11, 1998 to Document Control Desk (NRC), "Response to Generic Letter 98-04: Potential Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-of-Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment," Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and –287.

Insert new UFSAR Section 9.1.2.5 to read as follows:

9.1.2.5 Boraflex

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.

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.

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.

The *Spent Fuel Rack Boraflex Monitoring Program* monitors the Boraflex to assure that the required 5% criticality margin is maintained for the lifetime of the spent fuel storage racks. The program includes:

(1) Periodic neutron attenuation testing of a representative sample of actual Boraflex panel enclosures to established appropriate acceptance criteria;
(2) Periodic sampling and analysis for silica in the spent fuel cooling water and the trending of results obtained;
(3) Corrective actions to be taken in the event the Boraflex is no longer capable of maintaining the required subcriticality margin.

Data collection and analysis of Boraflex condition is implemented through Nuclear Generation Department administrative and workplace procedures.

From the license renewal review, it was determined that the above activities will effectively manage the Boraflex during the period of extended operation.

References for this section:

9-1 *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

9-2 NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

UFSAR Supplement

Changes to Chapter 16

Selected Licensee Commitments (SLCs)

Note: Selected Licensee Commitments are contained in the Oconee Selected Licensee Commitment Manual (SLC). The SLC Manual is Chapter 16.0 of the Oconee Updated Final Safety Analysis Report (UFSAR). This manual is intended to contain commitments that warrant higher control, but are not appropriate for inclusion into Technical Specifications.

Revise Figures 1, 2, and 3 of SLC 16.6.2 as follows:

16.6. COMMITMENTS RELATED TO ENGINEERED SAFETY FEATURES (NON-ESF SYSTEMS)

16.6.2 REACTOR BUILDING POST-TENSIONING SYSTEM

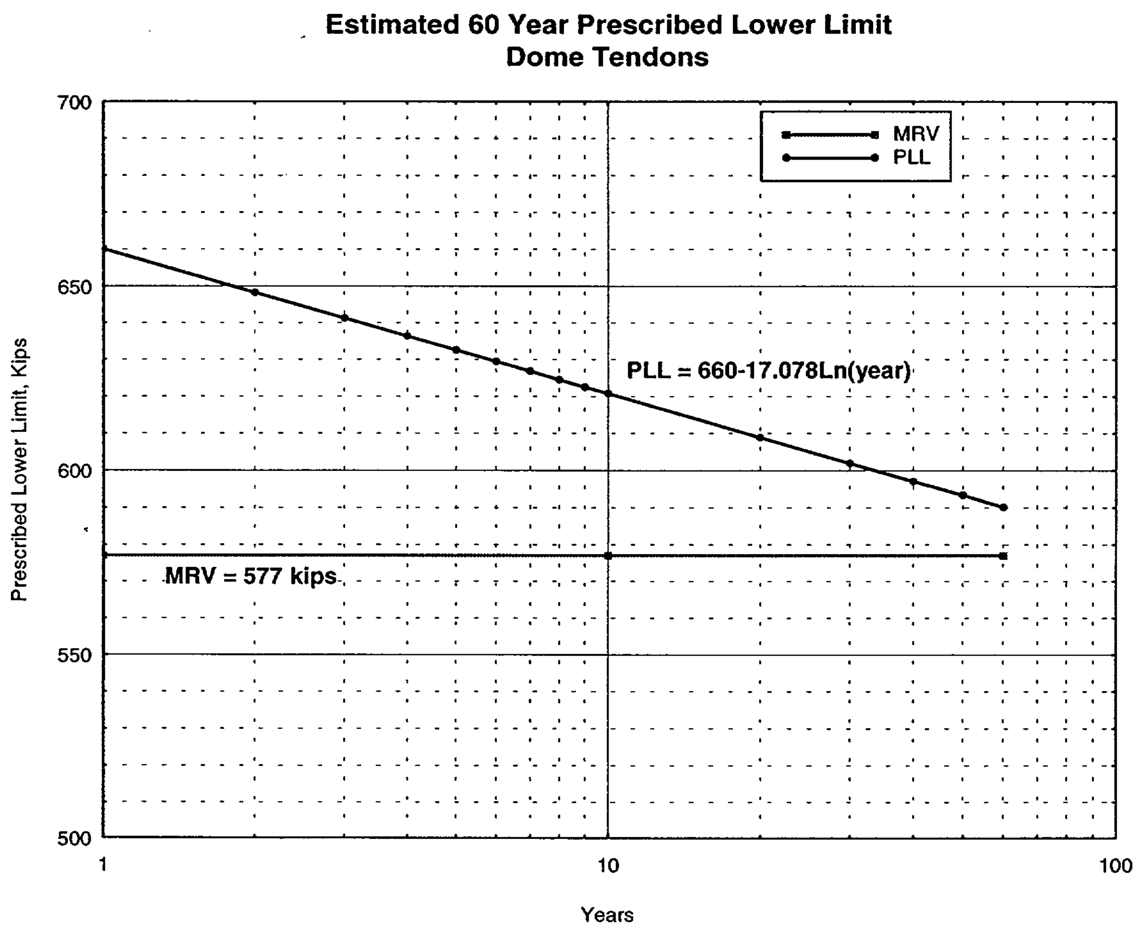
See next three pages.

Additional references for this section:

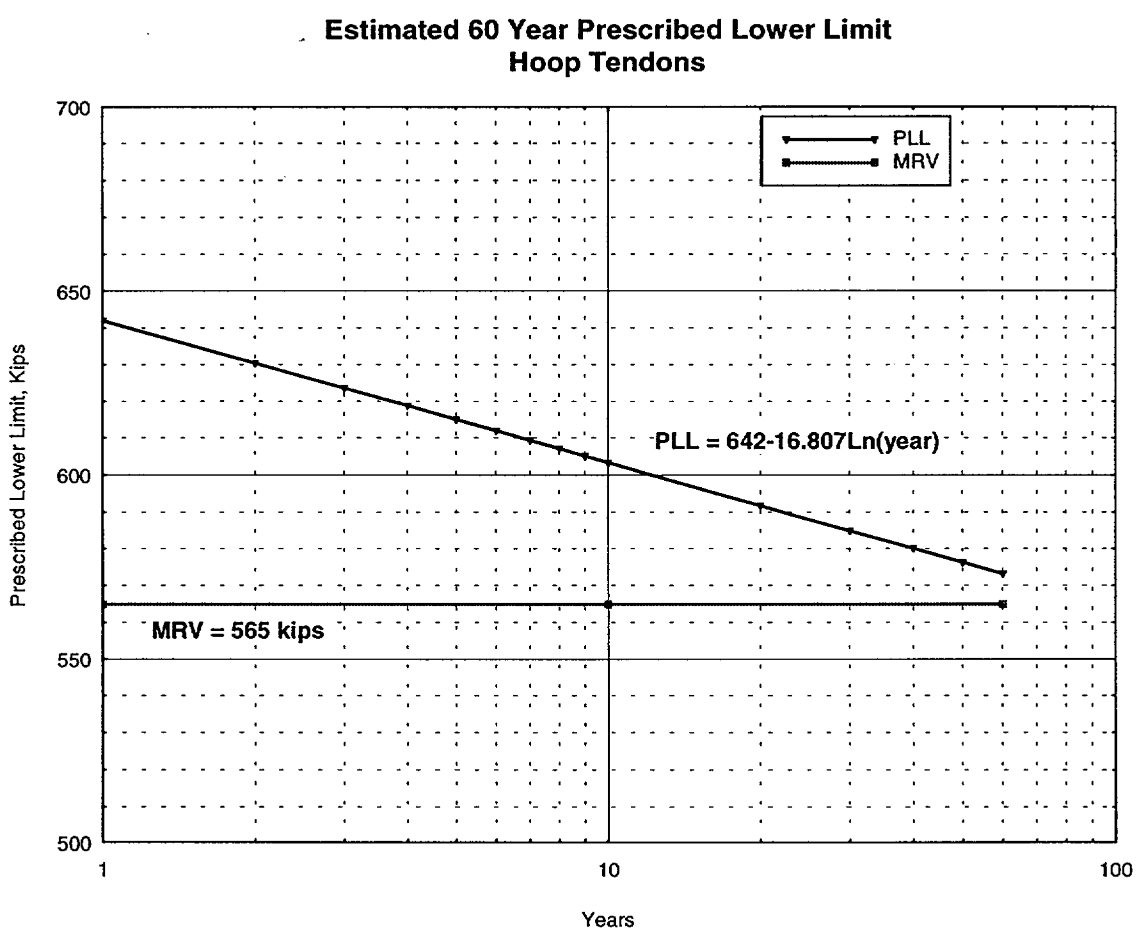
Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3, submitted by M. S. Tuckman (Duke) letter dated July 6, 1998 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station, Units 1, 2, and 3*, Docket Nos. 50-269, 50-270, and 50-287.

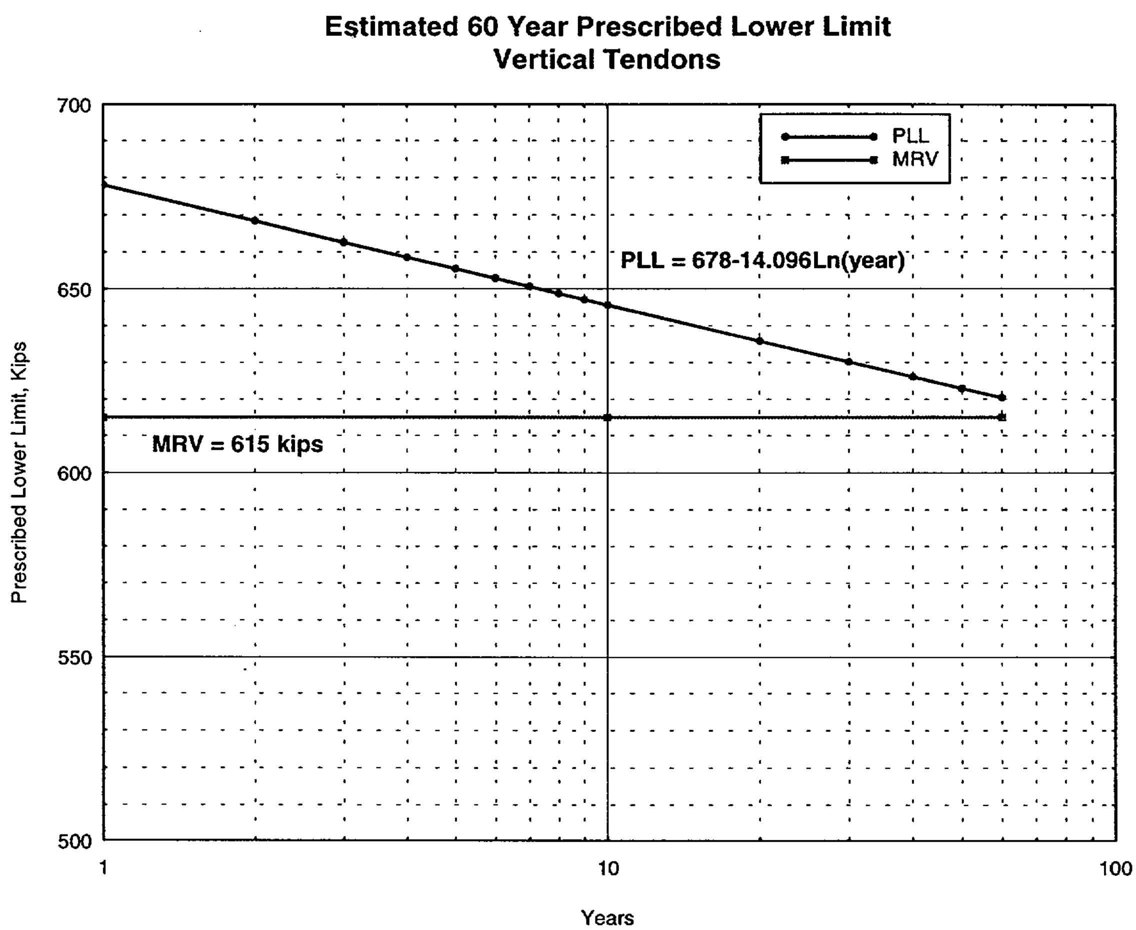
Appendix 16.6-2
Figure 1
Units 1, 2, and 3



Appendix 16.6-2
Figure 2
Units 1, 2, and 3



Appendix 16.6-2
Figure 3
Units 1, 2, and 3



UFSAR Supplement

New Chapter 18

Aging Management Programs and Activities

Insert new UFSAR Chapter 18 to read as follows:

18. AGING MANAGEMENT PROGRAMS AND ACTIVITIES

18.1 INTRODUCTION

As the current operating license holder for Oconee Nuclear Station, Duke Energy Corporation prepared an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application) [Reference 18-1]. The application including information provided in additional correspondence, provides sufficient information for the NRC to complete their technical and environmental reviews and provided the basis for the NRC to make the findings required by §54.29 (Final Safety Evaluation Report – Final SER) [Reference 18-2]. Pursuant to the requirements of §54.21(d), the UFSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by §54.21 (a) and (c), respectively.

As an aid to the reader, Table 18-1 provides a summary listing of the programs, activities and time-limited aging analyses (TLAA) (topics) required for license renewal. The first column of Table 18-1 provides an listing of these topics. The second column of Table 18-1 indicates whether the topic is a Program/Activity or TLAA. The third column of Table 18-1 identifies where the description of the Program, Activity, or TLAA is located in either the Oconee UFSAR or in the Oconee Improved Technical Specifications (ITS).

Section 18.2 contains summary descriptions of the one-time inspections that have been committed to be performed prior to the period of extended operation. Section 18.3 contains summary descriptions of the aging management programs and periodic inspections that are ongoing through the duration of the operating licenses of Oconee Nuclear Station. Section 18.4 contains additional commitments that are not identified in the preceding sections of Chapter 18.

Station documents will be established, implemented, and maintained to cover the aging management programs and activities described in Chapter 18.

Table 18-1 Summary Listing of the Programs, Activities and TLAA

Topic	*Program / Activity or TLAA*	*UFSAR / ITS Location*
Alloy 600 Aging Management Program	Program/ Activity	18.3.1
Battery Rack Inspections	Program/ Activity	ITS: SR 3.8.1.11, SR 3.8.3.3, SR 3.10.1.10
Cast Iron Selective Leaching Inspection	Program/ Activity	18.2.1
Chemistry Control Program	Program/ Activity	18.3.2 ITS: 5.5.14
Containment Inservice Inspection Plan	Program/ Activity	18.3.3
Containment Leak Rate Testing Program	Program/ Activity	ITS 5.5.2
Containment Liner Plate and Penetrations – Thermal Cycles	TLAA	3.8.1.5.3
Containment Post-Tensioning System -- Prestress Loss	TLAA	3.8.1.5.2, 16.6.2 18.3.3
Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program	Program/ Activity	18.3.4
Crane Inspection Program	Program/ Activity	18.3.5

Topic	*Program / Activity or TLAA*	*UFSAR / ITS Location*
Cranes and Control of Heavy Loads	TLAA	3.12
Duke Power Five-Year Underwater Inspection of Hydroelectric Dams and Appurtenances	Program/ Activity	18.3.6
Elevated Water Storage Tank Inspection	Program/ Activity	18.3.7
Environmental Qualification of Electrical Equipment	TLAA	3.11
Federal Energy Regulatory Commission (FERC) Five Year Inspections	Program/ Activity	18.3.8
Fire Protection Program	Program/ Activity	16.9.1, 16.9.2, 16.9.4, 16.9.5 18.3.17.8
Flow Accelerated Corrosion Program	Program/ Activity	18.3.9
Fluid Leak Management Program	Program/ Activity	18.3.10
Galvanic Susceptibility Inspection	Program/ Activity	18.2.2
Heat Exchanger Performance Testing Activities	Program/ Activity	18.3.11
Inservice Inspection Plan	Program/ Activity	18.3.12
Inspection Program for Civil Engineering Structures and Components	Program/ Activity	18.3.13

Topic	Program / Activity or TLAA	UFSAR / ITS Location
Insulated Cables and Connections Aging Management Program	Program/ Activity	18.3.14
Keowee Air and Gas Systems Inspection	Program/ Activity	18.2.3
Keowee Oil Sampling Program	Program/ Activity	18.3.15
Non-Class 1 Piping – Thermal Cycles	TLAA	3.2.2.2
Once Through Steam Generator Upper Lateral Support Inspection	Program/ Activity	18.2.4
Penstock Inspection	Program/ Activity	18.3.16
Pressurizer Examinations	Program/ Activity	18.2.5
Preventive Maintenance Activities	Program/ Activity	18.3.17
Program to Inspect High Pressure Injection Connections to the Reactor Coolant System	Program/ Activity	18.3.18
Reactor Building Spray System Inspection	Program/ Activity	18.2.6
Reactor Coolant Pump Flywheel	TLAA	ITS 5.5.8 5.4.4.2
Reactor Coolant Pump Motor Oil Collection System Inspection	Program/ Activity	18.2.7

Topic	*Program / Activity or TLAA*	*UFSAR / ITS Location*
Reactor Coolant System and Class 1 Components (includes leak-before-break) (Oconee Thermal Fatigue Management Program)	TLAA	5.2.1.4 5.2.x 18.4
Reactor Coolant System Operational Leakage Monitoring	Program/ Activity	ITS 3.4.13 ITS 3.4.15
Reactor Vessel	TLAA	5.2.3.3.6, 5.2.3.3.x, y 18.4
Reactor Vessel Integrity Program	Program/ Activity	18.3.19
Reactor Vessel Internals	TLAA	4.5.1.2 18.4
Reactor Vessel Internals Inspection	Program/ Activity	18.3.20
Service Water Piping Corrosion Program	Program/ Activity	18.3.21
Small Bore Piping Inspection	Program/ Activity	18.2.8
Spent Fuel Rack Boraflex	TLAA	9.1.2.5
Steam Generator Tube Surveillance Program	Program/ Activity	ITS 5.5.10 18.4
System Performance Testing Activities	Program/ Activity	18.3.22
Tendon - Secondary Shield Wall - Surveillance Program	Program/ Activity	18.3.23

Topic	*Program / Activity or TLAA*	*UFSAR / ITS Location*
Treated Water Systems Stainless Steel Inspection	Program/ Activity	18.2.9
230 kV Keowee Transmission Line Inspections	Program/ Activity	18.3.24

18.2 ONE-TIME INSPECTIONS FOR LICENSE RENEWAL

18.2.1 CAST IRON SELECTIVE LEACHING INSPECTION

Purpose – The purpose of the *Cast Iron Selective Leaching Inspection* will be to characterize loss of material due to selective leaching of 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. 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 Low Pressure Service Water System, the Condenser Circulating Water System, the Service Water System (Keowee), the Chilled Water System, the Condensate System, 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 – A representative sample of six pump casings will be inspected for evidence of selective leaching, one from each of the following systems on-site:

- Auxiliary Service Water System
- Chilled Water System
- Low Pressure Service Water 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 Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the *Cast Iron Selective Leaching Inspection.*

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.2 GALVANIC SUSCEPTIBILITY INSPECTION

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 or destructive examination at the junction of the carbon steel - stainless steel components will be performed to determine material loss from the more anodic carbon steel. The most susceptible locations will be identified. The exact method of examination will be determined at the time of the 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
- Chilled Water System (raw water portion of the chillers)
- Component Cooling System (raw water portion of the Component Cooler)
- Condensate System (raw water portions of the Condensate Cooler and Main Condenser within the scope of license renewal)
- Condenser Circulating Water System
- Diesel Jacket Water Cooling System (raw water portion of the jacket water heat exchanger)
- 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)
- Standby Shutdown Facility Auxiliary Service Water System
- Turbine Generator Cooling Water System (Keowee)
- Turbine Sump Pump System (Keowee)

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 Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the *Galvanic Susceptibility Inspection.*

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.3 KEOWEE AIR AND GAS SYSTEMS INSPECTION

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 – Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, 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 Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the *Keowee Air and Gas Systems Inspection.*

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.4 ONCE THROUGH STEAM GENERATOR UPPER LATERAL SUPPORT INSPECTION

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. The OTSG containing these pads will be randomly selected from the total population of six OTSG at Oconee.

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 visible cracking in the lubrite pads.

Corrective Action – If the sample lubrite pads are cracked, then the affected pads will be replaced and the remaining 25 lubrite pads will be inspected. 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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.5 PRESSURIZER EXAMINATIONS

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

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 and loss of fracture toughness due to thermal embrittlement of the spray head [Reference 18-3] 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.

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.5.2 Pressurizer Heater Bundle Penetration Welds Examination

Purpose – The purpose of the *Pressurizer Heater Bundle Penetration Welds Examination* will be to assess the condition of the Unit 1 pressurizer heater penetration welds.

Scope – The results of this examination will be applicable to the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds for the pressurizer heater bundles of Oconee Unit 1 (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not required.[Reference 18-4]

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.

Sample Size – The examination will include sixteen peripheral heater penetration welds on one heater bundle from Oconee Unit 1, whichever heater bundle is removed first. The examination will include the heater sheath-to-sleeve and heater sleeve-to-diaphragm plate penetration welds of the sixteen peripheral heaters.

Industry Code or Standards – ASME Section XI.

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.*

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. This examination will be aligned to when a Unit 1 heater bundle is replaced whenever that may occur, due to the impractical nature of such an inspection otherwise. The failure of a structural weld that attaches the heater sheath to the Alloy 600 heater sleeve or failure of the weld that attaches the heater sleeve to the Alloy 600 diaphragm plate would result in leakage within the make-up system capacity and the integrity of the heater bundle bolted closure would not be compromised. No loss of pressurizer function would occur due to leakage at either of these welds. The examination will provide insights into the condition of the other similarly constructed pressurizer heater bundles in Oconee Unit 1. [Reference 18-5]

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.6 Reactor Building Spray System Inspection

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. Results of this inspection will be applied to not only the Reactor Building Spray System, but also to the Nitrogen Purge and Blanketing System.

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, 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. Some of the parameters Duke may use to select the most bounding inspection location are piping geometry, presence of weld and heat affected zone, accessibility of location and radiation exposure. [Reference 18-6]

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

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

Acceptance Criteria or Standard – No cracking will be permitted. Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, 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 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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.7 Reactor Coolant Pump Motor Oil Collection System Inspection

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 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 examination 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 that 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. The collection tank chosen for inspection will be based on any higher frequency that water has been observed in the oil as well as accessibility and radiological concerns. [Reference 18-7]

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 – Any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, 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 various forms of corrosion will require that an engineering analysis be performed to determine proper corrective action. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the *Reactor Coolant Pump Motor Oil Collection System Inspection.*

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.8 Small Bore Piping Inspection

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 inservice inspection Class A piping welds in lines less than 4 inch nominal pipe size 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 small break loss of coolant accident 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 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, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.2.9 Treated Water Systems Stainless Steel Inspection

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 two 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)
- Chilled Water System (containing potable water)
- Demineralized Water System (Containment penetration portion containing demineralized water)
- Diesel Jacket Cooling Water System (containing demineralized 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 two groups of system components will be inspected. 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 Problem Investigation Process. The Problem Investigation Process will apply to all structures and components within the scope of the *Treated Water Systems Stainless Steel Inspection.*

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).

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3 AGING MANAGEMENT PROGRAMS AND ACTIVITIES

18.3.1 ALLOY 600 AGING MANAGEMENT PROGRAM

Purpose – The purpose of the Oconee *Alloy 600 Aging Management Program* will be to manage cracking due to primary water stress corrosion cracking (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 600 material and Alloy 82/182 weld material in the Oconee Reactor Coolant System, including the hot leg flowmeter element. The scope does not include steam generator tubes, sleeves, and plugs.

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 five 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. The five most susceptible locations are the CRDM nozzles at Oconee Unit 2, the pressurizer heater sleeves at Oconee Unit 1, the pressurizer level taps and safe ends at Oconee Unit 3, and the pressurizer vent nozzle at Oconee Unit 3.

Industry Code or Standards – ASME Section XI.

Frequency – The frequency of subsequent inspections 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 be used to 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. Either a complete 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, the initial inspection of selected locations will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis – Application [Reference 18-1], Duke Response to RAIs 4.3.1-1, -2, -3, -4, -5, and –6 [Reference 18-8], and Final SER [Reference 18-2].

18.3.2 CHEMISTRY CONTROL PROGRAM

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. To ensure the best protection is provided, reactor coolant water quality specifications are based upon the current revision of the EPRI PWR Primary Water Chemistry Guidelines and vendor recommendations as appropriate [UFSAR Section 5.2.1.7]. Secondary chemistry specifications are based upon the recommendations in the current revision of the EPRI PWR Secondary Water Chemistry Guidelines.

For component cooling water, Oconee utilizes a modified 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. For the SSF diesel jacket water cooling system, Oconee utilizes the industry-standard diesel jacket water cooling treatment method (sodium nitrite/borax/tolytriazole).

The Oconee SSF Fuel Oil surveillances are governed by Oconee Technical Specifications [ITS SR 3.10.1.8 and ITS 5.5.14]. The applicable ASTM standard is ASTM D975 Standard, "Standard Specification for Diesel Fuel Oils."

Acceptance criteria for each monitored parameter have been established and are described in the applicable section of the Oconee Chemistry Manual. In the event the acceptance criteria are not met, then specific corrective actions will be implemented in accordance with the Problem Investigation Process.

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.3 CONTAINMENT INSERVICE INSPECTION PLAN

The Oconee *Containment Inservice Inspection Plan* implements 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." The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

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 paragraph (b)(2)(vi) and the modifications listed in paragraphs (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;

(2) Comply with §50.55a, 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 the requirements contained in §50.55a, for Commission evaluation.

18.3.4 Control Rod Drive Mechanism Nozzle and Other Vessel Closure Penetrations Inspection Program

Purpose – The purpose of the Control Rod Drive Mechanism *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 primary water stress corrosion cracking in B&W-designed control rod drive mechanism (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 – Eddy current inspection will be utilized for detection. Eddy current, ultrasonic, and liquid penetrate may be used for sizing, as appropriate.

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. Future inspections will be established upon review of these inspection results.

Acceptance Criteria or Standard – Axial flaws detected during inspection will be analyzed and evaluated using the NUMARC acceptance criteria that 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 18-9].

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 time-limited aging analyses and are addressed by the Oconee *Thermal Fatigue Management Program*. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis – Duke response to NRC Generic Letter 97-01 [Reference 18-10], Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.5 CRANE INSPECTION PROGRAM

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.

Industry Code or Standard – ANSI B30.2.0 [Reference 18-11] for cranes and ANSI B30.16 [Reference 18-12] 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.

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.*

Regulatory Basis – 29 CFR Chapter XVII, §1910.179 [Reference 18-13], Application [Reference 18-1] and Final SER [Reference 18-2].

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

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. The examination of external surfaces covers the Keowee Intake, Spillway, and Powerhouse concrete surfaces exposed to water. The concrete structures are inspected from the foundation to the free water surface. [Reference 18-14]

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 Duke Energy in accordance with FERC requirements for maintaining other components of the structures. (See *FERC Five Year Inspections* Section 18.3.8).

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. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *Duke Power Five Year Underwater Inspection of Hydroelectric Dams and Appurtenances.*

Regulatory Basis – 18 CFR Part 12, Safety of *Water Power Project and Project Works,* Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.7 Elevated Water Storage Tank Civil Inspection

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

Scope – The scope of the program includes the interior 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 surfaces in accordance with station procedures. The inspection covers 100 % of the interior tank surfaces. [Reference 18-14]

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.*

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.8 Federal Energy Regulatory Commission (FERC) Five Year Inspections

Inspections of the 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 are performed in accordance with the requirements contained in 18 CFR Part 12, Safety of *Water Power Projects and Project Works* [Reference 18-15].

18.3.9 Flow Accelerated Corrosion Program

Purpose – The purpose of the *Flow Accelerated 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 flow accelerated 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 Main Steam System 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 flow accelerated 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.

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 actions are implemented in accordance with approved station processes, including work orders, modifications and the Problem Investigation Process.

Regulatory Basis – Duke response to Bulletin 87-01[References 18-16 and 18-17] and Duke response to Generic Letter 89-08 [References 18-18 and 18-19], Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.10 FLUID LEAK MANAGEMENT PROGRAM

Purpose – The purpose of the *Fluid Leak Management Program* is to ensure identification of leaks followed by timely investigation and repair. When boric acid leakage is involved, this program describes activities to identify the source of leakage and to evaluate subsequent corrosion degradation of associated piping, structures and components. This program includes focus on small leaks that 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 aluminum, brass, bronze, copper, galvanized steel, carbon steel and low alloy steel that are located in proximity to borated systems. Electrical equipment located in proximity to borated systems is also included. 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 – Two of the conditions evaluated by the *Fluid Leak Management Program* are loss of material from components due to boric acid corrosion of the carbon steel and low alloy steel and boric acid intrusion into electrical equipment.

Method – Visual inspections are performed on external surfaces in accordance with plant procedures. Plant personnel look for leakage from both insulated and uninsulated components, as well as general corrosion of a component that may result from leakage. Plant personnel look for borated water leakage indicators such as discoloration or accumulated residue on surfaces such as insulation materials or floors. Possible intrusion of boric acid into electrical equipment is evaluated.

Industry Code or Standard – ASME Section XI and Generic Letter 88-05 [Reference 18-20].

Frequency – Reactor Building inspections are performed each refueling outage. Inspections of the Auxiliary Building are performed at a minimum as frequently as the Reactor Building is inspected. [Reference 18-21]

Acceptance Criteria or Standard – The *Fluid Leak Management Program* defines actions to achieve the following acceptance criteria:

(1) Insulated, non-insulated or inaccessible components within borated water systems will have no external leakage, and
(2) Components within scope with degradation resulting from external leakage from borated water systems will be evaluated by engineering.

Corrective Action – When the programmatic activities described in the *Fluid Leak Management 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 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.

Specific corrective actions are implemented in accordance with the *Fluid Leak Management Program* or the Problem Investigation Process. These programs apply to all structures and components within the scope of the *Fluid Leak Management Program.*

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 18-22], Application [Reference 18-1], Final SER [Reference 18-2], and Duke letter [Reference 18-23].

18.3.11 HEAT EXCHANGER PERFORMANCE TESTING ACTIVITIES

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 coolers in the Low Pressure Injection System,
- the Reactor Building cooling units in the Reactor Building Cooling System, and
- the component coolers in the Component Cooling System
- the Standby Shutdown Facility HVAC coolers in the Standby Shutdown Facility Auxiliary Service Water System.

Periodic testing is completed each refueling outage for the decay heat removal coolers the Reactor Building cooling units. 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. 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. If an adverse trend in heat removal is found, then corrective actions will be taken.

The Standby Shutdown Facility HVAC coolers are normally in service because they are required for SSF system operability per ITS 3.10.1.D. The component coolers are normally in service because they are required to support normal plant operation. Accident load demands for these coolers are not greater than normal operation. Thus, heat removal capacity calculations are not performed for these coolers. Rather, flowrates through these coolers are monitored on a periodic basis. The Standby Shutdown Facility HVAC cooler flowrate is monitored twice per day. The component cooler flowrate is recorded on a refueling basis during performance testing. If an adverse trend in flowrate is found, then corrective actions will be taken.

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 Problem Investigation Process. This program applies to all structures and components within the scope of the *Heat Exchanger Performance Testing Activities.*

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.

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].
Also, the activities credited here for license renewal for the SSF HVAC coolers, 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 18-24, 18-25, 18-26 , 18-27, and 18-28].

18.3.12 INSERVICE INSPECTION PLAN

The Oconee *Inservice Inspection Plan,* implements the requirements of 10 CFR §50.55a for Class 1, 2, and 3 components and Class 1, 2, 3, and MC component supports. The examinations are performed to the extent practicable within the limitations of design, geometry and materials of construction of the component. 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;
(4) Comply with §50.55a 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, for Commission evaluation; and
(5) Include examination of pressurizer heater bundle welds in accordance with Examination Category B-E (or equivalent).

The Inservice Inspection Plan is credited for license renewal with managing certain aging effects associated with Reactor Coolant System pressure retaining components, their integral attachments, and other structural components within the jurisdiction of ASME Section XI. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

In addition, for Cast Austenitic Stainless Steel (CASS) Class 1 components 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 [Reference 18-1, Volume III, Exhibit A, Chapter 4, and Reference 18-2].

18.3.13 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

The *Inspection Program for Civil Engineering Structures and Components* is intended to meet the requirements of 10 CFR §50.65, *Requirements for monitoring the effectiveness of maintenance at nuclear power plants* (the Maintenance Rule). This program:

(1) monitors and assesses mechanical components, civil structures and components and their condition in order to provide reasonable assurance that they are capable of performing their intended functions in accordance with the current licensing basis;
(2) monitors degradation of caulking, sealants and waterstops in the Auxiliary Building and Standby Shutdown Facility which may include but is not limited to water in-leakage, leaching, peeling paint, or discoloration of the concrete; and
(3) includes nuclear safety-related structures which enclose, support, or protect nuclear safety-related systems and components and non-safety related structures whose failure may prevent a nuclear safety-related system or component from fulfilling its intended function.

NEI 96-03, *Industry Guideline for Monitoring the Condition of Structures at Nuclear Power Plants,* has been used as guidance in the preparation of the *Inspection Program for Civil Engineering Structures and Components.*

Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *Inspection Program for Civil Engineering Structures and Components.*

18.3.14 INSULATED CABLES AND CONNECTIONS AGING MANAGEMENT PROGRAM

Purpose – The purpose of the *Insulated Cables and Connections Aging Management Program* is to provide reasonable assurance that the license renewal intended functions of insulated cables and connections will be maintained consistent with the current licensing basis through the period of extended operation.

Scope – The *Insulated Cables and Connections Aging Management Program* includes accessible and inaccessible insulated cables within the scope of license renewal that are installed in adverse, localized environments in the Reactor Buildings, Auxiliary Buildings, Turbine Buildings, Standby Shutdown Facility, Keowee, in conduit and direct-buried, which could be subject to applicable aging effects from heat, radiation or moisture. This program does not include insulated cables and connections that are in the Environmental Qualification program. An adverse, localized environment is defined as a condition in a limited plant area that is significantly more severe than the specified service condition for the equipment. An applicable aging effect is an aging effect that, if left unmanaged, could result in the loss of a component's license renewal intended function in the period of extended operation.

Aging Effects – Change in material properties of the conductor insulation is the applicable aging effect. The changes in material properties managed by this program are those caused by severe heat, radiation or moisture — conditions that establish an adverse, localized environment, which include energized medium-voltage cables exposed to significant moisture.

Method – The methods used are different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables, which cannot be visually inspected.

Accessible insulated cables and connections installed in adverse, localized environments will be visually inspected for jacket surface anomalies such as embrittlement, discoloration, cracking or surface contamination. Surface anomalies are indications that can be visually monitored to preclude the conductor insulation applicable aging effect. In addition, water collection in manholes containing in-scope, medium-voltage cables will be monitored to prevent the cables from being exposed to significant moisture.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested. The specific type of test performed will be determined prior to each test. Significant moisture exposure is defined as periodic exposures to moisture that last more than a few days (e.g., cable in standing water). Periodic exposures to moisture that last less than a few days (i.e., normal rain and drain) are not significant. Significant voltage exposure is defined as being subjected to system voltage for more than twenty-five percent of the time. These definitions apply to cables for which no specific design characteristics are known. The moisture and voltage exposures described as significant in these definitions are not significant for medium-voltage cables that are designed for these conditions.

Sample Size – Samples may be used for this program. If used, an appropriate sample size will be determined prior to the inspection or test.

Industry Codes and Standards – EPRI TR-109619, *Guideline for the Management of Adverse Localized Equipment Environments* will be used as guidance in implementing this program.

Frequency – Accessible insulated cables and connections installed in adverse, localized environments will be inspected at least once every 10 years. Water collection in manholes containing in-scope, medium-voltage cables will be monitored at a frequency adequate to prevent the cables from being exposed to significant moisture.

Inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage will be tested at least once every 10 years.

Acceptance Criteria or Standard – The acceptance criteria is different for accessible insulated cables and connections and for inaccessible or direct-buried medium-voltage cables.

For accessible insulated cables and connections installed in adverse, localized environments, the acceptance criteria is no unacceptable, visual indications of jacket surface anomalies, which suggest that conductor insulation applicable aging effect may exist, as determined by engineering evaluation. An unacceptable indication is defined as a noted condition or situation that, if left unmanaged, could lead to a loss of the license renewal intended function. In-scope, medium-voltage cables in manholes found to be exposed to significant moisture will be tested as described for inaccessible cables under Method, Frequency and Acceptance Criteria of this program.

For inaccessible or direct-buried, medium-voltage cables exposed to significant moisture and significant voltage, the acceptance criteria for the test will be defined by the specific type of test to be performed and the specific cable to be tested.

Corrective Action – Further investigation by engineering will be performed on accessible and inaccessible insulated cables and connections when the acceptance criteria is not met in order to ensure that the license renewal intended functions will be maintained consistent with the current licensing basis. Corrective actions may include, but are not limited to, testing, shielding or otherwise changing the environment, relocating or replacement. Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *Insulated Cables and Connections Aging Management Program*. When an unacceptable condition or situation is identified, a determination will be made as to whether this same condition or situation could be applicable to other accessible or inaccessible cables and connections.

Timing of New Program or Activity – Following issuance of a renewed operating licenses for Oconee Nuclear Station, the initial inspections and tests will be completed by February 6, 2013 (the end of the initial license term for Oconee Unit 1).

Regulatory Basis – Duke response to SER Open Item 3.9.3 [Reference 18-29] and Final SER [Reference 18-2].

18.3.15 KEOWEE OIL SAMPLING PROGRAM

Purpose – The purpose of the *Keowee Oil Sampling Program* is 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* manages 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 contains elements that 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 of the stainless steel components in the raw water environment of the shell side of the cooler. 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* requires that the Governor Oil System Sump and Turbine Guide Bearing Oil System reservoirs be sampled for the presence of water contamination. Results of the analysis are monitored and trended.

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

Frequency – Oil samples are taken and analyzed every six months.

Acceptance Criteria or Standard – No water contamination in excess of 0.1% water by volume is 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 are made in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.16 PENSTOCK INSPECTION

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.

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

Frequency – Inspections are performed when 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 that do not meet the acceptance criteria are evaluated by the accountable engineer for continued service or corrected by repair or replacement.
Specific corrective actions will be implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *Penstock Inspection.*

Regulatory Basis – 18 CFR Part 12, Safety of *Water Power Projects and Project Work.*

18.3.17 PREVENTIVE MAINTENANCE ACTIVITIES

18.3.17.1 Borated Water Storage Tank Internal Coatings Inspection

A visual inspection of the internal coating of the tank will be performed every third refueling outage with the borated water removed from the tank. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Borated Water Storage Tank Internal Coating Inspection.

18.3.17.2 Chilled Water Refrigeration Unit Preventive Maintenance Activity

For the portions of the exposed to raw water in the condensing heat exchangers of the refrigeration unit, system parameters of the entire refrigeration unit are monitored during operation to provide evidence of fouling and loss of material. Parameters monitored are monitored quarterly and include inlet and outlet temperatures along with refrigerant pressures. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Chilled Water System Refrigeration Unit Preventive Maintenance Activity.

18.3.17.3 Component Cooler Tubing Examination

Eddy current testing of component cooler tubing is performed every other refueling outage. Approximately 100% of the tubing is examined. The acceptance criterion for the inspection is that all tube wall loss indications shall be less than 60% through wall. Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Component Cooler Tubing Examination.

18.3.17.4 Condensate Cooler Tubing Examination

Eddy current testing of condensate cooler tubing is performed every third refueling outage. The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry (approximately 25% of the tubes), are tested. The acceptance criterion for the inspection is that all wall loss indications must be less than 60% through wall. Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condensate Cooler Tubing Examination.

18.3.17.5 Condenser Circulating Water System Internal Coatings Inspection

A visual inspection of the interior surfaces of the underground portions of the Condenser Circulating Water System intake and discharge piping is performed every five years. The acceptance criterion is no visual indications of coating defects that have exposed the base metal. Engineering evaluation is performed to determine whether coating and base metal continue to be acceptable. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Condenser Circulating Water System Internal Coatings Inspection.

18.3.17.6 Control Room Ventilation System Examination

A visual inspection of the exterior surfaces of the Control Room Pressurization Filtration System components, including seals, sealants, rubber boots, and flexible collars is performed quarterly. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Control Room Ventilation System Examination.

18.3.17.7 Decay Heat Cooler Tubing Examination

Eddy current testing of the Decay Heat Cooler tubing is performed every fourth refueling outage. All of the inservice stainless steel heat exchanger tubes are examined. The acceptance criterion for the inspection is that all wall loss indications are less than 60% through wall. Tubes with wall loss indications greater than 60% through wall are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Decay Heat Cooler Tubing Examination.

18.3.17.8 Fire Hydrant Flow Test

Fire Hydrant Flow Test is an activity within the Fire Protection Program that was credited in license renewal. (Selected Licensee Commitments apply to other credited portions of the Fire Protection Program.) A flow test of fire hydrants is performed periodically. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all license-renewal related components within the scope of the Fire Hydrant Flow Test.

18.3.17.9 Jacket Water Heat Exchanger Preventive Maintenance Activity

System parameters of the entire Diesel Jacket Water Cooling System (i.e., system operating temperatures, pressures, and expansion tank levels) are monitored during diesel engine operation as required by Technical Specification Surveillance Requirement 3.10.1.9. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Jacket Water Heat Exchanger Preventive Maintenance Activity.

18.3.17.10 Keowee Turbine Generator Cooling Water System Strainer Inspection

A visual inspection of the strainer is performed weekly on the turbine packing box cooler water strainer and bimonthly on the main inlet strainer. Any noticeable sign of loss of material is documented. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Keowee Turbine Generator Cooling Water System Strainer Inspection.

18.3.17.11 Main Condenser Tubing Examination

Eddy current testing is performed on ten percent of the tubes in one-half of the condenser each refueling outage. Tubes in each half of the condenser are examined every other refueling outage. The acceptance criterion for the examination is that all tubing wall loss indications will be less than 60% through wall. Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Main Condenser Tubing Examination.

18.3.17.12 Reactor Building Auxiliary Cooler Inspection

A pressure test and visual inspection of all of the tubing of one tube bundle (consisting of four coils) is performed each refueling outage. The acceptance criteria are no visible leakage resulting from pressure testing. In addition, any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Reactor Building Auxiliary Cooler Inspection.

18.3.17.13 Reactor Building Cooling Unit Tubing Inspection

Each refueling outage or as required by periodic performance testing, tubes are rodded out and visually inspected. In addition, the shell is cleaned and visually inspected. The acceptance criterion is any indication of loss of material will be documented and the need for further analysis determined. No unacceptable loss of material will be permitted, as determined by engineering analysis. Visual inspection of the ductwork and internal supports is performed on the frequency of the performance testing. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Reactor Building Cooling Unit Inspection.

18.3.17.14 Standby Shutdown Facility Diesel Fuel Oil Tank Inspection

A visual inspection of the interior surface of the tank is performed every ten years with the fuel oil removed from the tank. The acceptance criterion is no visual indications of loss of material as determined by Engineering. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the Standby Shutdown Facility (SSF) Diesel Fuel Oil Tank Inspection.

18.3.17.15 Standby Shutdown Facility HVAC Coolers Preventive Maintenance Activity

Inlet and outlet temperatures of all three coolers as well as refrigerant conditions are monitored every six months. A visual inspection of the aluminum fins on the air cooling coils is performed every six months. For the water-cooled SSF HVAC condensers, cooling water and air operating temperatures will be within appropriate operating range and refrigerant will be within appropriate specifications. For the air cooling coil, the acceptance criterion is no indications of loss of material of the aluminum fins. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the SSF HVAC Coolers Preventive Maintenance Activity.

Regulatory Bases for the preceding Preventive Maintenance Activities:

- Application [Reference 18-1].
- W. R. McCollum Jr., (Duke) letter dated December 14, 1998, to Document Control Desk (NRC), Response to NRC letter dated October 29, 1998, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- M. S. Tuckman (Duke) letter dated September 30, 1999, to Document Control Desk (NRC), Amendment 1 – CLB Changes for 1999, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- M. S. Tuckman (Duke) letter dated October 15, 1999, to Document Control Desk (NRC), Safety Evaluation Report, Comments and Responses to Open Items and Confirmatory Items, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.
- Final SER [Reference 18-2].

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

Purpose – The purpose of the *Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System* is to manage the tightness of the interface between the HPI nozzle thermal sleeves and safe ends and to manage the cracking of the 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 18-30] and IE Bulletin 88-08 [Reference 18-31], 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.

The commitments of Oconee letter from Mr. W. R. McCollum, Jr. to U.S. Nuclear Regulatory Commission of January 7, 1998 on Oconee Nuclear Site, Docket Nos. 50-269, -270, -287, Inservice Inspection Program, Third Yen-Year ISI Interval, GL 85-20 Supplemental Information [in answer to the NRC letter from David E. LaBarge to Mr. W. R. McCollum of October 23, 1997, High Pressure Injection System Augmented Inservice Inspection Program - Oconee Nuclear Station Units 1, 2, and 3 (TAC No. M98454)] will continue to apply.

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 leak.

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.

Ultrasonic inspections shall meet the requirements of either Appendix VIII of Section XI of 1992 w/1993 addenda ASME, or mockups containing thermal fatigue cracks will be used.

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 – For the base metal or weld metal, the acceptance criteria are no flaws in welds and base metal in accordance with ASME Section XI acceptance criteria and 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).

For the protective thermal sleeve and the nozzle safe end, the acceptance criterion is no increase in size of the gaps between the thermal sleeve and safe end.

Corrective Action – Flaws that can be justified for continued service become time-limited aging analyses and are addressed by the Oconee *Thermal Fatigue Management Program.* Flaws in weld or base metal that 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 be implemented in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2]. 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).*

18.3.19 REACTOR VESSEL INTEGRITY PROGRAM

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 18-32] 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. These subprograms are described in the following sections.

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.19.1 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 18-33] and in BAW 2251 [Reference 18-34]. 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 [Reference18-33].

Industry Code or Standard – ASTM E 185 [Reference 18-35]; Regulatory Guide 1.99, Revision 2 [Reference 18-36]; ASTM standards as identified in Section 5.0 of BAW-1543A, Revision 2 [Reference 18-33], and BAW-1543, Revision 4, Supplement 2 [Reference 18-37];

Frequency – The capsule withdrawal schedules are presented in BAW-1543, Revision 4, Supplement 2 [Reference 18-37]. 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. The fracture toughness specimens removed from the surveillance capsules will also be evaluated to determine the adjusted reference temperature for the pressure-temperature limits (Section IV.A of Appendix G, 10 CFR Part 50) and RT_{PTS} value have been appropriately determined (10 CFR §50.61(c)(2)).

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.

Modifications to design and operation that result in changes to the neutron energy spectrum relative to that discussed in Chapter 4 of BAW-1543, Revision 4, must be compared to the energy spectrum in which the capsules were irradiated. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised neutron energy spectrum. The subsequent impact on the applicable embrittlement evaluations must be assessed.

Modifications to design and operation that result in changes to gamma heating relative to that discussed in BAW-1543, Revision 4, must be evaluated since gamma heating affects the 1/4T location. If the neutron spectrum changes and gamma heating changes, the surveillance data obtained during the current term of operation must be adjusted to account for the revised gamma heating. The subsequent impact on the applicable embrittlement evaluations must be assessed.

Modifications to design and operation that result in reactor vessel inlet temperature changes relative to those discussed in Chapters 3 and 4 of BAW-1543, Revision 4, must be assessed relative to the inlet temperature at which the applicable capsules were irradiated. If appropriate, the surveillance data obtained during the current term of operation must be adjusted to account for the revised vessel inlet temperatures. The subsequent impact on the applicable embrittlement evaluations must be assessed.

If modifications to design and operation result in changes to neutron energy spectrum, gamma heating, or the reactor inlet temperature relative to that discussed in BAW-1543, Revision 4, then NRC will be notified and a program to determine impact will be proposed. [References 18-38 and 18-39]

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

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.

18.3.19.2 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.

Industry Code or Standard – Regulatory Guide 1.99, Revision 2 [Reference 18-36]; ASTM E 185 [Reference 18-35]; Draft Regulatory Guide - 1053 [Reference 18-40]; BAW-2241P [Reference 18-41].

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 $\pm$20%. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

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.

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.

18.3.19.3 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.

Industry Code or Standard – Regulatory Guide 1.99, Revision 2 [Reference 18-36]; ASTM E 185 [Reference 18-35]; Draft RG-1053 [Reference 18-40], BAW-2241P [Reference 18-41].

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.*

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.*

18.3.19.4 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 limit curves will be generated in accordance with the requirements of Appendix G of 10 CFR Part 50. Pressure temperature curves are generated assuming a postulated 1/4T surface flaw in accordance with ASME Section XI, Appendix G [Reference 18-42]. Bounding input heatup and cooldown transients are used to develop the pressure temperature curves.

Industry Code or Standard – ASME Section XI, Appendix G, 1989 Edition [Reference 18-42]; ASME Code Case N-514 [Reference 18-43]; Regulatory Guide 1.99, Revision 2 [Reference 18-36], 10 CFR 50, Appendix G.

Frequency – *Pressure Temperature Limit Curves* are valid for a period of time expressed in Effective Full Power Years (EFPY). The curves are 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 exceeded are specified in Oconee Improved Technical Specifications 3.4.3. Specific corrective actions will be implemented 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.*

18.3.19.5 Effective Full Power Years

Effective Full Power Years provide a measurement of the irradiation of the reactor vessel and is required input for determining pressure - temperature limit curves and pressurized thermal shock guidelines. 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 irradiation of the reactor vessel. .

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.

Industry Code or Standard – No code or standard exists to guide or govern this activity.

Frequency – Each unit is continuously monitored by computer 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 $\pm$ 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.*

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

18.3.20 REACTOR VESSEL INTERNALS INSPECTION

Purpose – The purpose of the *Reactor Vessel Internals Inspection* is to inspect and examine the condition of reactor vessel internals items in order to assure that the applicable aging effects will not result in loss of the intended functions of the reactor vessel internals during the period of extended operation.

Scope – The scope of this inspection consists of the reactor vessel internals stainless steel items for Oconee Units 1, 2 and 3. For inspection purposes, these items can be separated into four groups – (1) items comprised of plates, forgings, and welds, (2) baffle bolts, (3) core barrel bolts and thermal shield bolts, and (4) items fabricated from cast austenitic stainless steel (CASS) and martensitic steel. More specifically, the items fabricated from CASS and martensitic steel include control rod guide tube spacers, vent valve bodies, Unit 3 outlet nozzles, and incore guide tube assembly spiders. The vent valve retaining rings, fabricated from martensitic stainless steel, are also included in this inspection.

Aging Effects – The applicable aging effects for items comprised of plates, forgings, and welds are cracking due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation embrittlement, and dimensional changes due to void swelling.

The applicable aging effects for baffle bolts are cracking due to irradiation assisted stress corrosion, reduction of fracture toughness due to irradiation embrittlement, and dimensional changes due to void swelling.

The applicable aging effects for items comprised of core barrel bolts, and thermal shield bolts are cracking due to irradiation assisted stress corrosion, stress corrosion, reduction of fracture toughness due irradiation embrittlement, and loss of bolted closure integrity due to stress relaxation.

The applicable aging effects for item fabricated from CASS and martensitic steel are reduction of fracture toughness by thermal embrittlement and irradiation embrittlement.

Method – Current plans are to perform a visual inspection of the items comprised of plates, forgings, and welds. Activities are in progress to develop and qualify the inspection method.

Current plans are to perform a volumetric inspection of the baffle bolts. Activities are in progress to develop and qualify the inspection method.

Current plans are to perform a visual inspection of core barrel bolts and thermal shield bolts. Activities are in progress to determine if volumetric examinations will be required.

For items fabricated from CASS and martensitic steel, an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items will be performed. The specific inspection method will depend on the results of these analyses. The Oconee Unit 3 outlet nozzles will be inspected if the results of the analysis indicate such inspection is necessary.

Should data or evaluations indicate that the above inspections can be modified or eliminated, Duke will provide plant-specific justification to demonstrate the basis for the modification or elimination.

Sample Size – The sample size for the inspection of each Oconee unit will be determined as part of the development of the inspection method.

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

Frequency – The *Reactor Vessel Internals Inspection* will be performed once on each set of reactor vessel internals during the twenty-year period of extended operation. Preparation for these inspections will include unit selection and proper sequencing of the inspections as well as the opportunity to develop a lead unit for these inspections.

Acceptance Criteria or Standard – For the items comprised of plates, forgings, and welds that will be visually inspected, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed prior to the inspection.

For baffle bolts, any detectable crack indication is unacceptable for a particular baffle bolt. The number of baffle bolts needed to be intact and their locations will be determined by analysis. Acceptance criteria for dimensional changes due to void swelling will be developed prior to the inspection.

For core barrel bolts, and thermal shield bolts any detectable crack is unacceptable. Acceptance criteria for all aging effects will be developed prior to the inspection.

For items fabricated from CASS and martensitic steel, critical crack size will be determined by analysis. Acceptance criteria for all aging effects will be developed prior to the inspection.

Corrective Action – If the results of the inspection are not acceptable, then actions will be taken to repair or replace the affected items or to determine by analysis the acceptability of the items. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity – The inspections among the three sets of reactor vessel internals will be spaced out over the twenty-year period of extended operation. The first inspection will occur early in the period. The second will occur near the middle of the period, and the third will occur in the latter third of the twenty-year period. (The third inspection will be scheduled prior to the last year of the twenty-year period of extended operation for the unit inspected.)

Regulatory Basis – Renewal Applicant Action Item 4.1 (Items 5, 6, 7, 8, and 9) in the Safety Evaluation Report for BAW-2248A. Duke letter dated December 17, 1999 [Reference 18-44], and Final SER [Reference 18-2].

18.3.21 SERVICE WATER PIPING CORROSION PROGRAM

Purpose – The *Service Water Piping Corrosion Program* will manage loss of material due to general and localized corrosion for components in the following systems:

- Auxiliary Service Water System,
- Chilled Water System (raw water portion of the coolers)
- Component Cooling System (raw water side of the component coolers)
- Condenser Circulating Water System,
- Diesel Jacket Water Cooling System (raw water side of the heat exchangers)
- Essential Siphon Vacuum System
- High Pressure Service Water System,
- Keowee Service Water System,
- Keowee Turbine Generator Cooling Water System, and
- Keowee Turbine Sump Pump System.
- Low Pressure Injection System (for the raw water side of the Decay Heat Cooler),
- Low Pressure Service Water System,
- Siphon Seal Water System
- SSF Auxiliary Service Water 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 includes the inspection of 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. In addition, brass piping components located at Keowee are inspected.

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 brass, carbon steel, and cast iron components and loss of material due to localized corrosion for brass, 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.

Industry Codes and Standards – No code or standard exists to guide or govern this inspection. 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 frequency of re-inspection depends on previous inspection results, calculated rate of material loss, piping analysis review, pertinent industry events and plant operating experiences.

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 are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *Service Water Piping Corrosion 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 18-24, 18-25 18-26, 18-27 and 18-28]; Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.22 SYSTEM PERFORMANCE TESTING ACTIVITIES

The following raw water systems have been identified as containing smaller diameter piping that could be affected by fouling and will be managed by *System Performance Testing Activities*:

- Auxiliary Service Water System,
- Keowee Turbine Generator Cooling Water System,
- Keowee Turbine Sump Pump System,
- Low Pressure Service Water System,
- Siphon Seal Water System, and
- SSF Auxiliary Service Water 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.

Periodic operation, testing and inspections are completed for the above systems at a range of frequencies. The Turbine Generator Cooling Water System is operated at design conditions every time the Keowee units operate. The Keowee units operate at about a ten percent capacity factor. Periodic testing frequencies range from quarterly to every third refueling outage, depending on the system. 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 Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *System Performance Testing Activities.*

The activities credited here for license renewal are consistent with the Oconee commitments made in response to Generic Letter 89-13 [References 18-24, 18-25 18-26, 18-27 and 18-28].

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.

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.23 TENDON - SECONDARY SHIELD WALL - SURVEILLANCE PROGRAM

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 – Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons.

Industry Code or Standard – No code or standard exists to guide or govern this program.

Frequency – Lift-off tests and visual inspections are performed on three randomly selected horizontal tendons every other refueling outage.

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. The minimum required forces for the tendon groups range from 390 kips to 560 kips depending on the location of the group.

Corrective Action – Areas that 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.*

Regulatory Basis – Application [Reference 18-1] and Final SER [Reference 18-2].

18.3.24 230 kV Keowee Transmission Line Inspection

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* includes 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.

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 that do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement. Specific corrective actions are implemented in accordance with the Problem Investigation Process. The Problem Investigation Process applies to all structures and components within the scope of the *230 kV Keowee Transmission Line Inspection.*

Regulatory Basis – National Electric Safety Code, Part 2, *Safety Rules for Overhead Lines*, Rule 214 *Inspection and Tests of Lines and Equipment*, Application [Reference 18-1] and Final SER [Reference 18-2].

18.4 ADDITIONAL COMMITMENTS

The following are additional commitments that are not identified in the preceding sections of Chapter 18:

1. A plant-specific analysis will be performed to demonstrate that, under loss-of-coolant-accident (LOCA) and seismic loading, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and that irradiation accumulated at the expiration of the renewal license will not adversely affect deformation limits. Data will be developed to demonstrate that the internals will meet the deformation limits at the expiration of the renewal license. (Reference: Duke letter to the NRC dated December 17, 1999, Attachment 1, page 8)

2. The Steam Generator Tube Surveillance Program complies with the guidance provided in NEI 97-06, "Steam Generator Program Guidelines" for inspection scope, personnel qualification, and technique qualification. Condition monitoring and operational assessments are performed using the NEI 97-06 guidelines. (Reference: Duke letter to NRC dated February 17, 1999, Attachment 1, page 63)

3. Tables 5-1 through 5-6 of the UFSAR Supplement contain reactor vessel materials data. These tables will be revised to include the current data from BAW-2325 (Revision 1 or the most current revision available) by December 31, 2000. (Reference: Duke letter to NRC dated March 27, 2000, Submittal of UFSAR Supplement, March 2000)

4. The Oconee Thermal Fatigue Management Program will be modified to incorporate a plant-specific resolution of Generic Safety Issue (GSI)-190, "Fatigue Evaluation of Metal Components for 60-year Plant Life." Plant-specific actions will be taken either in the manner that was described in Duke letter to the NRC dated October 15, 1999, "Safety Evaluation Report – Oconee Nuclear Station License Renewal Application, Comments and Responses to Open Items and Confirmatory Items, Response to Open Item 4.2.3-2," or by using another approach that is acceptable to the NRC staff. (Reference: Duke letter to NRC dated October 15, 1999, Attachment 2, page 111)

18.5 References

18-1. *Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3,* submitted by M. S. Tuckman (Duke) letter dated July 6, 1988 to Document Control Desk (NRC), Docket Nos. 50-269, -270, and -287.

18-2. NUREG-1723, *Safety Evaluation Report Related to the License Renewal of Oconee Nuclear Station*, Units 1, 2, and 3, Docket Nos. 50-269, 50-270, and 50-287.

18-3. M. S. Tuckman Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-4. M. S. Tuckman Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-5. M. S. Tuckman Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.4.3.3-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-6. M. S. Tuckman (Duke) letter dated May 10, 1999 to Document Control Desk (NRC), Attachment 1, Response to Items 4.3.9-6, -7, and –8, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-7. M. S. Tuckman Duke) letter dated October 15, 1999 to Document Control Desk (NRC), Response to Safety Evaluation Report (SER) Open Items, Attachment 2, SER Open Item 3.6.2.3.2-1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-8. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Attachment 1, Pages 43-48, Response to Requests for Additional Information, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-9. W. T. Russell (NRC) letter dated November 19, 1993 to W. H. Rasin (NUMARC, now NEI).

18-10. 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.

18-11. 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.

18-12. ANSI B30.16, "Overhead Hoists (Underhung)", The American Society of Mechanical Engineers, New York.

18-13. 29 CFR Chapter XVII, §1910.179, *Occupational Safety and Health Administration, Overhead and Gantry Cranes.*

18-14. W. R. McCollum, Jr. (Duke) letter dated February 8, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information (RAI), Attachment 1, Response to RAI 4.12-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18-15. 18 CFR Part 12 - *Safety of Water Power Projects and Project Works*, 59 FR 54815, Nov. 2, 1994.

18-16. IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants.*

18-17. 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.

18-18. Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning.*

18-19. 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.

18-20. Generic Letter 88-05, *Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants*, dated March 17, 1988.

18-21. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999 to Document Control Desk (NRC), Response to Requests for Additional Information Attachment 7, Commitment #1, Oconee Nuclear Station, Docket Nos. 50-269, -270, and -287.

18-22. 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.

18-23. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18-24. 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.

18-25. 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.

18-26. 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.

18-27. 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.

18-28. 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.

18-29. M. S. Tuckman (Duke) letter dated January 12, 2000, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Revised Response to SER Open Item 3.9.3-1, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18-30. Generic Letter 85-20, *Resolution of Generic Issue 69: High Pressure Injection/Make-up Nozzle Cracking in Babcock and Wilcox Plants.*

18-31. IE Bulletin 88-08, *Thermal Stresses in Piping Connected to the Reactor Coolant System.*

18-32. 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.

18-33. BAW-1543A, Revision 2, *Integrated Reactor Vessel Surveillance Program,* B&W Owners Group Materials Committee, May 1985.

18-34. BAW-2251, *Demonstration of the Management of Aging Effects for the Reactor Vessel,* The B&W Owners Group Generic License Renewal Program, June 1996.

18-35. ASTM E 185, *Standard Practice for Conducting Surveillance Test for Light-Water Cooled Nuclear Power Reactor Vessels.*

18-36. Regulatory Guide 1.99, Revision 2, NRC, *Radiation Embrittlement of Reactor Vessel Material, May 1998.*

18-37. 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.

18-38. W. R. McCollum, Jr. (Duke) letter dated February 17, 1999, Response to Request For Additional Information, Attachment 1, Response to RAI 3.4.5-2 pages 24 and 25, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18-39. M. S. Tuckman (Duke) letter dated May 10, 1999, to Document Control Desk (NRC), Response to Requests for Additional Information, Attachment 1, Response to Potential Open Item 3.4.5-9, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.

18-40. Draft Regulatory Guide - 1053, *Calculational and Dosimetry Method for Determining Pressure Vessel Neutron Fluence,* June 1996.

18-41. BAW-2241P, *Fluence and Uncertainty Methodologies,* April 1997 (under NRC review as of June 1998).

18-42. ASME Section XI, Appendix G for Nuclear Power Plants, Division 1, *Protection Against Non-Ductile Failure.*

18-43. ASME Code Case N-514, *Low Temperature Overpressure Protection*, Section XI, Division 1.

18-44. M. S. Tuckman (Duke) letter dated December 17, 1999, to Document Control Desk (NRC), Response to NRC letter dated November 18, 1999, Response to SER Open Items 3.4.3.3-3, 3.4.3.3-4, and 3.4.3.3-5, Oconee Nuclear Station, Units 1, 2, and 3, Docket Nos. 50-269, -270, and -287.