Attachment 1

Comments
on the
Safety Evaluation Report Related to the License Renewal Application of Oconee Nuclear Station, Units 1, 2, and 3 (SER) June 1999

October 15, 1999

1. Clarify Basis for Program Evaluation Conclusions

Duke used one set of attributes to evaluate aging management programs and activities. This set of attributes was derived from several sources as described in Section 4.2 of Exhibit A of the Application. The staff in its review uses a different set of attributes to evaluate the aging management programs and activities. The link between the two sets of attributes is not so apparent. In its conclusion for each program or activity reviewed, the staff typically states that the applicant has demonstrated (emphasis added) that the program or activity is effective at managing the aging effects of concern. It would seem then that the fundamental basis for the staff conclusion on the specific program is the information provided by Duke in the Application and in responses to staff requests for additional information.

Since the program attributes in the Application form the basis of the current UFSAR Supplement (Exhibit B of the Application), a clearer link between the staff review and Duke attributes would allow the UFSAR Supplement to be maintained in a manner that avoids differing interpretations in the future.

2. Revise Pressurized Thermal Shock Discussion for Oconee Unit 2

The Unit 2 reactor vessel pressurized thermal shock discussion in SER Section 4.2.4.3.3 does not contain the most current results. Duke letter dated February 17, 1999, Attachment 1, response to RAI 5.4.2-1 provides the most current results based on materials data from B&W Owners Group Topical Report BAW-2325. The RT PTS value for Unit 2 is 296.8 °F. In addition, because the value is now below the PTS screening criterion, Duke withdrew the commitment that is described in the SER on page 4-19. Attachment 7 of the above letter, Item #8, clearly states that the commitment has been withdrawn.

3. Discuss Leak-Before-Break Evaluation in SER Section 4.2

In response to RAI 5.4.1-1, Duke provided a substantial discussion of leak-before-break (LBB) for Oconee. Subsequent to the submittal of the Application in July 1998, Duke identified LBB as a TLAA and provided the results of the evaluation in the above response. Section 4.2 does not include any mention of LBB.

4. Clarify Administrative Controls for Preventive Maintenance Activities

Section 3.2.10.3 of the SER evaluates the elements of the Preventive Maintenance Activities collectively. In particular, the section states that the corrective actions, confirmation process, and administrative controls for these activities are in accordance with the site quality assurance plan pursuant to 10 CFR Part 50, Appendix B. As noted in Inspection Report IR 99-12, Section E.8.3.p.1, many of the activities in the Preventive Maintenance Activities program are performed on non-safety equipment and are not controlled by the site quality assurance program. The corrective actions, confirmation process, and administrative controls elements for the Preventive Maintenance Activities should be evaluated for the individual activities given the information provided on these activities in response to RAI 4.3.8-1. For more information on

control of non-safety equipment within license renewal aging management programs, see response to SER Open Item 3.2.3.3-1

5. Clarify Discussion of Auxiliary Service Water

At the time the technical documentation was being developed to support the Oconee License Renewal Application, there was a misunderstanding about the normal system alignment of the Auxiliary Service Water (ASW) System. This system is normally in a standby mode with parts of the system normally wetted and other parts normally dry and exposed to an internal air environment. This misunderstanding caused the environment/ aging effect/ aging management program information in the Application to be misconstrued. The ASW System is depicted on OLRFD 121D-1.2. The portion of the system upstream of valve CCW-101 is normally exposed to raw water. This portion of the system contains pipe, valves, tubing, an annubar tube, and the ASW pump. The portion of the system downstream of CCW-101 is normally exposed to air because drain valve CCW-309 is normally open. At one time, the portion of the system now exposed to air did contain stagnant, raw water, but a change in valve alignment a few years ago to leave CCW-309 normally open caused this portion of the system to be drained and exposed the internal environment of the piping to air. This portion of the system contains pipe and valves.

5.1 Raw Water Portion of the System

The aging effects in the raw water portion of the system are loss of material and fouling. Fouling is managed by System Performance Testing Activities, as stated in Application Section 3.5.6.2.3 and Table 3.5-4. Table 4.3-1 of the Application incorrectly lists fouling as being managed by the *Auxiliary Service Water Piping Inspection* of the Preventive Maintenance Activities. Inclusion of this program name in the table is an error and should be disregarded. System Performance Testing Activities alone are credited with managing fouling in the raw water portion of the Auxiliary Service Water System.

Loss of material in the raw water portion of the system is managed by the Service Water Piping Corrosion Program, as stated in Application Section 3.5.6.2.3 and Table 3.5-4. It was noted in Inspection Report 99-12 that the Service Water Piping Corrosion Program inspection location in this system is located at the discharge of valve CCW-101, not at the pump discharge check valve. At the time the inspection location was chosen, the location was expected to be a susceptible location because the piping did contain stagnant, raw water. Since the valve realignment, however, the piping now normally contains air and the inspection location is no longer useful.

As pointed out in the Application, the Service Water Piping Corrosion Program is not a system-specific program and performs ultrasonic testing across a number of raw water systems at sample locations of various flow regimes. The program does contain inspection location points of carbon steel piping in stagnant portions of other raw water systems which will provide information to allow aging management of the similar materials in the raw water portion of the

Auxiliary Service Water System. The staff review of the Service Water Piping Corrosion Program is provided in Section 3.2.13 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of the Open Items identified, the applicant has demonstrated that the Service Water Piping Corrosion Program will adequately manage the aging effects associated with a loss of material from corrosion for those systems that have components exposed to a raw water environment for the period of extended operation. Duke believes the staff's conclusion supports the concept of the Service Water Piping Corrosion Program covering the full range of materials and flow regimes in the raw water systems. Elimination of this ASW location does not invalidate this concept , since similar materials and flow regimes are covered elsewhere within the program.

5.2 AIR PORTION OF THE SYSTEM

The aging effect in the air portion of the system is loss of material. The Preventive Maintenance Activity that is credited in Application Section 3.5.6.2.3 and Table 3.5-4 and expanded upon in response to RAI 4.3.8-1 (12/14/98) as the *Auxiliary Service Water Piping Inspection* was credited for managing loss of material of the components exposed to air. The activity involves a visual inspection of the interior of the pipe when check valve CCW-100 is disassembled. The RAI response reads, "Conditions at this location make it a leading indicator of the condition of the piping that is normally opened to atmosphere downstream of the closed pump discharge isolation valve."

As can be seen from OLRFD 121D-1.2, the location of CCW-100 is not in the portion of the system normally exposed to air. The visual inspection, therefore, does not provide any additional oversight related to the air portion of the system than that which the *Service Water Piping Corrosion Program* provides. The loss of material of the components in an air environment are applicable because of the components' possible exposure to moisture from the raw water portion of the system. Therefore, the aging effects are expected to be most prominent in the raw water portion of the system and sampling those locations would serve as a leading indicator of the air portion of the system. The Service Water Piping Corrosion Program can therefore be credited with managing aging of all system components, both those exposed to raw water and to the less susceptible ones exposed normally to an air environment.

The original commitment to perform the *Auxiliary Service Water Piping Inspection* as part of the Preventive Maintenance Activities is withdrawn. Duke has determined that the *Service Water Piping Corrosion Program* is effective in managing loss of material for the components in the Auxiliary Service Water System.

The following is a revised excerpt of Table 3.5-4 of the Application that shows the component/ material/ environment/ aging effects/ aging management program combinations for the entire Auxiliary Service Water System.

Updated Portion of Application Table 3.5-4
for the Auxiliary Service Water System

MECHANICAL COMPONENT	MATERIAL	INTERNAL ENVIRONMENT	APPLICABLE AGING EFFECTS	AGING MANAGEMENT PROGRAM/ACTIVITY
Auxiliary Service Water System				
Annubar Tube	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	System Performance Testing Activities
Pipe	Carbon Steel	Air	Loss of Material	Service Water Piping Corrosion Program
Pipe	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	System Performance Testing Activities
Pipe	Stainless Steel	Air	Loss of Material	Service Water Piping Corrosion Program
Pipe	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	System Performance Testing Activities
Pump Casing	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection Cast Iron Selective Leaching Inspection
Tubing	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	System Performance Testing Activities
Valve Bodies	Carbon Steel	Air	Loss of Material	Service Water Piping Corrosion Program
Valve Bodies	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
			Fouling	System Performance Testing Activities
Valve Bodies	Stainless Steel	Air	Loss of Material	Service Water Piping Corrosion Program
Valve Bodies	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			Fouling	System Performance Testing Activities

6. Clarify Discussion of Cast Austenitic Stainless Steel (CASS)

Section 3.4.3.3 (starting on page 3-110) of the SER discusses embrittlement of CASS reactor vessel internals items. This discussion needs to be revised to reflect the discussion held between Duke and the staff during a meeting on August 24, 1999 and as provided in our response to SER Open Item 3.4.3.3-5.

7. Revise the Evaluation of the Chemistry Control Program

The staff's evaluation of the Chemistry Control Program is contained in Section 3.2.2 of the SER. The staff's evaluations of the SSF Fuel Oil Surveillances, which are described in Section 4.6.5 of Exhibit A of the Application, are not included in its SER.

8. Revise the Description of the "Technical Information for Identifying Systems, Structures, and Components within the Scope of License Renewal"

The staff's description of the "Technical Information for Identifying Systems, Structures, and Components within the Scope of License Renewal" is presented in Section 2.1.2.1 of the SER. This section does not include the description of several important features of the Oconee scoping methodology. These features are described in Section 2.2 of Exhibit A of the Application. Additional information was provided in Duke letter dated March 18, 1999 and June 22, 1999 relative to the mechanical system scoping features. As a convenience to the staff, these important features are summarized below:

1. All mechanical systems and their functions that are listed in Oconee event mitigation calculations are included within the scope of license renewal. (The scope of these events is the subject of SER Open Item 2.1.3.1-1.)
2. All passive pressure boundaries required for mechanical systems identified in Feature 1 above are included within the scope of license renewal.
3. Portions of selected mechanical systems whose failure to maintain their pressure boundary or to remain structurally intact would result in impacting the function of any essential system and component (seismic II/I) are included within the scope of license renewal.
4. Mechanical systems or portions of systems that contain safety-related and seismically designed piping that have not otherwise been included are included within the scope of license renewal.
5. All Oconee structures that are designated as either Class 1 or 2 are included within the scope of license renewal.
6. All Oconee electrical components are initially assumed to be within the scope of license renewal.
7. All structures and mechanical systems required to demonstrate compliance with NRC regulations for events identified in §54.4(a)(3) are included within the scope of license renewal.

Because the staff's description of the entire Oconee scoping methodology requires revision as described above, it follows that its evaluation presented in Section 2.1.3 of the SER, "Evaluation of the Methodology for Identifying Systems, Structures and Components within the Scope of License Renewal" likewise needs to be revised to include its evaluation of these important features of the Oconee scoping methodology.

9. Verify the Appropriateness of Specifically Referencing Documents that are not Part of the Application

Several Oconee engineering documents were reviewed by the staff in support of its review of the Oconee Application that was submitted in July 1998. These engineering documents are specifically referenced in Sections 2.1.2.2 and 4.2.8.3 of the SER, yet they are not docketed. Duke believes that they should not be specifically referenced in the SER as to do so would seem to imply that the documents are part of the Application, which they are not. The staff should verify the appropriateness of including these specific references in the Oconee SER.

10. Revise Discussion of Class E Piping Supports

Class E pipe supports were inadvertently omitted from the scope of license renewal during development of the substantiating information for the application. The application incorrectly states that Class E piping is not within the scope of license renewal. The information should be changed to include Class E pipe supports which are required for seismic structural integrity. The first complete paragraph on Page 2.7-7 of Exhibit A of the Application should be deleted and the discussion concerning Class E piping supports in the second paragraph on Page 2.7-7 of the Application should be revised to read as follows:

Duke Class E, G and H piping supports may be assigned QA Condition 4 to denote requirements for seismic structural integrity to prevent adverse interactions with safety related systems, structures, and components. Duke Class E, G and H pipe supports, which are QA Condition 4, are within license renewal scope.

Attachment 2

Responses to Safety Evaluation Report
Open Items

October 15, 1999

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

Once the information identified in item 1 above is provided, the staff will determine whether additional inspection activities will be needed to verify that there is reasonable assurance that the Oconee systems, structures and components that are within scope of the license renewal rule have been captured by the applicant's process. This is part 2 of the Open Item.

Duke Response to SER Open Item 2.1.3.1-1
Duke letter dated June 22, 1999 to the NRC (Document Control Desk) provided the initial response to this SER Open Item.

NRC letter dated October 8, 1999 provided a plan for the resolution of this scoping issue. Duke is in the process of reviewing this letter and will work with Joe Sebrosky of the staff to arrange a meeting to discuss the information needs described in the letter.

SER Open Item 2.2.3-1 – Since the RCW system is relied upon to supply cooling water to the SFP cooling system coolers to maintain the bulk SFP coolant temperature below the SFP design limits and below assumptions for the fuel handling accident analysis described in Section 15.11.2.1 of the UFSAR, the staff believes that this system should be included within the scope of license renewal based on the criteria of 10 CFR 54.4 (a)(1)(iii) and its components subject to an AMR in accordance with the requirements of 10 CFR 54.21.

Duke Response to SER Open Item 2.2.3-1
The fuel handling accident analysis assumes that spent fuel cooling, and thus the Recirculated Cooling Water System, is not functional during or following the event. The safety analysis acceptance criteria of the fuel handling accident in Section 15.11 of the UFSAR demonstrates that resultant consequences of the accident remain within 10 CFR 100 guidelines. The initial spent fuel pool temperature established by normal operating procedures ensures that the safety analysis does not require cooling to mitigate the accident. License renewal scoping criteria of §54.4(a)(1)(iii) requires that systems and components required to remain functional during and following design basis events to prevent or mitigate the consequences that could result in potential offsite exposure comparable to 10 CFR Part 100 guidelines be within scope. Since spent fuel cooling is not required to remain functional during or following the fuel handling accident to prevent or mitigate the consequences that could result in potential offsite exposure comparable to 10 CFR Part 100 guidelines, the systems and components required to fulfill the function of spent fuel cooling, including the Recirculated Cooling Water System, are not within the scope of license renewal.

SER Open Item 2.2.3.4.3.2.1-1 – Also in the May 10,1999, letter, the applicant provides reasons why the Chilled Water System (CWS) (which supports the cooling function for the CRPFS) is not included within the scope of license renewal. The applicant states that for certain design-basis events, the CRPFS maintains a positive pressure in the control room and that air conditioning is not required. The applicant states that failure of the CWS does not prevent the CRFPS from maintaining a positive pressure in the control room for accident conditions and is not classified Oconee Piping Class D for seismic II/I concerns. Further, the applicant stated that the CRFPS is credited with maintaining a suitable environment in the control room during a fire event and providing for smoke removal from the control room, neither of which require air conditioning supported by the CWS system. The applicant also noted that the CRPFS and the supporting CWS do not perform an intended function in support of any other regulated event listed in 10 CFR 54.4(a)(3). The applicant concludes from this evaluation that the CWS is not within the scope of license renewal. The staff does not agree with this conclusion. It appears to the staff that the CWS is needed at ONS in order to assure the capability to shutdown the reactor and maintain it in a shutdown condition. The applicant should identify where in the current licensing basis the loss of the CWS has been addressed, and clarify why the CWS is not within the scope of license renewal and subject to an aging management review.

Duke Response to SER Open Item 2.2.3.4.3.2.1-1
The requirement to have an installed Chilled Water System that can withstand a single active failure is addressed in UFSAR 3.11.4. The Chilled Water system has also recently been added to the current licensing basis of Oconee via Improved Technical Specification (ITS) implementation. Improved Technical Specifications, which were implemented March 27, 1999, includes a new requirement in section 3.7.16 to have two trains of Chilled Water operable. The Chilled Water System is used to maintain control room and control area temperatures within ITS prescribed limits. While the Chilled Water System is addressed in the Oconee current licensing basis, a Loss of Chilled Water System event is not addressed in the Oconee current licensing basis.

License renewal scoping criteria requires that systems, structures, and components (SSCs) relied upon to remain functional during and following design basis events, SSCs whose failure could prevent satisfactory function of the aforementioned, and SSCs whose function is required to demonstrate compliance with certain regulations, be included within scope. The Chilled Water System is a non-safety related system and engineering analysis shows that its loss of function during a design basis event can be withstood for 24 hours, upon which time several options of compensatory actions exist. As stated in Oconee Nuclear Station Licensee Event Report 287/1998-06, "The compensatory actions are simple in that air circulation can be established by opening doors and positioning dampers. The actions do not require complicated engineering analyses or detailed logistics to complete." Based on the engineering analysis, the Chilled Water System has historically not been included in other regulated programs as a system relied upon to support design basis event mitigation.

Notwithstanding the above, Duke now commits to including the Chilled Water System within the scope of license renewal. As a consequence of adding the Chilled Water System, integrated plant assessments have been performed on the following:

- Chilled Water System
- Condenser Circulating Water System (portion added)
- Control Room Pressurization and Filtration (portion added)

1. Chilled Water System – Integrated Plant Assessment

1.1 MECHANICAL COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

The Chilled Water System provides chilled water to various cooling coils in the Control Room Pressurization and Filtration Systems to provide temperature control for the control areas. The license renewal portions of the Chilled Water System are designed and constructed to the requirements of Oconee Piping Class G. Class G piping and components are <u>not</u> designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction of this system are brass, carbon steel, cast iron, copper, galvanized steel and stainless steel. The tubes of the heat exchanger in the refrigeration unit are constructed of copper. The Chilled Water System components that are subject to aging management review are listed in Table 1.

1.2 AGING MANAGEMENT REVIEW

1.2.1 Environments

The internal surfaces of the Chilled Water System are exposed to air, raw water, treated water and refrigerant in the refrigeration loop. The potential aging effects for materials exposed to air, raw water, and treated water are discussed in Sections 3.5.2.1, 3.5.2.4, and 3.5.2.5 of Exhibit A of the Application. The aging effects for refrigerant are discussed below.

The external surfaces are exposed to the sheltered environment of the Auxiliary Building and Turbine Building. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

1.2.2 Applicable Aging Effects

The materials of construction of this system are brass, carbon steel, cast iron, copper, galvanized steel, glass and stainless steel. The tubes of the heat exchanger in the refrigeration unit are constructed of copper. The applicable aging effect for carbon steel components in an air environment is loss of material. The staff review of the aging effects of materials exposed to air is provided in Section 3.1.3.1.1 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The applicable aging effects for the components constructed of carbon steel exposed to raw water are loss of material and fouling. The staff review of the aging effects of materials exposed to raw water is provided in Section 3.1.3.1.4 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The applicable aging effect for the components constructed of brass, carbon steel, cast iron, copper and galvanized steel exposed to treated water is loss of material. The applicable aging effects for stainless steel components exposed to treated water are loss of material and cracking. No applicable aging effects were identified for glass in treated water. The staff review of the aging effects of materials exposed to treated water is provided in Section 3.1.3.1.5 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The review to identify applicable aging effects for glass and for materials exposed to refrigerant have not been previously reviewed by the staff. Duke has performed a review to identify the aging effects for glass and refrigerant using the methodology described in Section 3.5.2 of Exhibit A of the Application. Based on this review, Duke has determined that there are no applicable aging effects for glass or for any material exposed to refrigerant.

The exterior surfaces of the Chilled Water System are exposed to a sheltered environment. The applicable aging effect for components constructed of brass, carbon steel, cast iron, copper, or galvanized steel exposed to a sheltered environment is loss of material. No applicable aging effects exist for the stainless steel components or glass exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

1.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the Chilled Water System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following programs and activities will manage the aging effects of the Chilled Water System for the period of extended operation:

- Boric Acid Wastage Surveillance Program
- Cast Iron Selective Leaching Inspection
- Chemistry Control Program
- Chilled Water System Refrigeration Unit Preventive Maintenance Activity (New)

- Galvanic Susceptibility Inspection
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (as modified)
- Treated Water Stainless Steel Inspection

The above programs and activities are described in the following paragraphs.

1.2.3.1 BORIC ACID WASTAGE SURVEILLANCE PROGRAM

Loss of material due to boric acid wastage is an aging effect for components constructed of brass, carbon steel, cast iron, copper, and galvanized steel located in the Auxiliary Building. This aging effect will be managed by the Boric Acid Wastage Surveillance Program, which is described in Section 4.5 of Exhibit A of the Application. The staff review of the Boric Acid Wastage Surveillance Program is provided in Section 3.2.1 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Chilled Water System.

1.2.3.2 CAST IRON SELECTIVE LEACHING INSPECTION

For loss of material of cast iron components, the Cast Iron Selective Leaching Inspection described in Section 4.3.2 of Exhibit A of the Application will manage the applicable aging effects for all components including those added to the scope of license renewal. This is a scope addition to this activity. The staff review of the Cast Iron Selective Leaching Inspection is provided in Section 3.2.8 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Chilled Water System.

1.2.3.3 CHEMISTRY CONTROL PROGRAM

For loss of material in the components constructed of brass, carbon steel or copper exposed to treated water and the portion of the carbon steel tank exposed to air, the Chemistry Control Program described in Section 4.6 of Exhibit A of the Application will manage the applicable aging effects for all components including those added to the scope of license renewal. The staff review of the Chemistry Control Program is provided in Section 3.2.2 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Chilled Water System.

1.2.3.4 CHILLED WATER SYSTEM REFRIGERATION UNIT PREVENTIVE MAINTENANCE ACTIVITY (NEW)

The purpose of Chilled Water System Refrigeration Unit Preventive Maintenance Activity is to manage fouling of the condensing heat exchanger exposed to raw water and loss of material of the tubes exposed to raw water. This activity is described below using the program/ activity attributes described in Section 4.2 of Exhibit A of the Application.

1.2.3.5 Galvanic Susceptibility Inspection

Loss material of portions of the Chilled Water System exposed to raw water will be managed by the Galvanic Susceptibility Inspection. This activity is described in Section 4.3.3 of Exhibit A of the Application. The staff review of the Galvanic Susceptibility Inspection is provided in Section 3.2.9 Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the Galvanic Susceptibility Inspection will adequately manage the aging effects associated with loss of material due to corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

1.2.3.6 Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the Auxiliary Building and Turbine Building. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

1.2.3.7 Service Water Piping Corrosion Program

The Service Water Piping Corrosion Program will manage the loss of material due to general corrosion, pitting corrosion, and microbiologically influenced corrosion of the carbon steel components exposed to a raw water environment. This program is described in Section 4.25 of Exhibit A of the Application and subsequently modified by the collective Duke response to Safety Evaluation Report (June 1999) Open Items 3.2.13-1, 3.2.13-2, 3.2.13-3 and 3.2.13-4. The staff review of the Service Water Piping Corrosion Program is provided in Section 3.2.13 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of the Open Items identified, the applicant has demonstrated that the Service Water Piping Corrosion Program will adequately manage the aging effects associated with a loss of material from corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

1.2.3.8 Treated Water Stainless Steel Inspection

Cracking in the stainless steel components exposed to treated water will be managed by the Treated Water Systems Stainless Steel Inspection as described in Section 4.3.13 of Exhibit A of the Application. The staff review of the Treated Water Systems Stainless Steel Inspection is provided in Section 3.2.11 Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the Treated Water Systems Stainless Steel Inspection will adequately manage the aging effects associated with cracking of components exposed to a treated water environment for the period of extended operation.

Table 1

Aging Management Review Summary - Chilled Water System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Compressor	Pressure Boundary	Cast Iron	Refrigerant	None Identified	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Cooling Coil Tube	Pressure Boundary Heat Transfer	Copper	Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building)	Loss of Material	Boric Acid Wastage Surveillance Program
Cooling Coil Header	Pressure Boundary	Galvanized steel	Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building)	Loss of Material	Boric Acid Wastage Surveillance Program
Condensing Heat Exchanger Channel	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
				Fouling	Chilled Water System Refrigeration Unit Preventive Maintenance Activity (New)
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Condensing Heat Exchanger Shell	Pressure Boundary	Carbon Steel	Refrigerant	None Identified	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components

Table 1
Aging Management Review Summary - Chilled Water System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Condensing Heat Exchanger Tube	Pressure Boundary Heat Transfer	Copper	Raw Water	Loss of Material	Chilled Water System Refrigeration Unit Preventive Maintenance Activity (New)
				Fouling	Chilled Water System Refrigeration Unit Preventive Maintenance Activity (New)
			(Refrigerant)	None Identified	None Required
Condensing Heat Exchanger Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
				Fouling	Chilled Water System Refrigeration Unit Preventive Maintenance Activity (New)
			(Refrigerant)	None Identified	None Required
Evaporator Heat Exchanger Channel	Pressure Boundary	Carbon steel	Treated Water	Loss of Material	Chemistry Control Program
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Evaporator Heat Exchanger Shell	Pressure Boundary	Carbon Steel	Refrigerant	None Identified	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Evaporator Heat Exchanger Tube	Pressure Boundary Heat Transfer	Copper	Treated Water	Loss of Material	Chemistry Control Program
			(Refrigerant)	None Identified	None Required
Evaporator Heat Exchanger Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(Refrigerant)	None Identified	None Required

Table 1
Aging Management Review Summary - Chilled Water System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Orifice	Pressure Boundary	Stainless Steel	Treated Water	Loss of Material Cracking	Chemistry Control Program Treated Water Systems Stainless Steel Inspection
			(Refrigerant)	None Identified	None Required
			(Auxiliary Building)	None Identified	None Required
Pipe	Pressure Boundary	Carbon steel	Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building, Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components Boric Acid Wastage Surveillance Program
Pump Casing	Pressure Boundary	Cast Iron	Treated Water	Loss of Material	Chemistry Control Program Cast Iron Selective Leaching Inspection
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Sight Glass	Pressure Boundary	Glass	Treated Water	None Identified	None Required
			(Turbine Building)	None Identified	None Required
Strainers	Pressure Boundary	Cast Iron (Body)	Treated Water	Loss of Material	Chemistry Control Program Cast Iron Selective Leaching Inspection
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
	None	Stainless Steel (Basket)	Treated Water	Not Applicable due to no component function	Not Applicable due to no component function
Tank	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			Air	Loss of Material	Chemistry Control Program
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components

Table 1
Aging Management Review Summary - Chilled Water System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Tubing	Pressure Boundary	Brass	Refrigerant	None Identified	None Required
			Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building, Turbine Building)	Loss of Material	Boric Acid Wastage Surveillance Program
		Carbon steel	Refrigerant	None Identified	None Required
			Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building, Turbine Building)	Loss of Material	Boric Acid Wastage Surveillance Program Inspection Program for Civil Engineering Structures and Components
		Copper	Refrigerant	None Identified	None Required
			Treated Water	Loss of Material	Chemistry Control Program
			(Auxiliary Building, Turbine Building)	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Refrigerant	None Identified	None Required
			Treated Water	Loss of Material Cracking	Chemistry Control Program Treated Water Systems Stainless Steel Inspection
			(Auxiliary Building, Turbine Building)	None Identified	None Required
Valve Bodies	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			Refrigerant	None Identified	None Required
			(Auxiliary Building, Turbine Building)	Loss of Material	Boric Acid Wastage Surveillance Program Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Treated Water	Loss of Material Cracking	Chemistry Control Program Treated Water Systems Stainless Steel Inspection
			Refrigerant	None Identified	None Required
			(Auxiliary Building, Turbine Building)	None Identified	None Required

CHILLED WATER SYSTEM REFRIGERATION UNIT PREVENTIVE MAINTENANCE ACTIVITY (NEW)

Purpose – The purpose of Chilled Water System Refrigeration Unit Preventive Maintenance Activity is to manage fouling of the condensing heat exchanger exposed to raw water and loss of material of the tubes exposed to raw water.

Scope – The portion exposed to raw water in the condensing heat exchangers of the refrigeration unit are addressed by this activity.

Aging Effects – Loss of material of the tubes and fouling of the channel heads, tube sheets, and tubes.

Method – 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 include inlet and outlet temperatures along with refrigerant pressures.

Sample Size – Not applicable for an existing activity.

Industry Codes and Standards – No code or standard exists to guide or govern this activity.

Frequency – This activity is performed quarterly.

Acceptance Criteria – Inlet and outlet operating temperatures and refrigerant pressures are within the acceptable operating ranges.

Corrective Action – 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.

Timing of New Program Initiation – The Chilled Water System Refrigeration Unit Preventive Maintenance Activity is an existing activity that will be continued into the extended period of operation.

Administrative Control – The Chilled Water System Refrigeration Unit Preventive Maintenance Activity is implemented by a controlled plant procedure.

Regulatory Basis – No regulatory basis exists for this activity.

2. Condenser Circulating Water System – Integrated Plant Assessment

2.1 MECHANICAL COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

A portion of the Condenser Circulating Water System has been added to the scope of license renewal due to the addition of the Chilled Water System. The Condenser Circulating Water System provides cooling water to the Recirculating Water Coolers and Control Room Ventilation Chillers. The portion of the Condenser Circulating Water System that has been added is designed to the requirements of Oconee Piping Class G. Class G piping and components are not designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction for the components of the portion of the Condenser Circulating Water System that has been added are brass, cast iron, carbon steel, copper, and stainless steel. The Condenser Circulating Water System components that are subject to aging management review are listed in Table 2.

2.2 AGING MANAGEMENT REVIEW

2.2.1 Environments

The internal surfaces of the portions of the Condenser Circulating Water System added due to the addition of the Chilled Water System are exposed to raw water. The potential aging effects for components exposed to raw water are discussed in Section 3.5.2.4 of Exhibit A of the Application.

The external surfaces of the portions of the Condenser Circulating Water System added due to the addition of the Chilled Water System are exposed to the sheltered environment of the Turbine Building. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

2.2.2 Applicable Aging Effects

The materials of construction for the components of the portion of the Condenser Circulating Water System that have been added are brass, cast iron, carbon steel, copper, and stainless steel. The applicable aging effects for components exposed to raw water is loss of material. Piping in the portions of the Condenser Circulating Water System that have been added are greater than or equal to six-inches in diameter. Therefore, fouling is not likely to cause a loss of system function and therefore does not require aging management. The staff review of the aging effects of materials exposed to raw water is provided in Section 3.1.3.1.4 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The exterior surfaces of the components of the portion of the Condenser Circulating Water System that was added are exposed to a sheltered environment. The applicable aging effect for components constructed of carbon steel, or cast iron exposed to a sheltered environment is loss of material. No applicable aging effects exist for the brass, copper and stainless steel components

exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

2.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the portion of the Condenser Circulating Water System that were added will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following programs and activities will manage the aging effects of the portion of the Condenser Circulating Water System that was added:

- Cast Iron Selective Leaching Inspection
- Galvanic Susceptibility Inspection
- Inspection Program for Civil Engineering Structures and Components
- Service Water Piping Corrosion Program (as modified)

The above programs and activities are described in the following paragraphs.

2.2.3.1 CAST IRON SELECTIVE LEACHING INSPECTION

For loss of material of cast iron components, the Cast Iron Selective Leaching Inspection described in Section 4.3.2 of Exhibit A of the Application will manage the applicable aging effects for all components including those added to the scope of license renewal. The staff review of the Cast Iron Selective Leaching Inspection is provided in Section 3.2.8 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the portion of the Condenser Circulating Water System that was added.

2.2.3.2 GALVANIC SUSCEPTIBILITY INSPECTION

Loss material of portions of the Condenser Circulating Water System exposed to raw water will be managed by the Galvanic Susceptibility Inspection. This activity is described in Section 4.3.3 of Exhibit A of the Application. The staff review of the Galvanic Susceptibility Inspection is provided in Section 3.2.9 Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the Galvanic Susceptibility Inspection will adequately manage the aging effects associated with loss of material due to corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

2.2.3.3 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the Turbine Building. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

2.2.3.4 SERVICE WATER PIPING CORROSION PROGRAM

The Service Water Piping Corrosion Program will manage the loss of material due to general corrosion, pitting corrosion, and microbiologically influenced corrosion of the carbon steel components exposed to a raw water environment. This program is described in Section 4.25 of Exhibit A of the Application and subsequently modified by the collective Duke response to Safety Evaluation Report (June 1999) Open Items 3.2.13-1, 3.2.13-2, 3.2.13-3 and 3.2.13-4. The staff review of the Service Water Piping Corrosion Program is provided in Section 3.2.13 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of the Open Items identified, the applicant has demonstrated that the Service Water Piping Corrosion Program will adequately manage the aging effects associated with a loss of material from corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

Table 2

Aging Management Review Summary – Condenser Circulating Water System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Flexible Hose	Pressure Boundary	Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
				Fouling	None Required
			(Turbine Building)	None Identified	None Required
Pipe	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility
				Fouling	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Pump Casing	Pressure Boundary	Cast Iron	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Cast Iron Selective Leaching Inspection
				Fouling	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components

Table 2
Aging Management Review Summary – Condenser Circulating Water System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Strainers	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water piping Corrosion Program Galvanic Susceptibility Inspection
				Fouling	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
	None	Stainless Steel (Basket)	Raw Water	Not Applicable	Not Applicable
Tubing	None	Brass Carbon Steel Copper Stainless Steel	Raw Water	None Identified	None Required
			(Turbine Building)	None Identified	Inspection Program for Civil Engineering Structures and Components (Carbon steel only)
Valve Bodies	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
				Fouling	None Required
			(Turbine Building)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program
			(Turbine Building)	None Identified	None Required

3. Control Room Pressurization and Filtration – Integrated Plant Assessment

3.1 MECHANICAL COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

Portions of the Control Room Pressurization and Filtration System have been added to the scope of license renewal due to the addition of the Chilled Water System. The function of the portions of the Control Room Pressurization and Filtration System that have been added is to maintain a suitable environment within acceptable limits in the Control Room after postulated design basis events. The materials of construction for the portions of the Control Room Pressurization and Filtration System that have been added are aluminum, brass, carbon steel, copper, galvanized steel, and stainless steel. The Control Room Pressurization and Filtration System components that are subject to aging management review are listed in Table 3.

3.2 AGING MANAGEMENT REVIEW

3.2.1 Environments

The internal surfaces of the added portions of the Control Room Pressurization and Filtration System are exposed to ventilation air. The potential aging effects for materials exposed to ventilation air are discussed in Section 3.5.2.6 of the Application.

The external surfaces of the added portions of the Control Room Pressurization and Filtration System are exposed to the sheltered environment of the Auxiliary Building. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

3.2.2 Applicable Aging Effects

The materials of construction for the portions of the Control Room Pressurization and Filtration System that have been added are aluminum, brass, carbon steel, copper, galvanized steel, and stainless steel. There are no applicable aging effects for these materials when exposed to ventilation air environment. The staff review of the aging effects of materials exposed to ventilation air is provided in Section 3.1.3.1.6 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of SER Open Item 3.1.1-1, the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The applicable aging effect for components constructed of aluminum, brass, carbon steel, copper and galvanized steel exposed to a sheltered environment is loss of material. No applicable aging effects exist for the stainless steel components exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

3.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the Control Room Pressurization and Filtration System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The Boric Acid Wastage Surveillance Program will manage the aging effects of the Control Room Pressurization and Filtration System for the period of extended operation.

The Boric Acid Wastage Surveillance Program is described in Section 4.5 of Exhibit A of the Application. The staff review of the Boric Acid Wastage Surveillance Program is provided in Section 3.2.1 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Control Room Pressurization and Filtration System.

Table 3

Aging Management Review Summary – Control Room Pressurization and Filtration System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Air Handling Unit	Pressure Boundary	Aluminum	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Galvanized Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	None Identified	None Required
Ductwork	Pressure Boundary	Aluminum	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Galvanized Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	None Identified	None Required
Filter	Pressure Boundary Fitration	Aluminum	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Galvanized Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	None Identified	None Required
Grill	Pressure Boundary	Aluminum	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Galvanized Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	None Identified	None Required

Table 3
Aging Management Review Summary – Control Room Pressurization and Filtration System
(continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Tubing	Pressure Boundary	Brass	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Carbon Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program Inspection Program for Civil Engineering Structures and Components
		Copper	Ventilation Air	None Identified	None Required
			Auxiliary Building	Loss of Material	Boric Acid Wastage Surveillance Program
		Stainless Steel	Ventilation Air	None Identified	None Required
			Auxiliary Building	None Identified	None Required

SER Open Item 2.2.3.4.3.2.1-2 – Regarding the sealant materials associated with the control room pressurization and filtration system, the staff concludes that the condition monitoring provided by the referenced Oconee ITS surveillance does not, by itself, provide a plant-specific basis for excluding the sealant materials in the CRPFS from an aging management review. However, the staff believes that the ITS surveillance, in conjunction with related system inspections and the corrective action process, can provide an adequate aging management program for the sealant materials in the CRPFS system.

Duke Response to SER Open Item 2.2.3.4.3.2.1-2
Duke does not define materials such as caulking, sealants, and waterstops to be structures or components. However, Duke recognizes that limited situations may exist where these materials are important in maintaining the integrity of the components to which they are connected.

The license renewal structure or component intended functions supported by these materials are limited to three functions. These functions are:

1. Maintaining pressure boundary. This function is limited to the control room.
2. Providing a rated fire barrier. Sealants and caulking that support this function are addressed as part of the fire barrier penetration seals in the Oconee License Renewal Application. Fire barrier penetration seals are discussed in Sections 2.7.2.4 and 3.7.2.4 of Exhibit A of the Application. Aging of the fire barrier penetration seals is managed by the Oconee Fire Protection Program that is discussed in Section 4.16 of Exhibit A of the Application.
3. Providing a flood barrier. Caulking, sealants, and waterstops that support this function are limited to those contained in structures whose function is to provide a flood barrier. This function is identified as function #8 in the tables in Section 2.7 of Exhibit A of the Application. Specifically, the Auxiliary Buildings and the Standby Shutdown Facility are identified as providing internal/external flood barriers.

Sealants associated with the control room pressure boundary are addressed below. Caulking, sealants, and waterstops that support the flood barrier function are addressed in SER Open Item 2.2.3.6.1.2.1-1. To maintain the control room at a positive pressure during certain design basis events, the control room boundary and the Control Room Pressurization and Filtration System components outside the control room boundary must remain intact during the pressurization mode (emergency) of operation.

The control room boundary includes the walls, ceiling, floor, access doors, and penetrations for electrical and mechanical equipment. Aging of the control room boundary walls, ceiling, and floor is managed by the Inspection Program of Civil Engineering Structures and Components. This program is presented in Section 4.19 of Exhibit A of the Application. The access doors and penetrations are fire barriers in the control room boundary. Aging of the access doors and the fire retardant sealant in the penetrations is managed by the Fire Barrier Inspection of the Fire Protection Program. The Fire Protection Program is presented in Section 4.16 of Exhibit A of the Application.

Aging of the Control Room Pressurization and Filtration System sealant materials will be managed by the Control Room Ventilation System Examination that is required by Oconee Technical Specification Surveillance Requirement 3.7.9.1. The Control Room Ventilation System Examination is described below using the program attributes described in Section 4.2 of Exhibit A of the Application. Note that this examination also serves to manage the aging of the rubber boots, seals, and flexible collars of the Control Room Pressurization and Filtration System discussed in SER Open Item 3.6.1.3.1-1.

CONTROL ROOM VENTILATION SYSTEM EXAMINATION ATTRIBUTES

Purpose – The purpose of the Control Room Ventilation System Examination is to determine the condition of the external surfaces of the Control Room Pressurization and Filtration System components, including seals, sealants, rubber boots, and flexible collars.

Scope – Rubber boots, seals, sealant materials, and flexible collars are examined when the component that they are a part of is examined.

Aging Effects – Cracking of components and degradation of sealing materials

Method – A visual inspection of the exterior surfaces of the Control Room Pressurization and Filtration System components, including seals, sealants, rubber boots, and flexible collars.

Sample Size – Not applicable for an existing activity.

Industry Codes and Standards – No code or standard exists to guide or govern this examination.

Frequency – This examination is performed quarterly.

Acceptance Criteria – No indications of degradation of seals, sealants, rubber boots, and flexible collars are found.

Corrective Action – 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.

Timing of New Program Initiation – The Control Room Ventilation System Examination is an existing surveillance activity that will be continued into the extended period of operation.

Administrative Control – The examination is implemented by a controlled plant procedure.

Regulatory Basis – The examination is implemented in response to Oconee Technical Specification Surveillance Requirement 3.7.9.1.

SER Open Item 2.2.3.4.8.2.1-1 – During an April 1, 1999, phone conference, the applicant was asked to clarify why portions of the diesel fuel oil system and starting air system were not within the highlighted evaluation boundaries. As documented in a phone call summary dated April 13, 1999, the applicant stated that the diesel fuel oil system piping, which leads directly to the diesel oil injectors from the oil day tank, are within the scope of license renewal and, therefore, should have been highlighted on drawing OLRFD-135A-1.2. However, the applicant considers the portion of the diesel fuel oils system and starting air system supplied by the vendor to be excluded from an AMR on the basis of 10 CFR 54.21(a)(1)(i). Further evaluation by the staff revealed that this methodology also excludes the diesel engine jacket water heat exchangers from an AMR because it is part of the vendor-supplied diesel generator skid-mounted equipment. Because they are passive and long-lived, the staff does not agree that these mechanical components can be excluded from an AMR.

10 CFR 54(a)(1)(i) does not provide justification for exclusion taken by the applicant. A review of the SOCs did not identify any guidance that would allow the exclusion taken by the applicant. However, there is guidance provided in NEI 95-10, "Industry Guide for Implementing the Requirements of 10 CFR Part 54 — The License Renewal Rule." In Section 2.5.1 of Exhibit A of the LRA Duke states that "the methodology used to identify the mechanical components subject to aging management review at Oconee is consistent with the guidance provided in NEI 95-10." The exclusion of the diesel engine jacket water heat exchanger, and portions of the diesel fuel oil system, and starting air system, from an AMR have led the staff to determine that the methodology applied by the applicant to its IPA to exclude these components is not consistent with Section 4.1.1, "Establishing Evaluation Boundaries," of NEI 95-10 or Example 5 of Appendix C to NEI 95-10.

Duke Response to SER Open Item 2.2.3.4.8.2.1-1
As Duke understands it, the issue in SER Open Item 2.2.3.4.8.2.1-1 is related to the methodology used by Duke to establish the aging management review boundary for structures and components that may be considered "complex assemblies" by the guidance provided in NEI 95-10. Referring to the idea of a complex assembly, the guidance in NEI 95-10, Section 4.1.1 reads, "An applicant should establish the boundaries for such assemblies by identifying each structure and component that makes up the complex assembly and determining whether or not each structure and component is subject to an aging management review." Further thoughts on this subject are again offered in NEI 95-10 Appendix C, Example 5 which reads, "The purpose of this example is to show how a complex assembly (Reference 4.1.1) evaluation boundary might be determined. It is understood that once the boundary is determined, the long-lived passive components would require an aging management review." Duke agrees with this guidance that the evaluation boundaries among structures and components should be clearly established, though Duke has discovered in its license renewal work that the notion of a complex assembly is not required. The methodology used by Duke in the application to establish the limits of the diesel package evaluation boundary at the vendor-supplied "skid" boundary has been revisited. The following discussion provides the detailed review of the methodology of establishing a structure or component evaluation boundary. The discussion continues by specifically addressing the Standby Shutdown Facility diesel generator

package. Finally, additional applications of this methodology are provided to assure consistency in the Duke work.

The methodology for determining the components subject to an aging management review is presented in Section 2.5.2.2 of Exhibit A of the Application. From this section, the determination of components subject to an aging management review starts with the development of a menu of mechanical components that exist at Oconee. Oconee license renewal flow diagrams and Appendix B of NEI 95-10 were used to develop this menu. Except for pipe and tubing and their associated fittings, components on the menu are uniquely identified with a plant and system specific equipment number. Their boundaries are identified by the plant schematic drawings. For example, a heat exchanger is installed as a unit with inlet and outlet nozzles or flanges and receives a unique equipment number. The boundaries of the heat exchanger are identified on the flow diagrams. Heat exchangers are not purchased by their constituent parts and assembled on site. As a result, Duke does not consider the constituent parts of heat exchangers as unique components that have unique component intended functions for the purposes of license renewal.

From 10 CFR 54.21(a), the Commission listed active components that were exempt from an aging management review. Duke reviewed this list to determine similar characteristics that may exist among these active components, including their "boundary." Evaluation of this list determined that the active components were built as a single enclosure or mounted on a skid. The regulatory exclusion from aging management review applied to items inside the active component enclosure even though these items could independently perform a function if they were applied outside the enclosure as stand alone components. As a result, Duke understands the physical enclosure to be the boundary of these active components. Examples of active components that illustrate this concept of a physical enclosure are battery chargers, power inverters and air compressors.

For the diesel generator, Duke originally drew an "enclosure" around the diesel generator skid and defined the active diesel generator component listed in 10 CFR 54.21(a) to include the hardware on the skid supplied by the diesel vendor. Duke determined that the hardware within the "enclosure" was a part of the diesel generator package and was thus excluded from aging management review. Following a more detailed review of the characteristics of active components provided in the rule, Duke has determined that the drawing of an "enclosure" around the diesel generator skid to determine the active component evaluation boundaries which excludes some mechanical components may go beyond the intent of the Commission.

Based on the application of the active component boundary concept, the evaluation boundaries of the diesel generator component are defined to be at the connections of the engine, turbocharger, air motors, and generator. The support system components outside this evaluation boundary would not be within the scope of the aging management exclusion and would be subject to an aging management review. The components within the systems below are required in support of the diesel generator and, by this redefinition, require an aging management review.

- Air Intake and Exhaust System
- Diesel Jacket Water Cooling System
- SSF Diesel Generator Fuel Oil System
- SSF Diesel Generator Lube Oil System
- Starting Air System

As a result of the revised component boundary definition, additional components are subject to an aging management review. No additional components were added to the Air Intake and Exhaust System since the entire system was subject to an aging management review with the old definition. Additional components in the SSF Diesel Generator Fuel Oil System and the Starting Air System are subject to an aging management review due to the movement of the component boundary from the skid connection to the engine connection. All the components in the Diesel Jacket Water Cooling System and SSF Diesel Generator Lube Oil System that perform a component intended function in support of a license renewal system intended function are subject to an aging management review. The aging management review for these additional components is presented at the end of the response to this Open Item. *(Note: The numbering continues from the integrated plant assessments provided in our response to SER Open Item 2.2.3.4.3.2.1-1.)*

Motors are another component listed in 10 CFR 54.21(a) as active and do not require an aging management review. Some large motors may contain motor air coolers, oil coolers, or both. The motor air coolers cool the air that cools the motor stator. If the motor contains an oil cooler, the cooler cools the lubricating oil within the motor that lubricates and removes heat from the motor bearing. These coolers are typically inside motor enclosure with connections at the motor surface for cooling water system connection. The performance of these items is measured with the performance of the motor. Again, based on the application of the active component boundary concept, the exclusion from an aging management review includes the cooler parts of the motor. Just as the diesel engine block is excluded from an aging management review because it is integral to the engine, the coolers are also excluded because they are integral to the motor and are within the component enclosure boundary. Therefore, Duke has concluded that motor air coolers and oil coolers integral to large motors are part of the motor and are to be excluded from aging management review based on 10 CFR 54.21(a).

4. Diesel Jacket Water Cooling System - Integrated Plant Assessment

4.1 MECHANICAL COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

The Diesel Jacket Water Cooling System removes heat from the Standby Shutdown Facility (SSF) diesel engines when the engines are operating. The system also maintains the engines at standby temperatures when the engines are shutdown. The portions of the Diesel Jacket Water Cooling System piping that are within the scope of license renewal are designed to the requirements of Oconee Piping Class C. Class C piping and components are designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction for components in this system are admiralty brass, carbon steel, stainless steel, and glass. The Diesel Jacket Water Cooling System components that are subject to aging management review are listed in Table 4.

4.2 AGING MANAGEMENT REVIEW

4.2.1 Environments

The internal surfaces of the components of the Diesel Jacket Water Cooling System are primarily exposed to treated water. Portions of the sight glass and the upper portions of the tanks are exposed to air. The inside surfaces of the heat exchanger channel heads and tubes are exposed to raw water. The potential aging effects for materials exposed to treated water, air or raw water environments are discussed in Sections 3.5.2.5, 3.5.2.1, and 3.5.2.4 of Exhibit A of the Application, respectively.

The external surfaces of components of the Diesel Jacket Water Cooling System are exposed to the sheltered environment of the Standby Shutdown Facility (SSF). The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

4.2.2 Applicable Aging Effects

The materials of construction for components in the Diesel Jacket Water Cooling System are admiralty brass, carbon steel, glass, and stainless steel. The applicable aging effect for the components constructed of carbon steel or admiralty brass exposed to treated water is loss of material. The applicable aging effects for stainless steel components exposed to treated water are loss of material and cracking. The staff review of the aging effects of materials exposed to treated water is provided in Section 3.1.3.1.5 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The applicable aging effects for the components constructed of carbon steel or admiralty brass exposed to raw water are loss of material and fouling. The staff review of the aging effects of materials exposed to raw water is provided in Section 3.1.3.1.4 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging

effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The applicable aging effect for carbon steel components in an air environment is loss of material. The staff review of the aging effects of materials exposed to air is provided in Section 3.1.3.1.1 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The review to identify applicable aging effects for glass in air and sheltered environment has not been previously reviewed by the staff. Duke has performed a review to identify the aging effects for glass using the methodology described in Section 3.5.2 of Exhibit A of the Application. Based on this review, Duke has determined that there are no applicable aging effects for glass exposed to either raw water or air/gas.

The exterior surfaces of the Diesel Jacket Water Cooling System are exposed to a sheltered environment. The applicable aging effect for carbon steel components exposed to a sheltered environment is loss of material. No applicable aging effects exist for the stainless steel components exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

4.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the Diesel Jacket Water Cooling System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following programs and activities will manage the aging effects of the Diesel Jacket Water Cooling System for the period of extended operation:

- Chemistry Control Program
- Galvanic Susceptibility Inspection
- Inspection Program for Civil Engineering Structures and Components
- Jacket Water Heat Exchanger Preventive Maintenance Activity (New)
- Service Water Piping Corrosion Program (as modified)
- System Performance Testing Activity
- Treated Water Stainless Steel Inspection

The above programs and activities are described in the following paragraphs.

4.2.3.1 CHEMISTRY CONTROL PROGRAM

For loss of material in the components exposed to treated water and the portion of the tank exposed to air, the Chemistry Control Program described in Section 4.6 of Exhibit A of the Application will manage the applicable aging effects for all components, including those added to the scope of license renewal. The staff review of the Chemistry Control Program is provided in Section 3.2.2 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Diesel Jacket Water Cooling System.

4.2.3.2 GALVANIC SUSCEPTIBILITY INSPECTION

Loss material of portions of the Diesel Jacket Water Cooling System exposed to raw water will be managed by the Galvanic Susceptibility Inspection. This activity is described in Section 4.3.3 of Exhibit A of the Application. The staff review of the Galvanic Susceptibility Inspection is provided in Section 3.2.9.4 Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the Galvanic Susceptibility Inspection will adequately manage the aging effects associated with loss of material due to corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

4.2.3.3 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the Standby Shutdown Facility. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

4.2.3.4 JACKET WATER HEAT EXCHANGER PREVENTIVE MAINTENANCE ACTIVITY (NEW)

The purpose of Jacket Water Heat Exchanger Preventive Maintenance Activity is to manage loss of material of the admiralty brass tubes. This activity is described after Table 4 using the program/ activity attributes described in Section 4.2 of Exhibit A of the Application.

4.2.3.5 SERVICE WATER PIPING CORROSION PROGRAM

The Service Water Piping Corrosion Program will manage the loss of material due to general corrosion, pitting corrosion, and microbiologically influenced corrosion of the carbon steel components exposed to a raw water environment. This program is described in Section 4.25 of Exhibit A of the Application and subsequently modified by the collective Duke response to Safety Evaluation Report (June 1999) Open Items 3.2.13-1, 3.2.13-2, 3.2.13-3 and 3.2.13-4. The staff review of the Service Water Piping Corrosion Program is provided in Section 3.2.13 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of the Open Items identified, the applicant has demonstrated that the Service Water

Piping Corrosion Program will adequately manage the aging effects associated with a loss of material from corrosion for those systems that have components exposed to a raw water environment for the period of extended operation.

4.2.3.6 SYSTEM PERFORMANCE TESTING ACTIVITY

Fouling of the jacket water heat exchanger in the Diesel Jacket Water Cooling System will be managed by the System Performance Testing Activity. This activity for the Diesel Jacket Water Cooling System is identical to the System Performance Testing Activity described in Section 4.27 of Exhibit A of the Application. The staff review of the fouling for similar raw water piping is discussed with the System Performance Testing Activities in Section 3.6.1.3.2 of the Safety Evaluation Report. Based on its review, the staff concluded that, pending acceptable resolution of Safety Evaluation Report Confirmatory Item 3.6.1.3.2-1, the applicant has demonstrated that this type of testing activity will adequately manage fouling in similar components of the SSF Auxiliary Service Water System.

4.2.3.7 TREATED WATER STAINLESS STEEL INSPECTION

Cracking in the stainless steel components exposed to treated water will be managed by the Treated Water Systems Stainless Steel Inspection as described in Section 4.3.13 of Exhibit A of the Application. The staff review of the Treated Water Systems Stainless Steel Inspection is provided in Section 3.2.11.4 Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that the Treated Water Systems Stainless Steel Inspection will adequately manage the aging effects associated with cracking of components exposed to a treated water environment for the period of extended operation.

Table 4

Aging Management Review Summary – Diesel Jacket Water Cooling System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Flexible Hose	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Channel	Pressure Boundary	Carbon Steel	Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
				Fouling	System Performance Testing Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Shell	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Tubing	Pressure Boundary Heat Transfer	Admiralty Brass	Treated Water	Loss of Material	Chemistry Control Program
			(Raw Water)	Loss of Material	Jacket Water Heat Exchanger Preventive Maintenance Activity (New)
				Fouling	System Performance Testing Program
Heat Exchanger Tube Sheets	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			Raw Water	Loss of Material	Service Water Piping Corrosion Program Galvanic Susceptibility Inspection
				Fouling	System Performance Testing Program
Immersion Heater	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components

Table 4
Aging Management Review Summary – Diesel Jacket Water Cooling System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Pipe	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Treated Water	Loss of Material	Chemistry Control Program
				Cracking	Treated Water Stainless Steel Inspection
			(SSF)	None Identified	None Required
Pump Casing	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Sight Glass	Pressure Boundary	Glass	Treated Water	None Identified	None Required
			Air	None Identified	None Required
			(SSF)	None Identified	None Required
Tank	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			Air	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Tubing	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Treated Water	Loss of Material	Chemistry Control Program
				Cracking	Treated Water Stainless Steel Inspection
			(SSF)	None Identified	None Required
Valve Bodies	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Treated Water	Loss of Material	Chemistry Control Program
				Cracking	Treated Water Stainless Steel Inspection
			(SSF)	None Identified	None Required

JACKET WATER HEAT EXCHANGER PREVENTIVE MAINTENANCE ACTIVITY (NEW)

Purpose – The purpose of Jacket Water Heat Exchanger Preventive Maintenance Activity is to manage loss of material of the admiralty brass tubes.

Scope – The portion of the admiralty brass tubes exposed to raw water in the Jacket Water Heat Exchangers are addressed by this activity.

Aging Effects – Loss of material

Method – For the portion of the admiralty brass tubes exposed to raw water in the Jacket Water Heat Exchangers, system parameters of the entire Diesel Jacket Water Cooling System are monitored during diesel engine operation to provide evidence of loss of material. Parameters monitored are system operating temperatures, pressures, and expansion tank levels.

Sample Size – Not applicable for an existing activity.

Industry Codes and Standards – No code or standard exists to guide or govern this activity.

Frequency – This activity is performed quarterly.

Acceptance Criteria – System operating temperatures, pressures, and expansion tank levels of the Diesel Jacket Water Cooling System are within the acceptable operating ranges.

Corrective Action – 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.

Timing of New Program Initiation – The Jacket Water Heat Exchanger Preventive Maintenance Activity is an existing activity that will be continued into the extended period of operation.

Administrative Control – The Jacket Water Heat Exchanger Preventive Maintenance Activity is implemented by a controlled plant procedure.

Regulatory Basis – The Jacket Water Heat Exchanger Preventive Maintenance Activity is implemented in response to Oconee Technical Specification Surveillance Requirement 3.10.1.9.

5. Standby Shutdown Facility (SSF) Fuel Oil System – Integrated Plant Assessment

5.1 Mechanical Components Subject to Aging Management Review

Additional portions of the SSF Fuel Oil System have been added to those previously identified as subject to aging management review. The SSF Fuel Oil System supplies fuel oil to each diesel engine fuel injector for combustion. The fuel also provides cooling of the fuel injector. The system is in operation when the diesel engine is operating. The portions of the SSF Fuel Oil System piping that are within the scope of license renewal are designed to the requirements of Oconee Piping Class C. Class C piping and components are designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction for components in this system are carbon steel, stainless steel, and glass. The SSF Fuel Oil System components that are subject to aging management review are listed in Table 5.

5.2 Aging Management Review

5.2.1 Environments

The internal surfaces of the components of the SSF Fuel Oil System are exposed to fuel oil. The potential aging effects for components exposed to fuel oil are discussed in Section 3.5.2.3 of Exhibit A of the Application. The external surfaces of components of the SSF Fuel Oil System are exposed to the sheltered environment of the Standby Shutdown Facility. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

5.2.2 Applicable Aging Effects

The materials of construction for components in this system are carbon steel, stainless steel, and glass. The applicable aging effects for components exposed to fuel oil is loss of material. The staff review of the aging effects of materials exposed to fuel oil is provided in Section 3.1.3.1.3 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that, pending acceptable resolution of Safety Evaluation Report Open Item 3.1.1-1, the Oconee Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The review to identify applicable aging effects for glass in fuel oil and air, and in a sheltered environment has not been previously reviewed by the staff. Duke has performed a review to identify the aging effects for glass using the methodology described in Section 3.5.2 of Exhibit A of the Application. Based on this review, Duke has determined that there are no applicable aging effects for glass exposed to either fuel oil or air/gas.

The exterior surfaces of the SSF Fuel Oil System are exposed to a sheltered environment. The applicable aging effects for carbon steel components exposed to a sheltered environment is loss

of material. No applicable aging effects exist for the stainless steel components exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

5.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the SSF Fuel Oil System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following programs will manage the aging effects of the SSF Fuel Oil System for the period of extended operation:

- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The above programs are described in the following paragraphs.

5.2.3.1 CHEMISTRY CONTROL PROGRAM

For loss of material in the components exposed to fuel oil, the Chemistry Control Program described in Section 4.6 of Exhibit A of the Application will manage the applicable aging effects for all components, including those added to the scope of license renewal. The staff review of the Chemistry Control Program is provided in Section 3.2.2 of the Safety Evaluation Report (June 1999). The SER does not contain the results of the staff review of the SSF Fuel Oil portion of the Chemistry Control Program.

5.2.3.2 INSPECTION PROGRAM FOR CIVIL ENGINEERING STRUCTURES AND COMPONENTS

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the Standby Shutdown Facility. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

Table 5

Aging Management Review Summary – SSF Fuel Oil System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Flexible Hose	Pressure Boundary	Stainless Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	None Identified	None Required
Pipe	Pressure Boundary	Carbon Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Pump Casing	Pressure Boundary	Carbon Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Sight Glass	Pressure Boundary	Glass	Fuel Oil	None Identified	None Required
			(SSF)	None Identified	None Required
Strainers	Pressure Boundary Filtration	Carbon Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	None Identified	None Required
Tubing	Pressure Boundary	Carbon Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	None Identified	None Required
Valve Bodies	Pressure Boundary	Carbon Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Fuel Oil	Loss of Material	Chemistry Control Program
			(SSF)	None Identified	None Required

6. Diesel Lube Oil System – Integrated Plant Assessment

6.1 Mechanical Components Subject to Aging Management Review

The Diesel Lube Oil System provides lubrication and cooling to the Standby Shutdown Facility (SSF) diesel engine bearings, gears, turbocharger bearings while the diesels are operating. The system also provides cooling of the diesel engine pistons while the diesels are in operation. While the diesel is in the standby mode, the lube oil circulating pumps circulate oil through the lube oil cooler to maintain lube oil temperature and to ensure pre-lubrication of the diesel engines. The portions of the Diesel Lube Oil System piping that are within the scope of license renewal are designed to the requirements of Oconee Piping Class C. Class C piping and components are designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction for components in this system are admiralty brass, carbon steel, stainless steel, and glass. The Diesel Lube Oil System components that are subject to aging management review are listed in Table 6.

6.2 Aging Management Review

6.2.1 Environments

The internal surfaces of the components of the Diesel Lube Oil System are exposed to oil or treated water environment. The potential aging effects for materials exposed to oil or treated water environments are discussed in Sections 3.5.2.3 and 3.5.2.2.5 of Exhibit A of the Application, respectively. The lube oil contains no moisture.

The external surfaces of components of the Diesel Lube Oil System are exposed to the sheltered environment of the Standby Shutdown Facility. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application. The external surfaces of the heat exchanger tubing and tube sheets are exposed to oil. The potential aging effects for materials exposed to oil environments are discussed in Sections 3.5.2.3 of Exhibit A of the Application.

6.2.2 Applicable Aging Effects

The materials of construction for components in this system are admiralty brass, carbon steel, stainless steel, and glass. The applicable aging effect for components constructed of admiralty brass and carbon steel exposed to treated water is loss of material. The staff review of the aging effects of materials exposed to treated water is provided in Section 3.1.3.1.5 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

Based on the review performed by Duke, there are no applicable aging effects for materials exposed to oil. The staff review of the aging effects of materials exposed to oil is provided in Section 3.1.3.1.3 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that, pending acceptable resolution of Safety Evaluation Report Open Item 3.1.1-1, the

Oconee Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The review to identify applicable aging effects for glass in oil and air environments has not been previously reviewed by the staff. Duke has performed a review to identify the aging effects for glass using the methodology described in Section 3.5.2 of Exhibit A of the Application. Based on this review, Duke has determined that there are no applicable aging effects for glass exposed to oil.

The exterior surfaces of the Diesel Lube Oil System are exposed to a sheltered environment. The applicable aging effects for carbon steel components exposed to a sheltered environment is loss of material. No applicable aging effects exist for the stainless steel components exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

6.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the Diesel Lube Oil System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following programs will manage the aging effects of the Diesel Lube Oil System for the period of extended operation:

- Chemistry Control Program
- Inspection Program for Civil Engineering Structures and Components

The above programs are described in the following paragraphs.

6.2.3.1 CHEMISTRY CONTROL PROGRAM

For loss of material in the components exposed to treated water, the Chemistry Control Program described in Section 4.6 of Exhibit A of the Application will manage the applicable aging effects for all components, including those added to the scope of license renewal. The staff review of the Chemistry Control Program is provided in Section 3.2.2 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that the applicant has demonstrated that these programs would adequately manage the aging effects associated with the system components in the Diesel Lube Oil System.

6.2.3.2 Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components exposed to the sheltered environment of the Standby Shutdown Facility. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

Table 6

Aging Management Review Summary – Diesel Lube Oil System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Filter	Pressure Boundary Filtration	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Felixible Hose	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Channel	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Shell	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Heat Exchanger Tubing	Pressure Boundary Heat Transfer	Admiralty Brass	Treated Water	Loss of Material	Chemistry Control Program
			(Oil)	None Identified	None Required
Heat Exchanger Tube Sheet	Pressure Boundary	Carbon Steel	Treated Water	Loss of Material	Chemistry Control Program
			(Oil)	None Identified	None Required
Orifice	Pressure Boundary Throttle	Stainless Steel	Oil	None Identified	None Required
			(SSF)	None Identified	None Required
Pipe	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Oil	None Identified	None Required
			(SSF)	None Identified	None Required
Pump Casing	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Sight Glass	Pressure Boundary	Glass	Oil	None Identified	None Required
			(SSF)	None Identified	None Required

Table 6
Aging Management Review Summary – Diesel Lube Oil System (continued)

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Strainers	Pressure Boundary Filtration	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Oil	None Identified	None Required
Tubing	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Oil	None Identified	None Required
			(SSF)	None Identified	None Required
Valve Bodies	Pressure Boundary	Carbon Steel	Oil	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Oil	None Identified	None Required
			(SSF)	None Identified	None Required

7. Starting Air System – Integrated Plant Assessment

7.1 Mechanical Components Subject to Aging Management Review

The Starting Air System provides dry compressed air to start the Standby Shutdown Facility (SSF) diesel engines. The portions of the Starting Air System piping that are within the scope of license renewal are designed to the requirements of Oconee Piping Class C. Class C piping and components are designed to remain operable during and following a seismic event (See Table 2.5-1 of Exhibit A of the Application). The materials of construction for components in this system are carbon steel, cast iron, monel (nickel-based alloy), and stainless steel. The Starting Air System components that are subject to aging management review are listed in Table 7.

7.2 Aging Management Review

7.2.1 Environments

The internal surfaces of the components of the Starting Air System are exposed to dry compressed air. The potential aging effects for materials exposed to compressed air are discussed in Section 3.5.2.1 of Exhibit A of the Application.

The external surfaces of components of the Starting Air System are exposed to the sheltered environment of the Standby Shutdown Facility. The potential aging effects for materials exposed to a sheltered environment are discussed in Section 3.5.2.7.2 of the Application.

7.2.2 Applicable Aging Effects

The materials of construction for components in this system are carbon steel, cast iron, monel (nickel-based alloy), and stainless steel. No applicable aging effects have been identified for these components exposed to a dry compressed air environment. The staff review of the aging effects of materials exposed to oil is provided in Section 3.1.3.1.1 of the Safety Evaluation Report (June 1999). Based on its review, the staff concluded that, pending acceptable resolution of Safety Evaluation Report Open Item 3.1.1-1, the Oconee Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

The exterior surfaces of the Starting Air System are exposed to a sheltered environment. The applicable aging effect for carbon steel or cast iron components exposed to a sheltered environment is loss of material. No applicable aging effects exist for the stainless steel or Monel components exposed to a sheltered environment. The staff review of the aging effects of materials exposed to a sheltered environment is provided in Section 3.1.3.1.7.2 of the Safety Evaluation Report. Based on its review, the staff concluded that the Application has included aging effects that are consistent with published literature and industry experience and that are acceptable to the staff.

7.2.3 Aging Management Programs

The applicable aging effects must be adequately managed so that the component intended functions will be maintained consistent with the current licensing basis for the period of extended operation. The applicable aging effects for the components of the Starting Air System will be managed by monitoring and controlling the aging effects directly or the relevant conditions that contribute to the onset and propagation of a specific aging effect. The following program will manage the aging effects of the Starting Air System for the period of extended operation:

- Inspection Program for Civil Engineering Structures and Components

The Inspection Program for Civil Engineering Structures and Components will manage loss of material on the exterior surfaces of the carbon steel components and cast iron exposed to the sheltered environment of the Standby Shutdown Facility. This program is described in Section 4.19 of Exhibit A of the Application. The staff review of the Inspection Program for Civil Engineering Structures and Components is provided in Section 3.2.6 of the Safety Evaluation Report. Based on its review, the staff concluded that the applicant has demonstrated that this program will adequately manage aging effects associated with civil engineering structures and components for the period of extended operation.

Table 7

Aging Management Review Summary – Starting Air System

Component Type	Component Function	Material	Environment Internal (External)	Aging Effects	Programs
Flexible Hose	Pressure Boundary	Stainless Steel	Air	None Identified	None Required
			(SSF)	None Identified	None Required
Lubricator	Pressure Boundary	Carbon Steel	Air	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Pipe	Pressure Boundary	Carbon Steel	Air	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
Strainers	Pressure Boundary Filtration	Cast Iron	Air	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Monel	Air	None Identified	None Required
Tubing	Pressure Boundary	Carbon Steel	Air	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Air	None Identified	None Required
			(SSF)	None Identified	None Required
Valve Bodies	Pressure Boundary	Carbon Steel	Air	None Identified	None Required
			(SSF)	Loss of Material	Inspection Program for Civil Engineering Structures and Components
		Stainless Steel	Air	None Identified	None Required
			(SSF)	None Identified	None Required

SER Open Item 2.2.3.6.1.2.1-1 – In Section 2.7.2, "Structural Components," of Exhibit A to the LRA, the applicant does not identify water stops, expansion joints, and structural sealants or caulking as structural components requiring an AMR. Section 2.7.3 of Exhibit A of the LRA states that all below grade construction joints in exterior walls are protected by cast-in-place water stops. The applicant stated (in response to RAI 2.7-3) that the water stops do not support any component intended functions and therefore are not subject to an AMR. The staff does not agree with the applicant's response because ground water in-leakage into the auxiliary building could occur as a result of degradation to the water stops. This leakage may cause flooding of equipment within the scope of license renewal and should be subject to an AMR (UFSAR Section 3.4.1, "Flood Protection," discusses the effects of flooding).

As discussed in Subsection 3.8.3.1 of this report, expansion joints are nonmetallic components that play important roles in maintaining the integrity of the components to which they are connected. Expansion joints perform their intended functions without moving parts or a change in configuration or properties, are not typically replaced based on a qualified life or specified time period, and therefore, should be subject to aging.

In addition, structural sealants or caulking are not addressed in Table 2.7-1or any other subsection under Section 2.7 of Exhibit A of the LRA. As discussed in Subsection 3.8.3.1 of this report, caulking is a nonmetallic component that plays important roles in maintaining the integrity of the components to which it is connected. These structural sealants perform their intended functions without moving parts or a change in configuration or properties, are not typically replaced based on a qualified life or specified time period. In addition, as stated in the staff's position regarding consumables (see License Renewal Issue No. 98-0012, "Consumables," dated April 20, 1999), structural sealants that are within the scope of license renewal typically meet the requirements under 10 CFR 54.21(a)(1)(i) and (a)(1)(ii). Structural sealants are often required for containment and structural integrity of safety-related structures, and perform these functions without moving parts or change in configuration or properties. These sealants are typically not replaced based on qualified life or specified time period, are often relied upon for decades of service, and are subject to aging. Therefore, structural sealants should be subject to an aging management review.

On the basis of the above evaluation, water stops, expansion joints, and structural sealants or caulking that are within the scope of license renewal, should be subject to an AMR.

Note: In addition to the above, the following discussion can be found in Section 3.8.3.1.8 of the SER.

In staff RAI 3.7.6-4, Duke was asked to discuss the basis for not including waterproofing membranes in Table 3.7-4 of the ONS LRA if they were used in the Keowee structures' exterior walls and base slabs to protect the concrete foundations or inhibit infiltration/seepage of ground water. The applicant was also asked to discuss ONS's approach to managing the effects of aging on the waterproofing membranes. Duke's response to the RAI stated that waterproofing membranes were not used in the Keowee structures to protect the concrete foundations or inhibit

infiltration/seepage of groundwater. Duke's response, however, did not indicate whether the Keowee structure or other inscope structures experienced any kind of seepage of groundwater or whether the groundwater leaching that might be anticipated at the construction joints was observed at the SSF during a recently performed scoping inspection at the ONS. Duke is requested to provide a list of the ONS inscope structures that had or are experiencing observable seepage or leaching by groundwater from aging degradation of sealants and caulking in concrete components, and is requested to discuss its approach for managing the aging effects. This information should be provided as part of Open Item 2.2.3.6.1.2.1-1.

Duke Response to SER Open Item 2.2.3.6.1.2.1-1
Duke does not define materials such as caulking, sealants, and waterstops to be structures or components. However, Duke recognizes that limited situations may exist where these materials are important in maintaining the integrity of the components to which they are connected.

The license renewal structure or component intended functions supported by these materials are limited to three functions. These functions are:

1. Maintaining pressure boundary. This function is limited to the Control Room.
2. Providing a rated fire barrier. Sealants and caulking that support this function are addressed as part of the fire barrier penetration seals in the Application. Fire barrier penetration seals are discussed in Sections 2.7.2.4 and 3.7.2.4 of Exhibit A of the Application. Aging of the fire barrier penetration seals is managed by the Oconee Fire Protection Program that is discussed in Section 4.16 of Exhibit A of the Application.
3. Providing a flood barrier. Caulking, sealants, and waterstops that support this function are limited to those contained in structures whose function is to provide a flood barrier. This function is identified as function #8 in the tables in Section 2.7 of Exhibit A of the Application. Specifically, the Auxiliary Buildings and the Standby Shutdown Facility are identified as providing internal/external flood barriers.

Caulking, sealants, and waterstops that support the flood barrier function are addressed below. Sealants associated with the Control Room pressure boundary are addressed in response to SER Open Item 2.2.3.4.3.2.1-2.

Reinforced concrete walls located below grade and flood curbs in the Auxiliary Buildings and the Standby Shutdown Facility provide a protective barrier for internal/external flood events. Caulking, sealants, and waterstops are important in maintaining the integrity of these walls and flood curbs. Caulking, sealants, and waterstops are used to seal joints in the walls and flood curbs. Degradation of the caulking, sealants, and waterstops may result in loss of the ability of the walls and flood curbs to provide a flood barrier. Gross degradation of these materials would be required to allow enough water to seep through the joint to produce flooding.

Degradation of the caulking, sealants, and waterstops in the Auxiliary Buildings and the Standby Shutdown Facility is managed by the Inspection Program for Civil Engineering Structures and Components. The program is discussed in Section 4.19 of Exhibit A of the Application. The

program visually inspects concrete for evidence of degradation of the caulking, sealants, and waterstops. Evidence of degradation may include but is not limited to water in-leakage, leaching, peeling paint, or discoloration of the concrete. Inspection findings are evaluated to determine the appropriate corrective action that may include monitoring or repair/replacement of the caulking or sealant.

Oconee operating experience has identified instances where degradation of these materials has resulted in discoloration of the concrete and leaching in the Keowee Powerhouse, the Auxiliary Buildings, and Standby Shutdown Facility. While Keowee concrete structures do not provide a flood barrier and water seepage is a normal occurrence in dam facilities, evidence of leaching and discoloration of concrete has been detected and corrective actions have been taken. For the Auxiliary Buildings and Standby Shutdown Facility, caulking and sealants have been repaired/replaced. Where discoloration and leaching have been identified along joints with waterstops, the joint has been sealed on the inside surface of the concrete. Continued implementation of the Inspection Program for Civil Engineering Structures and Components provides reasonable assurance that caulking, sealants, and waterstops will be maintained to support the intended functions of the Auxiliary Buildings and Standby Shutdown Facility in accordance with the CLB for the period of extended operation.

Note: On page 3-217 of the SER, the staff indicates that SER Open Item 2.2.3.6.1.2.1-1 also applies to the Intake Structure. In our response to RAI 3.7.5-2 provided by letter dated February 17, 1999, Duke indicated that the inspection of the Intake Structure, including caulking and sealants, is performed in accordance with the Inspection Program for Civil Engineering Structures and Components.

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

Note: This above open item is repeated for the turbine building roof in Section 2.2.3.6.7.2.1 of this SER.

Duke Response to SER Open Item 2.2.3.6.4.2.1-1
Rather than generically excluding the roofs based on performance or condition monitoring, Duke has reevaluated whether the roofs are subject to aging management review based on function. Upon further investigation, Duke has determined that the roof systems for the Keowee Powerhouse and the Oconee Turbine Buildings are not subject to aging management review because they do not perform a §54.4 intended function. The Keowee Powerhouse and Oconee Turbine Building are within the scope of license renewal in accordance with the criteria in §54.4. Certain structural components of these two structures perform a structural intended function as identified in Tables 2.7-4 and 2.7-7 of Exhibit A of the Application. The roofs are components of the Powerhouse and Turbine Building, but the roofs do not perform an intended function. Degradation or loss of either the Keowee Powerhouse or Turbine Building roof will not result in loss of any structural, mechanical or electrical system or component intended function.

If the Keowee Powerhouse roof were to degrade, equipment located on the operating floor would remain sheltered/protected. Table 2.7-4 of Exhibit A of the Application identifies those components that perform the intended function of shelter/protection of safety-related equipment. The breakers are protected by a reinforced concrete breaker vault. The breaker vault is constructed of reinforced concrete walls, floor slab and roof slab. Electrical equipment is protected by the switchgear cabinets. Switchgear cabinets are included with electrical panels and enclosures. The turbine generator is protected with a metal cover. Therefore, degradation of the Powerhouse roof would not result in the loss of any component intended function.

The Turbine Building contains safety-related equipment located in the basement. If the Turbine Building roof were to degrade, equipment located in the basement would remain

sheltered/protected. The equipment is located beneath several reinforced concrete floors. These floors provide shelter/protection to the equipment located beneath them (See Table 2.7-7 of Exhibit A of the Application for identification of the Turbine Building components which provide shelter/protection). Therefore, degradation of the Turbine Building roof would not result in the loss of any component intended function.

In summary, the Keowee Powerhouse roof and the Turbine Building roof do not perform an intended function within the scope of license renewal. Degradation of these components has been evaluated and it has been determined that degradation would not result in the loss of any system, structure, or component intended function. Therefore, aging management review of the Keowee Powerhouse and Turbine Building roofs is not required.

The requirements of §54.21(a)(1) are to list and identify within the application those structures and components subject to aging management review. Since the roofs are not subject to aging management review, the roofs are not listed in Tables 2.7-4 and 2.7-7 of Exhibit A of the Application.

SER Open Item 2.2.3.7-1 – In Section 2.6.6.1.2 of the application, the applicant identified insulated cables and connections used for fire detectors as part of the fire detection system and excluded them from an AMR because they are replaced based on a performance or condition program. In response to RAI 2.6-4, the applicant referenced SOC Section III.f.(I)(b) and 10 CFR 54.21 (a)(1)(ii) as the basis for excluding fire detector cables and connections from an AMR. However, the applicant also stated that the fire detector cables are not physically different from other insulated cables. There is no generic exclusion for components that are replaced based on performance or condition. An applicant may exclude from an AMR components or structures that are replaced on the basis of specific performance and condition monitoring activities if the following two conditions are met: 1) that the applicant identifies those structures and components in the LRA that are being excluded based on performance and condition monitoring, and 2) that the applicant submit a site-specific justification for the exclusion of these components. The applicant should either provide a plant-specific justification for excluding these components from an AMR or include them in an AMR.

Duke Response to SER Open Item 2.2.3.7-1
Duke agrees with the staff position regarding the Oconee fire detector cables. Following discussion with staff during the on-site inspections, Duke now understands that detection of degradation is a necessary aspect of excluding a component based on performance or condition. The fire detector cables as part of the fire detection system are provided with failure detection, not detection of degradation. Therefore, Duke has now included the fire detector cables in the aging management review of insulated cables and connections. The results of the aging management review for fire detector cables are summarized below.

The fire detector cables are constructed of XLPE insulation and are low-voltage. Section 3.6.3 of Exhibit A of the Application provides the aging management review for insulated cables and connections with the review for applicable aging effects starting in Section 3.6.3.1 of Exhibit A of the Application. Moisture, heat and radiation potentially result in cable aging. Section 3.6.3.1.1 of Exhibit A of the Application reviews low-voltage connectors exposed to moisture and the addition of fire detector cables does not change the conclusions of that section.

Section 3.6.3.1.2 of Exhibit A of the Application (replaced via Response to RAI 2.6-1 provided by Duke letter dated February 17, 1999) reviews medium-voltage cables exposed to moisture. Since the fire detectors are part of a low-voltage system (< 2kV), this aging effect is not applicable to fire detector cables.

Sections 3.6.3.1.3 and 3.6.3.1.4 of Exhibit A of the Application provides the results of the reviews of low and medium-voltage cables exposed to radiation and heat respectively. As indicated in Table 3.6-3 of Exhibit A of the Application (replaced via Response to RAI 2.6-1), XLPE insulation material is already included in the review of all areas. Comparing the radiation and temperature values given in Tables 3.6-5 and 3.6-6 of Exhibit A of the Application with the service conditions shown in Table 3.6-3 of Exhibit A of the Application (replaced via Response to RAI 2.6-1 provided by Duke letter dated February 17, 1999), indicates that XLPE insulation material can withstand the maximum 60-year normal radiation dose and heat. Therefore,

radiation and heat will not cause fire detector cables to age to the point of loss of intended function.

Based on this review, the conclusion of the aging management review in Section 3.6 of Exhibit A of the Application has not changed due to the addition of the fire detector cables.

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

Duke Response to SER Open Item 2.2.3.7-2
The Appendix R equipment stored in the warehouse (motors, switchgear) are routinely inspected, tested and maintained. Since the Appendix R motor and switchgear are treated similarly to the motors and switchgears installed in the plant, they are appropriately considered active and are not subject to an aging management review.

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

Duke Response to SER Open Item 3.0-1
Duke agrees that the resolution of the information that needs to be added to the UFSAR will be addressed after the other open and confirmatory items are resolved and prior to the issuance of the renewed operating licenses for Oconee.

SER Open Item 3.1.1-1 – The staff found the applicant included appropriate aging effects that are consistent with published literature and industry experience and thus, are acceptable to the staff. The staff reviewed the applicant's assessment of aging effects in Sections 3.5.3 through 3.5.14 of the LRA, as summarized in Table 3.5 of the LRA. The staff found unexplained discrepancies between the discussion of applicable aging effects found in Section 3.5.2 of the LRA and the assessment of these aging effects in Sections 3.5.3 through 3.5.14, and the summary of aging effects found in Table 3-5 of the LRA. The specific discrepancies are detailed in Section 3.1 of the safety evaluation report in the discussion of aging effects associated with an air environment, an oil environment, a raw water environment, a treated water environment, and a ventilation air environment. The staff requests the applicant provide additional information to support its assessment of aging effects in Section 3.5.3 through 3.5.14, such that they are consistent with the discussion in Section 3.5.2 of the LRA.

Duke Response to Open Item 3.1.1-1
Section 3.5.2 of the Application lists the applicable aging effects for the materials exposed to the different environments found at Oconee. An applicable aging effect for a material in a particular environment may not occur in all systems with that material/environment combination due to specific system parameters. For example, loss of material due to general corrosion of carbon steel exposed to air is identified as an applicable aging effect. For general corrosion to occur, oxygen <u>and</u> moisture must be present. In the carbon steel Instrument Air System, the air in contact with the carbon steel has been processed through a dryer to remove the moisture. Since the moisture has been removed, general corrosion of the carbon steel will not occur. Therefore, loss of material due to general corrosion of the carbon steel is not an applicable aging effect even though Section 3.5.2 would lead one to conclude it should be an applicable aging effect in the Instrument Air System.

The specific discrepancies detailed in Section 3.1 of the safety evaluation report associated with an air environment, an oil environment, a raw water environment, a treated water environment, and a ventilation air environment are presented and addressed below.

Air/Gas Environment SER Open Items

Containment Isolation Systems
In Section 3.5.4 and Table 3.5-2 of the LRA, the applicant stated no applicable aging effects for the carbon steel components exposed to air in the instrument air system, the leak rate test system and the reactor building purge system.

HVAC Systems
In Section 3.5.8 and Table 3.5-6 of the LRA, the applicant stated no applicable aging effects for the carbon steel components exposed to air in the penetration room ventilation system.

RCP Motor Oil Collection System
In Section 3.5.11 and Table 3.5-9 of the LRA, the applicant stated no applicable aging effects for the carbon steel components exposed to air in the RCP motor oil collection system.

Keowee Hydroelectric Station
In Section 3.5.13 and Table 3.5-11 of the LRA, the applicant identified no applicable aging effects for the carbon steel pipe and tank in the Keowee governor oil system and the carbon steel pipe and tank in the Keowee turbine guide bearing oil systems.

Standby Shutdown Facility
In Section 3.5.14 and Table 3.5-12 of the LRA, the applicant identified no aging effects for the carbon steel tank in the SSF diesel generator fuel oil system, the cast iron pump casing in the SSF auxiliary service water system, and the carbon steel components in the SSF starting air system.

DUKE RESPONSE TO AIR/GAS ENVIRONMENT SER OPEN ITEMS

Containment Isolation Systems
The Instrument Air System provides clean, dry, oil-free compressed air to plant components. This environment does not contain the moisture and halides that could be present in unconditioned air necessary for loss of material of carbon steel and stainless steel to be an applicable aging effect. Therefore, no applicable aging effects were identified for the Instrument Air System.

The Leak Rate Test System is used to perform periodic integrated leak rate tests of the Reactor Building containment for pressure boundary integrity. During testing, this system routes clean, dry, oil-free compressed air to the Reactor Building. During normal unit operation, this system is isolated and stagnant. This environment does not contain the moisture and halides that could be present in unconditioned air necessary for loss of material of carbon steel and stainless steel to be an applicable aging effect. Therefore, no applicable aging effects were identified for the Leak Rate Test System.

The Reactor Building Purge System is a ventilation system. The applicable aging effects for this system are found in Section 3.5.2.6 of the Application, not Section 3.5.2.1. The Reactor Building Purge System purges the Reactor Building with fresh air during and just prior to unit outages or acts as a recirculation clean-up to reduce contaminant levels inside the Reactor Building. This system is normally in standby. From Section 3.5.2.6 of the Application, loss of material due to galvanic corrosion or boric acid wastage is the applicable aging effect if either water or boric acid is present. Neither of these is present in this normally standby system. Therefore, the Reactor Building Purge System has no applicable aging effects.

HVAC Systems
The Penetration Room Ventilation System is a ventilation system. The applicable aging effects for this system are found in Section 3.5.2.6 of the Application, not Section 3.5.2.1. From Section 3.5.2.6 of the Application, loss of material due to galvanic corrosion or boric acid wastage is an applicable aging effect in the presence of either water or boric acid. This system is normally in

standby and neither of these environments is present. Therefore, the Penetration Room Ventilation System has no applicable aging effects.

RCP Motor Oil Collection System
Each outage the reactor coolant pump (RCP) motor oil pots are drained into the RCP Motor Oil Collection System. The RCP Motor Oil Collection System tanks are then drained. As noted in Section 3.5.2.1, loss of material is a concern in the presence of moisture and concentrated halides. Since the RCP Motor Oil Collection System is used to drain the oil from the motors, the internal surfaces would be covered with an oil film that would prevent the water and halides that could be present in unconditioned air from contacting the material surface. Therefore, no applicable aging effects were identified for the components exposed to air in the RCP Motor Oil Collection System.

Keowee Hydroelectric Station
The carbon steel pipe and tank found in the Governor Oil System exposed to air are coated with an oil film that would prevent the moisture and halides that could be present in unconditioned air from contacting the material surface. Therefore, no applicable aging effects were identified for the components exposed to air in the Governor Oil System.

Likewise, the carbon steel pipe and tank found in the Turbine Guide Bearing Oil System exposed to air are coated with an oil film that would prevent the moisture and halides that could be present in unconditioned air from contacting the material surface. Therefore, no applicable aging effects were identified for the components exposed to air in the Turbine Guide Bearing Oil System.

Standby Shutdown Facility
The portion of the carbon steel tank found in the Standby Shutdown Facility (SSF) Diesel Generator Fuel Oil System exposed to air is coated with a fuel oil film that would prevent the moisture and halides that could be present in unconditioned air from contacting the material surface. Therefore, no applicable aging effects were identified for the components exposed to air in the SSF Diesel Generator Fuel Oil System.

The cast iron pump casing noted in Section 3.5.14 and Table 3.5-12 is the SSF Submersible Pump. As noted in Section 3.5.14.7.1 the SSF Submersible Pump is not a permanently installed piece of equipment. The SSF Submersible Pump is stored in the SSF and exposed internally and externally to the ambient air within the Standby Shutdown Facility. Every two years the submersible pump is placed in the intake canal (Lake Keowee) for testing and then returned to the SSF for storage. Since exposure to raw water is infrequent, the ambient air of the SSF is the environment for identifying the applicable aging effects for the internal and external surfaces of the submersible pump. No applicable aging effects were identified for the cast iron pump exposed to the ambient air of the SSF that could result in a loss of the component intended function of the submersible pump. Since the SSF ambient air is the environment to which the SSF Submersible Pump is exposed, Table 3.5-12 should not contain the entry of the cast iron pump casing exposed to raw water.

The SSF Starting Air System provides compressed air for starting the diesel engines located in the SSF. The air is stored in receiver tanks. Before the air is stored in the receiver tanks, it is passed through an aftercooler, moisture separator, filter, desiccant dryer, and another filter. For the applicable aging effects listed in Section 3.5.2.1 to occur, moisture or halide ions must be present. The moisture has been removed. The suction source for this system is the ambient air found in the SSF. The ambient air does not contain halide ions in sufficient concentrations to be a concern. Therefore, no applicable aging effects were identified for the carbon steel components in the SSF Starting Air System.

Oil Environment SER Open Items

RCP Motor Oil Collection System

In Section 3.5.11 and Table 3.5-9 of the LRA, the applicant did not include cracking as an applicable aging effect for the stainless steel valve bodies and tubing exposed to an oil environment.

Keowee Hydroelectric Station

In Section 3.5.13 and Table 3.5-11, the applicant identified no aging effects for any components in the Keowee generator high pressure oil system and the Keowee turbine guide bearing oil system exposed to an oil environment. The applicant did not include cracking as an applicable aging effect for the stainless steel valve bodies and tubing in the Keowee governor oil system exposed to an oil environment.

Duke Response to Oil Environment SER Open Items

RCP Motor Oil Collection System

Section 3.5.2.3 of the Application identifies cracking of stainless steel components exposed to fuel oil, not lubricating oil, in the presence of oxygenated water as an applicable aging effect. Lubricating oil contains corrosion inhibitors, emulsifying agents, and has overall coating properties that will not result in the conditions necessary for the propagation of cracking of stainless steel components. Each outage the reactor coolant pump (RCP) motor oil pots are drained into the RCP Motor Oil Collection System. The RCP Motor Oil Collection System tanks are then drained. Since the RCP Motor Oil Collection System is used to drain the oil from the motors, the internal surfaces would be covered with an oil film. Since this system is exposed to lubricating oil and not fuel oil, cracking was not identified as an applicable aging effect for the stainless steel components in the RCP Motor Oil Collection System.

Keowee Hydroelectric Station

Section 3.5.2.3 identifies the applicable aging effects for materials exposed to an oil environment. For these aging effects to occur in a lubricating oil environment, oxygenated water must be present. Loss of material due to microbiologically influenced corrosion and cracking due to stress corrosion are applicable to fuel oil only. The Generator High Pressure Oil System is located at Keowee and is a closed system filled with lubricating oil. Water contamination of this

system is not likely. Therefore, no applicable aging effects were identified for the components in the Generator High Pressure Oil System.

Section 3.5.2.3 identifies the applicable aging effects for materials exposed to an oil environment. For these aging effects to occur in a lubricating oil environment, oxygenated water must be present. Loss of material due to microbiologically influenced corrosion and cracking due to stress corrosion are applicable to fuel oil only. The Turbine Guide Bearing Oil System is recirculated continuously which would prevent water from pooling to create a corrosive environment. Due to the continuous recirculation, a corrosive environment will not exist in this system. Therefore, no applicable aging effects were identified for the components in the Turbine Guide Bearing Oil System.

Section 3.5.2.3 of the Application identifies cracking of stainless steel components exposed to fuel oil, not lubricating oil, in the presence of oxygenated water as an applicable aging effect. Lubricating oil contains corrosion inhibitors, emulsifying agents, and has overall coating properties that are not likely to result in the conditions necessary for the propagation of cracking of stainless steel components. The Governor Oil System uses lubricating oil. Since this system is exposed to lubricating oil and not fuel oil, cracking was not identified as an applicable aging effect for the stainless steel components in the Governor Oil System.

Raw Water Environment SER Open Items

Auxiliary Systems

In Section 3.5.6 and Table 3.5-4 of the LRA, the applicant identifies no applicable aging effects for the cast iron pump casing, recirculating cooling water heat exchangers, and screens of the condenser circulating water system and tubing of the high pressure service water system. Also, the applicant does not identify fouling as an applicable aging effect for valve bodies in the condenser circulating water system, a cast iron pump casing in the high pressure service water system, and for the component coolers of the low pressure service water system.

Keowee Hydroelectric Station

In Section 3.5.13 and Table 3.5-11, the applicant identified no aging effects for the brass, carbon steel, copper and stainless steel tubing exposed to raw water in the Keowee service water system. Also, fouling is not identified as an applicable aging effect for the cast iron pump casing in the Keowee service water system and the stainless steel heat exchanger shell, tubes, and tubesheet in the Keowee turbine guide bearing oil system exposed to raw water.

Standby Shutdown Facility

In Section 3.5.14 and Table 3.5-12, the applicant did not identify any aging effects for the cast iron pump casing in the SSF auxiliary service water system. Also, in Table 3.5-12, the applicant did not identify fouling as an applicable aging effect for the carbon steel and cast iron pump casings in the SSF auxiliary service water system.

Duke Response to Raw Water Environment SER Open Items

Auxiliary Systems

The cast iron pump casing, recirculating cooling water heat exchangers, and screens of the condenser circulating water system and tubing of the high pressure service water system components have no component intended functions that are required in support of the system intended functions. Since the components have no component intended functions in support of the system intended functions, identification of the applicable aging effects is not required and the aging management review is complete. The explanation for each component in question will be handled separately.

Cast Iron Pump Casing: This pump is the Turbine Driven Emergency Feedwater Pump Oil Cooler Pump. The pump does form a part of the Condenser Circulating Water System pressure boundary. However, failure of the pump casing will not fail the Condenser Circulating Water System intended functions. Therefore, pressure boundary is not a required function of this pump. As a result, identification of the applicable aging effects is not required and the aging management review for this component is complete.

Recirculating Cooling Water Heat Exchanger: Heat transfer is not a required function of these heat exchangers. The heat exchangers do form part of the Condenser Circulating Water pressure boundary. However, the Recirculating Cooling Water System operates at a higher pressure than the Condenser Circulating Water System. If a tube were to leak, water from the Recirculating Cooling Water System would leak into the Condenser Circulating Water System. The pressure boundary function is therefore not required for these coolers. As a result, identification of the applicable aging effects is not required and the aging management review for this component is complete.

Screens: The screens in the Condenser Circulating Water System are collector screens that remove condenser tube cleaning balls from the Condenser Circulating Water System flowpath after the balls travel through the condenser tubes. They are in-line components and have no pressure retaining parts. Also, the filtration function of the collection screens is not required to support the system intended functions. Therefore, since they perform no component intended function, the identification of the applicable aging effects for the collection screens in this system is not required and the aging management review is complete.

Valve Bodies: Fouling of valve bodies in Condenser Circulating Water System could prevent flow from being successfully provided and thus prevent the system from performing its intended function. However, the valves in this system are located in large bore piping that is normally in service. Fouling of large bore valve bodies to the extent that system function will be lost is considered unlikely. Therefore, fouling of valve bodies is not an applicable aging effect.

Tubing: No instruments with associated tubing in the High Pressure Service Water System are required to function in support of any system intended function. Additionally, if pressure boundary integrity of this small diameter tubing were lost, the High Pressure Service Water

System intended functions would not be lost. Therefore, since pressure boundary is not required of these components, the identification of applicable aging effects is complete and the aging management review for tubing in the High Pressure Service Water System is complete.

Cast Iron Pump Casing: Periodic operation of the pumps in the High Pressure Service Water System, fouling of the cast iron pump casings in the High Pressure Service Water System is not considered likely. Therefore, fouling of the cast iron pump casings in the High Pressure Service Water System is not an applicable aging effect.

Component Coolers: Heat transfer is not a required function of these coolers. The coolers do form a part of the Low Pressure Service Water System pressure boundary and are required to maintain pressure boundary. Fouling of the Component Coolers does not affect the pressure boundary function of the coolers or the Low Pressure Service Water System. Therefore, fouling of the Component Coolers is not an applicable aging effect.

Keowee Hydroelectric Station
The Section of Table 3.5-11 of Exhibit A of the Application in question is related to the Keowee Service Water System. Tubing should not have been included in this system at all. No tubing exists in the Keowee Service Water System as noted in response to Potential Open Item 4.25-4 by letter dated May 10, 1999.

Due to normal operation of the cast iron pump in the Keowee Service Water System, fouling of the pump casing is not considered likely. Therefore, fouling of the cast iron pump casing is not an applicable aging effect for the pump casing in the Keowee Service Water System.

The intended function of the Turbine Guide Bearing Oil Cooler is pressure boundary for the Turbine Guide Bearing Oil System. Heat transfer is not a function within the scope of license renewal. Fouling of the raw water side of the heat exchanger does not affect the intended function of maintaining pressure boundary for the Turbine Guide Bearing Oil System. Therefore, fouling is not an applicable aging effect for the Turbine Guide Bearing Oil Coolers.

Standby Shutdown Facility
The cast iron pump casing noted in Section 3.5.14 and Table 3.5-12 is the Standby Shutdown Facility (SSF) Submersible Pump. As noted in Section 3.5.14.7.1 the SSF Submersible Pump is not a permanently installed piece of equipment. The SSF Submersible Pump is stored in the SSF and exposed internally and externally to the ambient air within the Standby Shutdown Facility. Every two years the submersible pump is placed in the intake canal (Lake Keowee) for testing and then returned to the SSF for storage. Since exposure to raw water is infrequent, the ambient air of the SSF is the environment for identifying the applicable aging effects for the internal and external surfaces of the submersible pump. No applicable aging effects were identified for the cast iron pump expose to the ambient air of the SSF that could result in a loss of the component intended function of the submersible pump. Since the SSF ambient air is the environment to which the SSF Submersible Pump is exposed, Table 3.5-12 should have not contain the entry of the cast iron pump casing exposed to raw water.

The cast iron SSF Submersible Pump is stored in the SSF. Fouling of the cast iron pump casing is not possible. Therefore, fouling of the SSF Submersible Pump is not an applicable aging effect.

The carbon steel pump casing is the SSF Auxiliary Service Water Pump. Due to periodic operation, fouling of the pump casing is not considered likely. Therefore, fouling of these pumps casing is not an applicable aging effect.

TREATED WATER ENVIRONMENT SER OPEN ITEMS

Emergency Core Cooling System
In Section 3.5.5 and Table 3.5-3 of the LRA, the applicant did not identify any aging effects for the carbon steel heat exchanger shell exposed to treated water.

Auxiliary Systems
In Section 3.5.6 and Table 3.5-4 of the LRA, the applicant identified no applicable aging effects for the carbon steel and brass recirculating cooling water heat exchangers of the condenser circulating water system exposed to a treated water environment.

DUKE RESPONSE TO TREATED WATER ENVIRONMENT SER OPEN ITEMS

Emergency Core Cooling System
The Reactor Coolant Pump Seal Return Coolers are required to maintain their pressure boundary in support of the High Pressure Injection System intended functions. These coolers do not perform any function in support of the Recirculating Cooling Water System. Loss of material of the carbon steel channel heads exposed to treated water will not affect the pressure boundary function of the coolers needed in support of the High Pressure Injection System functions. Therefore, no aging management program to manage the aging of the channel heads is required. Also, in Table 3.5-3 the term "HX Shell" constructed of carbon steel could more accurately read as "HX Channel Heads."

Auxiliary Systems
The section of Table 3.5-4 of Exhibit A of the Application in question is related to the Condenser Circulating Water System. The statement that there are no aging effects is somewhat misleading. Actually, the component in question has no component intended function and therefore does not require identification of aging effects nor an aging management review. For the Recirculating Cooling Water Heat Exchanger, heat transfer is not a required function of these heat exchangers. The heat exchangers do form part of the Condenser Circulating Water pressure boundary. However, the Recirculating Cooling Water System operates at a higher pressure than the Condenser Circulating Water System. If a tube were to leak, water from the Recirculating Cooling Water System would leak into the Condenser Circulating Water System. The pressure boundary function is therefore not required for these coolers. If left unmanaged, loss of material in the Recirculating Cooling Water Heat Exchangers will not result in a loss of the Condenser Circulating Water System pressure boundary.

VENTILATION AIR ENVIRONMENT SER OPEN ITEM

In Section 3.5.8 and Table 3.5-6 of the LRA, the applicant identified no applicable aging effects for the aluminum, galvanized steel, brass, carbon steel, and copper components of the control room pressurization and filtration system exposed to a ventilation air environment.

DUKE RESPONSE TO VENTILATION AIR ENVIRONMENT SER OPEN ITEM

From Section 3.5.2.6 of the Application, loss of material due to galvanic corrosion or boric acid wastage is an applicable aging effect in the presence of either water or boric acid. The Control Room Pressurization and Filtration System contains a wetted environment in the air handling units. The air handling units are constructed of either aluminum, galvanized steel, or stainless steel that would preclude the presence of a galvanic couple. No boric acid is present in the control room to be drawn into the system. Therefore, no applicable aging effects were identified for the Control Room Pressurization and Filtration System.

SER Open Item 3.1.3.1.7.4-1 – The NRC staff concurs with the applicant's conclusion that these aging effects are applicable for the materials exposed to an underground environment because up-to-date industry and ONS-specific experience substantiate this conclusion. However, the staff could not identify all buried piping based on information in this application. The applicant is requested to identify all buried piping that are subject to an aging management review, their material of construction, and their aging management program.

Duke Response to Open Item 3.1.3.1.7.4-1
From Section 3.5.2.7.4 of the Exhibit A of the Application, the following systems within the scope of license renewal contain components that are buried:

- Condenser Circulating Water System
- High Pressure Service Water System
- Service Water System (Keowee)
- Standby Shutdown Facility Diesel Generator Fuel Oil System
- Turbine Generator Cooling Water System (Keowee)

The materials of construction of the components that are buried are carbon steel, cast iron, and stainless steel. One or more of these materials may appear in each of the systems listed above.

The portions of the system that are buried are identified on the Oconee License Renewal flow diagrams. The flow diagrams for each of these systems are identified in Tables 2.5-2 through 2.5-25 of Exhibit A of the Application. The buried portions of the systems are identified by finding lines that bisect the flowpath with arrows pointing toward the buried components. The lines with arrows that bisect the flowpath contain the two-letter designation "UG" for underground.

Aging of all the buried components in the system identified earlier is managed by the Condenser Circulating Water System Internal Coatings Inspection and the Standby Shutdown Facility Diesel Fuel Oil Tank Inspection of the Preventive Maintenance Activities. The preventive maintenance activities were described in detail in the response to RAI 4.3.8-1.

SER Open Item 3.2.3.3-1 – Based on the review of the applicant's revised response to RAI G-1 and RAI 4.13-1, contained in its May 10, 1999 letter, the staff has determined that this approach is acceptable. However, the applicant needs to include a specific commitment relative to the application of 10 CFR Part 50, Appendix B corrective action requirements to all ONS structures and components subject to AMR in either Appendix B, "UFSAR Supplement" of the application, or in Duke Energy Corporation Topical Report "Quality Assurance Program," DUKE-1A.

Therefore, pending the applicant's formal commitment to apply 10 CFR Part 50, Appendix B corrective action requirements to non-safety-related structures and components that are subject to an AMR program, this issue is identified as SER Open Item

Duke Response to SER Open Item 3.2.3.3-1
To address this open item, Duke proposes to revise the UFSAR Supplement corrective action statement of each credited aging management program that contains non-safety-related structures and components within its scope rather than revising the Duke QA Topical Report, Duke – 1A.

The plant program that implements the corrective action requirements of 10 CFR 50, Appendix B is the Problem Investigation Process (PIP). PIP has been described in the responses to staff requests for additional information (RAI) 4.3.9-3 and 4.3.9-4 (Duke letter dated December 14, 1998, Attachment 1, page 39). Additional information on PIP is contained in M. S. Tuckman (Duke) letter dated February 10, 1997 to Document Control Desk (NRC), "Adequacy and Availability of Design Basis Information."

For each applicable credited aging management program, the corrective action statement will be revised to state that the Problem Investigation Process applies to all structures and components within the scope of the specific program. As an example, the following would be the revised corrective action statement of the *Tendon - Secondary Shield Wall - Surveillance Program* [underlined portion denotes revised text]:

Corrective Action - Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by replacement. <u>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 *Tendon - Secondary Shield Wall - Surveillance Program.*</u>

The above commitment will be implemented concurrent with the UFSAR update required by 10 CFR 50.71(e) after the Oconee renewed operating license is issued by the NRC.

SER Open Item 3.2.12-1 – During the tests for the LPI decay coolers and the reactor building cooling units, the applicant measures flow rates and temperatures differences across the heat exchangers. The staff finds these parameters acceptable because they are considered standard for this type of application and proven effective for detecting reduction of cooling capacity caused by fouling and/or loss of material. For the SSF HVAC coolers, the applicant measures flow rate of the raw water through the condensers. The staff requests that the applicant provide additional information to justify why temperature difference across the SSF HVAC coolers is not measured. This is a concern because one of the aging affects identified by the applicant is loss of material of the aluminum fins of the cooling coils. If these fins were broken, then cooling capacity would be degraded, but the flow rate through the condenser tubes would remain the same. Thus, the staff concludes that measuring only flow rate is not enough to verify that the cooling units are maintaining their heat transfer capacity in accordance with their intended function.

Duke Response to SER Open Item 3.2.12-1
The components under question are the Standby Shutdown Facility (SSF) HVAC Coolers. The SSF HVAC Coolers are three coolers connected with a refrigerant loop that comprise a refrigeration unit. Two of the three coolers are the water-cooled SSF HVAC condensers discussed in Section 3.5.14.7 of Exhibit A of the Application. The applicable aging effects for the portions of the coolers exposed to raw water are fouling and loss of material of the raw water side of the coolers. Fouling of the raw water side of the coolers is managed by the Heat Exchanger Performance Testing Activities presented in Section 4.17 of Exhibit A of the Application. The staff is correct that the application is incomplete in that all the applicable aging effects are not managed by this raw water flow measurement. Loss of material of the raw water portion of the coolers is managed by measuring the collection of parameters associated with the refrigeration unit. These parameters include inlet and outlet temperatures of all three coolers as well as refrigerant conditions. The activity that assesses these parameters is discussed below.

The third cooler is the air cooling coil discussed in Section 3.5.14.4 of the Application. The applicable aging effect for the air side of the air cooling coil is loss of material of the air cooling coil fins. Loss of material here is managed by visual inspection of the aluminum fins for signs of material loss. Management of both the raw water side and air side loss of material is accomplished by the SSF HVAC Coolers Preventive Maintenance Activity. The SSF HVAC Coolers Preventive Maintenance Activity is described below using the program attributes described in Section 4.2 of Exhibit A of the Application.

STANDBY SHUTDOWN FACILITY HVAC COOLERS PREVENTIVE MAINTENANCE ACTIVITY

Purpose – The purpose of the Standby Shutdown Facility (SSF) Air Handling Unit Preventive Maintenance Activity is to manage loss of material in the SSF HVAC Coolers.

Scope – The water-side of the two water-cooled SSF HVAC condensers and the external surface of the air cooling coil are addressed by this activity.

Aging Effects – Loss of Material

Method – For the water-cooled SSF HVAC condensers, heat transfer parameters of the entire refrigeration unit are monitored to provide evidence of loss of material. Parameters monitored include inlet and outlet temperatures of all three coolers as well as refrigerant conditions. The aluminum fins on the air cooling coils are visually inspected for loss of material.

Sample Size – Not applicable for an existing activity.

Industry Codes and Standards – No code or standard exists to guide or govern this examination.

Frequency – This activity is performed semi-annually.

Acceptance Criteria – 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, no indications of loss of material of the aluminum fins.

Corrective Action – 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.

Timing of New Program Initiation – The SSF HVAC Coolers Preventive Maintenance Activity is an existing maintenance activity that will be continued into the extended period of operation.

Administrative Control – The maintenance activity is implemented by a controlled plant procedure.

Regulatory Basis – The examination is implemented in response to Oconee Technical Specification 3.10.1d, SSF Power System. (See Improved Technical Specification Bases page B.3.10.1-3)

SER Open Item 3.2.12-2 – For the decay heat removal coolers and the reactor building cooling units, the applicant determines heat removal capacity (based on flow rates and temperature difference) and compares the test results to the acceptance criteria. For the SSF heat exchangers, the applicant verifies acceptable cooling-water flow rates through these heat exchangers. The staff requests the applicant to state specifically what the acceptance criteria are for each of these heat exchangers and provide the basis for the acceptance criteria. The applicant should discuss in its response how the acceptance limits ensure sufficient heat transfer capacity under both normal operating and accident conditions. Also, for the decay heat coolers, the applicant implements corrective actions if the heat transfer capacity degrades more than 4% from the last test. The staff requests the applicant to state if similar criteria are in place for the reactor building cooling units and the SSF heat exchangers. If not, the applicant should discuss why this is not needed. The applicant should also discuss in its response the basis for implementing corrective actions upon measuring a 4% degradation in heat transfer capacity. The insufficient specificity on the acceptance limits and corrective actions for the heat exchangers are identified as an Open Item.

Duke Response to SER Open Item 3.2.12-2
Please see response to SER Open Item 3.2.12-1 for SSF heat exchanger information. The remainder of this Open Item response pertains to the Decay Heat Coolers and Reactor Building Cooling Units only.

Total containment heat removal capability is determined by the combined heat removal capabilities of the Decay Heat Coolers and Reactor Building Cooling Units in conjunction with the Reactor Building Spray System. The acceptance criteria for the Decay Heat Coolers and the Reactor Building Cooling Units is that total containment heat removal capability exceed the design basis required containment heat removal capability. Test results are used in calculations that project the heat removal capability through the upcoming fuel cycle and compare it to the design basis required heat removal capability. Heat removal capabilities of the Reactor Building Cooling Units and Decay Heat Coolers are interdependent. When heat exchanger performance test data are collected for the Reactor Building Cooling Units and Decay Heat Coolers, the data is used to effectively calculate a heat transfer coefficient for each cooler. This heat transfer coefficient is then used to calculate heat removal capability in normal and accident conditions using variables that apply to normal and accident conditions, such as lake temperature and Reactor Building atmospheric temperature. These calculations use the test data to prove that total required containment heat removal capability of the Reactor Building Cooling Units, Decay Heat Coolers, and Reactor Building Spray System during normal and accident conditions exists. If calculations show acceptance criteria are not met, the coolers are cleaned. For more information on cleaning of these coolers, refer to response to RAI 4.17-1. Details on performance relative to conditions of the test setup and the models used to analyze test data can be found in Section 6.2.1.1.3, Subsection "Containment Heat Removal Systems", of the Oconee UFSAR.

Because the decay heat coolers can only be tested during a refueling outage, an additional conservatism is applied to heat transfer value acceptance criteria to ensure operation under all design basis scenarios. A 4% degradation in heat transfer capacity is imposed on the Decay Heat

Coolers above and beyond the requirement that the total containment heat removal exceed its design basis requirement. This 4% criteria is based on testing and operating experience. Historically, testing has shown that less than 4% degradation is expected during a normal operating cycle. Therefore, if 4% degradation is detected, corrective action to chemically clean the coolers is implemented. This degradation criteria is not part of the design basis of the coolers, it is simply in place as a conservative measure to ensure that corrective actions are taken before the heat removal capabilities of the containment heat removal systems approaches the design basis limit. This 4% degradation criteria is not applied to the Reactor Building Cooling Units. While the Decay Heat Coolers can only be tested during a refueling outage, the Reactor Building Cooling Units can be tested any time during unit operation and are tested quarterly. Since frequent testing allows for more effective trending on the Reactor Building Cooling Units, the additional 4% degradation criteria is not imposed upon them.

SER Open Item 3.2.13-1 – As stated on page 4.25-1, under Section 4.25.1, the scope of the service water piping corrosion program includes all bronze, carbon steel, cast iron and stainless steel components exposed to raw water and included within the scope of license renewal. The staff requests that the applicant discuss how loss of material is managed for the other material types exposed to raw water (e.g., copper, brass, and ductile iron).

Duke Response to SER Open Item 3.2.13-1
Note: The response to this open item will also address Open Items 3.2.13-2, 3.2.13-3, and 3.2.13-4.

The purpose of the Service Water Piping Corrosion Program is to assess and manage loss of material due to corrosion for the various component materials in Oconee, Keowee and Standby Shutdown Facility raw water systems that may challenge the component intended function of pressure boundary. The brass, bronze, copper, carbon steel and cast iron component materials can experience loss of material from both general corrosion and localized corrosion (pitting and microbiologically influenced corrosion (MIC)) due to exposure to the waters of Lake Keowee. Stainless steel component materials do not experience loss of material due to general corrosion, but can experience localized corrosion due to pitting and MIC. The following raw water systems within the scope of license renewal are within the scope of the Service Water Piping Corrosion Program:

- Auxiliary Service Water System
- Condenser Circulating Water System
- Essential Siphon Vacuum System
- High Pressure Service Water System
- Low Pressure Injection System (for the raw water side of the Decay Heat Cooler cooled by water supplied by the Low Pressure Service Water System)
- Low Pressure Service Water System
- Standby Shutdown Facility (SSF) Auxiliary Service Water System
- Service Water System (Keowee)
- Turbine Generator Cooling Water System (Keowee)
- Turbine Sump Pump System (Keowee)

The Service Water Piping Corrosion Program is not focused on components within each specific system, but is more broadly focused across all of the system components within license renewal that are susceptible to the various corrosion mechanisms. The intent of the Service Water Piping Corrosion Program is to inspect a number of locations with conditions that are characteristic of the conditions found throughout the raw water systems above. The results of these inspection locations would then be extrapolated to similar locations throughout all the raw water systems within the scope of license renewal. This characteristic-based approach recognizes the commonality among the component materials of construction and the environment to which they are exposed. In this way, components within the raw water systems at Keowee are linked to the

results of the inspections of other raw water systems at Oconee and the Standby Shutdown Facility.

As an example, the inspection results of a carbon steel pipe in a stagnant location in the Low Pressure Service Water System at Oconee would be indicative of the condition of a carbon steel pipe in a stagnant location in the Turbine Generator Cooling Water System at Keowee. Both systems have carbon steel pipe in a stagnant location exposed to raw water from Lake Keowee. Both have operated a similar length of time under similar conditions. Therefore, the inspection results of the carbon steel pipe in the Low Pressure Service Water System will be characteristic of the condition of the carbon steel pipe in the Turbine Generator Cooling Water System at Keowee.

This characteristic-based approach to managing aging effects is also used for materials that behave similarly, but are not constructed from the same material specification. For example, due to the similarity between cast iron and carbon steel, operating experience has shown that the corrosion performance of cast irons and carbon steels is very similar. Monitoring of carbon steel piping for loss of material would serve as an indicator of the condition of the cast iron components in the raw water systems. Corroded carbon steel piping would be an indicator of corroded cast iron components.

Another example of materials that will behave similarly when exposed to raw water are copper, brass and bronze. For these materials, Duke noted during preparation of the Oconee License Renewal Application that the Service Water Piping Corrosion Program contained no inspection locations for monitoring the condition of copper, brass, and bronze components. Duke determined that a program enhancement was needed for license renewal to add inspection locations that monitored the condition of these materials. Since copper and bronze are, in general, more corrosion resistant than brass to natural waters, Duke determined that monitoring brass piping in Keowee raw water systems for loss of material will serve as an indicator of the condition of brass, bronze, and copper components exposed to raw water in other systems at Oconee and the Standby Shutdown Facility. As stated on page 4.25-2 of Exhibit A of the Application, under Section 4.25.1, the second paragraph of the scope notes that the Service Water Piping Corrosion Program will be enhanced to include piping inspection locations at Keowee, focused on bronze and brass piping. (As an aside, subsequent to application submittal, Duke has discovered that no bronze piping exists in the raw water systems at Keowee, Oconee, and the SSF. Therefore, this program enhancement will only add brass piping inspection locations.)

For the carbon steel, cast iron, copper, brass, and bronze component materials that can experience loss of material from both general corrosion and localized corrosion (pitting and MIC), it is the gross material loss due to generalized corrosion that is of primary concern under the Service Water Piping Corrosion Program. Gross wall loss can lead to structural instability concerns and could directly impact component intended function. Monitoring for loss of material due to general corrosion is accomplished using ultrasonic test techniques (UT),

supplemented by visual inspections if access to the interior surfaces is allowed such as during plant modifications.

Localized corrosion due to pitting and MIC will reveal itself through pinhole leaks in the piping components. The geometry of the pinholes means that they are not a structural integrity concern. Further, these pinhole leaks cannot individually lead to loss of the component intended function, since sufficient flow at prescribed pressures can still be provided by the system. These localized concerns will lead to structural integrity concerns only when a significant number of pinholes are present. A review of recent Oconee operating experience does not show any incidences of pitting corrosion and/or MIC of components that could lead to structural integrity concerns. To manage any future pitting corrosion and MIC, the Service Water Piping Corrosion Program will be enhanced to document the relevant Oconee operating experience associated with incidents of through-wall leaks due to localized corrosion. A trend of indications of through-wall leaks due to pitting corrosion or MIC will provide evidence when localized corrosion may become a structural integrity concern and will trigger corrective actions by the Service Water Piping Corrosion Program. Methods in place to identify incidents of through-wall leaks are system walkdowns, operator rounds, system testing, and maintenance activities. This relevant operating experience will form the basis for any future programmatic actions with respect to pitting corrosion and MIC concerns.

Stainless steel components have been added in recent years to raw water systems in response to fouling, not corrosion, problems occurring in small diameter carbon steel pipe. These stainless steel components could experience loss of material due to pitting and MIC. If a significant number of pinholes were to develop and if they were left unmanaged, they could ultimately challenge component intended function. The staff is correct in noting that there is no relationship between the course of general corrosion of carbon steel components and pitting or MIC of stainless steel components or components constructed of other materials. The staff is also correct that UT is not very effective in detecting pitting or MIC. UT is credited for managing general corrosion only. To manage any future pitting corrosion and MIC, the Service Water Piping Corrosion Program enhancements previously described will manage localized corrosion of stainless steel components in a raw water environment.

While the emphasis in the Service Water Corrosion Program remains on gross material loss, the loss of material due to localized corrosion of component materials exposed to raw water will be managed by the monitoring and trending of relevant Oconee operating experience of non-structural, through-wall leaks identified during various plant activities.

SER Open Item 3.2.13-2 – The applicant stated that the focus of the service water piping corrosion program to date is on the carbon steel piping components exposed to raw water because they are the most susceptible to general corrosion and can serve as a leading indicator of the general material condition of the system components (page 4.25-1). Thus, the staff assumes that the applicant has not performed and has no plans to perform inspections of components fabricated from materials other than carbon steel. The staff is unaware of any relationship between the course of general corrosion of carbon steel components and pitting or MIC attack of

stainless steel components. The staff requests the applicant provide the technical basis for relying on inspections of carbon steel components for general corrosion to "serve as a leading indicator" of the condition of other components made of materials other than carbon steel and susceptible to other corrosive mechanisms such as pitting or MIC.

Duke Response to SER Open Item 3.2.13-2
See response to Open Item 3.2.13-1.

SER Open Item 3.2.13-3 – The applicant stated that the program does not currently include inspections of the Keowee systems because the components in that system remain bounded by the overall program results. The staff requests the applicant to state specifically how the Keowee system is bounded.

Duke Response to SER Open Item 3.2.13-3
See response to Open Item 3.2.13-1.

SER Open Item 3.2.13-4 – The applicant inspects the bounding locations using ultrasonic test techniques (UT), supplemented by visual inspections if access to the interior surfaces is allowed such as during plant modifications. The staff finds this technique acceptable for detecting general corrosion of carbon steel, but questions the validity of this technique for detecting localized degradation such as pitting or MIC in stainless steel. The staff requests the applicant to describe more fully its inspection technique to justify the use of UT for localized degradation.

Duke Response to SER Open Item 3.2.13-4
See response to Open Item 3.2.13-1.

SER Open Item 3.3.3.1-1 – In Section 3.3.4.2 of Exhibit A of the LRA, Duke emphasizes that in spite of the water infiltration and high humidity in the ONS tendon galleries, the tendon components are well protected. Based on the information contained in the database on the condition of the tendon grease caps and the bearing plates in tendon galleries (see Plates 2, 7, and 11 in Appendix A of NUREG-1522, "Assessment of Inservice Conditions of Safety-Related Nuclear Plant Structures"), the staff does not agree with the applicant's conclusion. The intended function of the post-tensioning system is to impose compressive forces on the concrete containment structure to resist the internal pressure resulting from a design-basis accident with no loss of structural integrity. Operational experience, as documented in NUREG-1522, has shown that water infiltration and high humidity in the tendon gallery can be a significant aging effect on the vertical tendon anchorages that could potentially result in loss of the ability of the post-tensioning system to perform its intended function. Therefore this aging effect needs to be adequately considered.

Duke Response to SER Open Item 3.3.3.1-1
Loss of material due to corrosion was determined to be an applicable aging effect for the tendon anchorage as described in Section 3.3.4.5 of Exhibit A of the Application. The *Containment Inservice Inspection Program* is credited with managing loss of material due to corrosion of the tendon anchorage for the extended period of operation. The *Containment Inservice Inspection Program* is discussed in Section 4.8 of Exhibit A. As part of the *Containment Inservice Inspection Program*, the tendon anchorage are inspected for loss of material due to corrosion in accordance with ASME Section XI Subsection IWL. Based on the discussion in Section 4.8 of Exhibit A of the Application, the implementation of the *Containment Inservice Inspection Plan* provides reasonable assurance that the aging effects of the tendon anchorage, including those located in the gallery, will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

SER Open Item 3.4.3.2-1 – The LRA states that the aging effect for the spray head is cracking due to reduction in fracture toughness. The staff does not agree since reduction in fracture toughness does not cause cracking. Reduction in fracture toughness causes cracked components to fail at lower stresses than they otherwise would fail, but reduction in fracture toughness is not the cause of the cracking. The staff believes that the aging effects for the spray head are cracking and reduction in fracture toughness due to thermal aging of the cast stainless steel. Until Duke has responded to this apparent discrepancy, the staff cannot conclude that Duke has properly identified the potential aging effects for the heater bundle penetration welds, cladding, spray line and spray head.

Duke Response to SER Open Item 3.4.3.2-1
This topic was briefly discussed with the staff during a meeting held on August 24, 1999. Duke agrees with the staff that the applicable aging effects for the pressurizer spray head are cracking by fatigue and reduction of fracture toughness by thermal embrittlement. These aging effects will be managed by the Pressurizer Cladding, Internal Spray and Spray Head Examination described in Section 4.3.7.1 of Exhibit A of the Application. Please see also our response to SER Open Item 3.4.3.3-5.

SER Open Item 3.4.3.2-2 – Section 3.1 of topical report BAW-2248 dismisses changes in dimensions of the RVI components due to void swelling as a significant aging effect because there is no of evidence of void swelling under PWR conditions. However, EPRI TR-107521 "Generic License Renewal Technical Issues Summary," cites several sources with different estimates of void swelling. One source predicts swelling as great as 14 percent for PWR baffle-former assemblies over a 40-year plant lifetime, whereas another source states that swelling would be less than 3 percent for the most highly irradiated sections of the internals at 60 years. The issue of concern to the staff is the effect of change of dimensions due to void swelling on the ability of the RVI to perform their intended function. Duke must provide the basis for concluding that void swelling is not an issue for RVI or must provide an AMP.

Duke Response to SER Open Item 3.4.3.2-2
The topic of void swelling in reactor vessel internals was discussed with the staff during a meeting on July 19, 1999. Subsequent to this meeting, in a letter dated August 16, 1999 to the staff, the B&W Owners Group provided additional information on the topic of void swelling. Duke Energy agrees that void swelling is an aging effect that may be occurring.

Duke Energy also agrees with the comments provided by the ACRS in their letter to the staff dated September 13, 1999 on the topic of void swelling. In this letter, the ACRS agreed that "additional research and experience are needed to determine the significance of void swelling as a potential mode of degradation for pressurized water reactor internals." The ACRS goes on to state that a focused inspection program as suggested by the staff is appropriate.

Void swelling is addressed in the *Reactor Vessel Internals Aging Management Program* description provided immediately after the Duke response to SER Open Item 3.4.3.3-7.

Duke Energy believes that there is potential for void swelling in localized areas of high fluence and high temperature (due to gamma heating) late in plant life. Therefore, there is time to perform the necessary activities to determine the significance of the potential swelling degradation. The current ASME Section XI inspection requirements (Subsection IWB, Table IWB-2500, Examination Category B-N-3) for the reactor vessel internals will be effective in determining any gross deformation by void swelling of the baffle and former plates if it were to occur. The Oconee Inservice Inspection Plan, which implements the requirements of ASME Section XI, is described in Section 4.18 of Exhibit A of the Application.

SER Open Item 3.4.3.3-1 – The surface examination will be a one-time inspection performed when a heater bundle is removed. If the results are not acceptable, they may be used as a baseline for establishing a longer term programmatic action covering all ONS pressurizer heater bundles. However, Duke has not stated when the heater bundle will be removed for examination and the basis for scheduling the inspection.

Duke Response to SER Open Item 3.4.3.3-1
As described in Section 4.3.7.2 of Exhibit A of the Application, the surface examination of a sample population of peripheral pressurizer heater bundle penetration structural welds on one Unit 1 heater bundle will be performed when a heater bundle is replaced. Replacement of the bundle would occur as a result of the inability to meet operational requirements for heater operation owing to inoperable heater elements. Heater bundle replacement may occur either prior to the period of extended operation or during the period of extended operation.

Duke believes that this inspection may 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.

It is unreasonable to remove an operable heater bundle assembly that remains functional. In order to inspect the heater sheath-to-heater sleeve structural welds and heater sleeve-to-diaphragm plate structural welds, the seal welds for the diaphragm plate made from Alloy 82/182 welds must be cut and the bundle removed. The cutting and rewelding of the Alloy 82/182 seal weld may increase the likelihood of cracking by PWSCC (implies that seal weld is a structural weld but is not—essentially a permanent gasket). Ultimately, leakage at the seal weld can have a higher consequence on the functionality of the pressurizer and may lead to steam cutting and loss of material at or near the bolted connection to the pressurizer shell.

The delay in inspecting the partial penetration welds within the Unit 1 pressurizer heater bundles is reasonable. In the unlikely event that the partial penetration weld develops a crack, minor leakage may develop at the pressurizer heater bundle. The Reactor Coolant system pressure boundary is routinely monitored for indications of leakage. During normal operation (Modes 1, 2, ,3 and 4), Reactor Coolant System Operational Leakage Monitoring is performed in accordance with Oconee Technical Specification 3.4.13. Evaluations to determine operational leakage are performed at least every 72 hours. In the event that the calculated leakage exceeds limits specified in the technical specifications, actions are taken to identify and eliminate the source of leakage or to shut down the unit.

In addition to the above surveillance performed during operation, the Reactor Coolant System external surfaces, including the pressurizer heater bundles, are visually examined during each refueling outage, in accordance with ASME Section XI inspection requirements (Subsection IWB, Table IWB-2500, Examination Category B-P). The inspectors are trained to look for indications of leakage anywhere in the vicinity of the Reactor Coolant System. The area in the vicinity of the pressurizer heater bundles is insulated with stainless steel mirror insulation. This insulation does not absorb moisture. Any leakage from the Reactor Coolant System pressure boundary would reveal itself at the low points of the insulation or on the Reactor Building floor. In the unlikely event that leakage is observed, actions are taken to identify and eliminate the source of leakage. If the leakage were from the heater bundle, the bundle would be either repaired or replaced.

SER Open Item 3.4.3.3-2 – For ONS Unit 1, Duke proposes to inspect the heater-sheath-to-sleeve penetration welds, but not the heater-sleeve-to-heater-bundle diaphragm plate. The ONS Unit 1 heater sleeves and heater bundle diaphragm plates are fabricated from Alloy 600, which is susceptible to PWSCC. Hence, both the heater-sheath-to-sleeve plate and the heater-sleeve-to-bundle diaphragm plate need to be inspected to determine whether the Alloy 600 materials in the heater bundle have experienced PWSCC. The heater sheaths and heater bundle diaphragm plates in ONS Units 2 and 3 are stainless steel. Therefore, they are not susceptible to PWSCC. The ONS Unit 1 heater bundles are susceptible to PWSCC and the ONS Unit 2 and 3 heater bundles are not. Therefore, the scope of the inspection of Unit 1 should be expanded to include the heater sheath-to-sleeve plate and the heater-sleeve-to-bundle diaphragm plate.

Duke Response to SER Open Item 3.4.3.3-2

The Unit 1 heater bundle inspection will be revised to include inspections of the heater sheath-to-heater sleeve structural weld and the heater sleeve-to-heater bundle diaphragm plate structural weld (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not required.

SER Open Item 3.4.3.3-3 – For detection of cracking, the NRC staff proposed to the B&WOG a modified approach to manage cracking of RVI non-bolting components. This approach involves a supplemental (enhanced VT-1) examination of the components believed to be the limiting components for cracking, considering the susceptibility of the components to the aging mechanisms the material properties of the components (in particular the fracture toughness), and the operating stresses on the components. Initial consideration by the B&WOG indicated that the limiting components with respect to highest neutron fluence were the baffle plates and baffle-former bolts. These examinations would be included as part of the 10-year ISI program. Since the examination addresses the limiting components, plant-specific neutron fluence evaluations are not necessary. Duke has not identified the limiting components and incorporate this program into the ISI program.

Duke Response to SER Open Item 3.4.3.3-3
The Oconee *Reactor Vessel Internals Aging Management Program* includes the *Inspection of Non-Bolted Items.* An initial description of this inspection was presented to the staff during a meeting held on July 19, 1999 (See NRC meeting summary dated August 2, 1999). The current description of this inspection is provided within the overall *Reactor Vessel Internals Aging Management Program* description provided immediately after the Duke Response to SER Open Item 3.4.3.3-7.

SER Open Item 3.4.3.3-4 – A specific RVI component that has demonstrated susceptibility to IASCC (although not specifically in B&W nuclear steam supply systems) is the baffle-former bolts. At the present there are no requirements for supplemental examination of baffle former bolts, and no plans to implement periodic supplemental examinations. This situation may change as several one-time volumetric examination and replacement programs at specific plants are completed and the results are fully analyzed. In response to RAI 12 to topical report BAW-2248, the B&WOG stated that future inspection plans for baffle former-bolts would be on a plant-specific basis, possibly beginning with the inspection at ONS Unit 1 during their fourth inservice inspection (ISI) interval (2003 – 2013). It should be noted that accessibility limitations eliminate visual inspection as a viable alternative for this bolting; a volumetric method is necessary for effective examination. In a February 18, 1999, response to RAI 12 and RAI 13 the B&WOG stated that the renewal applicant would be responsible for using the tools provided by the Issues Task Group (ITG) and the owners groups to determine the necessary steps (e.g., inspections, operability determinations, and replacements) to manage the applicable baffle-bolt aging effects. The ITG on reactor vessel internals is currently addressing the issues of cracking, reduction of fracture toughness, and loss of preload for baffle bolts and associated materials. The data and information acquired from these various ITG activities will be used to determine the necessary steps in managing the issues of baffle bolt age-related degradation, including future inspection plans. These plans are expected to be outlined on a plant specific basis, possibly beginning with the inspection at ONS Unit 1 during their fourth inservice inspection (ISI) interval. Duke did not provide a plant specific plan, therefore, the information requested of the B&WOG about BAW-2248 in a letter dated December 2, 1998, for RAI 12 and RAI 13 with regard to the aging management of the effects of baffle bolt age-related degradation is an Open Item.

Duke Response to SER Open Item 3.4.3.3-4
(SER Open Item 3.4.3.3-4 is equivalent to BAW-2248 renewal applicant action item (4). The following response is intended to address both of these items.)

The Oconee *Reactor Vessel Internals Aging Management Program* includes the *Baffle Bolt Inspection.* An initial description of this inspection was presented to the staff during a meeting held on July 19, 1999 (See NRC meeting summary dated August 2, 1999). The current description of this inspection is provided within the overall *Reactor Vessel Internals Aging Management Program* description provided immediately after the Duke Response to SER Open Item 3.4.3.3-7.

SER Open Item 3.4.3.3-5 – The RVI components fabricated from CASS are potentially subject to a synergistic loss of fracture toughness due to the combination of thermal and neutron irradiation embrittlement. To account for this synergistic loss of fracture toughness, a modified approach for CASS RVI components is proposed. This modified approach would involve either a supplemental (enhanced VT-1) examination of the affected components as part of Duke's 10-year ISI program during the period of extended operation or a component-specific evaluation to determine the susceptibility to loss of fracture toughness. For the component-specific evaluation refer to "Embrittlement of CASS RVI Components" in Section 3.4.3.3 of this SER.

In addition, to determine whether CASS components are above or below the effective threshold value of 1×10^{17} n/cm^2, discussed above, Duke must provide estimates of the neutron fluence of each CASS component at the expiration of the license renewal term, identify the method of determining the neutron fluence, and provide justification for applicability of the method to components above or below the core.

Note: In addition to the above Section 3.4.3.3 also contains the following references to this open item:

Open Item 3.4.3.3-5 described under the heading "Embrittlement of CASS RVI Components" also applies to valve bodies in the RCS piping.

The reduction in fracture toughness due to thermal embrittlement is a significant factor in cast stainless steel components that do not satisfy the criteria specified by the staff in this section (criteria are discussed under "Embrittlement of CASS RVI Components"). This is part of Open Item 3.4.3.3-5, which is discussed later in this section. If the ONS pressurizer spray heads do not satisfy these criteria, they could be subject to significant thermal embrittlement and the proposed examination may require an enhanced VT-1 examination.

Duke Response to SER Open Item 3.4.3.3-5
As background, a larger set of issues associated with cast austenitic stainless steels (CASS) in the Reactor Coolant System (RCS) has been reviewed by Duke and the NRC staff while developing the response to this item. Specifically, issues associated with the presentation of the aging management of CASS components in the Oconee License Renewal Safety Evaluation Report have been under review. A meeting was held August 24, 1999 between Duke and the NRC staff to discuss issues associated with these CASS components.

The NRC meeting summary dated September 9, 1999 captures the insights from this meeting. A summary of the understanding from the meeting are offered here as a response to this open item. In the meeting, four groups of CASS components were recognized in the Oconee RCS: (1) RCS boundary isolation valves, (2) reactor coolant pump (RCP) casings, (3) the pressurizer spray head, and (4) parts of the reactor vessel internals. Also discussed was the susceptibility screening logic, such as that contained in EPRI TR-106092 and expanded on in the NRC staff SER, to be used to identify susceptible CASS components for further inspection or evaluation. Each of the

four groups of CASS components were reviewed. An understanding was reached for the actions appropriate for each group of CASS components.

For group (1) CASS RCS boundary isolation valves, Duke and the NRC staff agree that the applicable ASME Section XI examinations when coupled with specifically defined fracture mechanics analysis requirements are sufficient to manage reduction of fracture toughness in the CASS valve bodies. Because of the similarities in fracture toughness between thermally aged CASS with delta ferrite less than 25 percent and stainless steel submerged-arc welds (SAWs), any required flaw evaluation would be done in accordance with IWB-3640. If they had exceeded the 25 percent value, any flaw evaluations would have been treated on a case by case basis. The details of this process are described in the Oconee License Renewal Application Section 4.18.2.

For group (2) RCP casings, Duke and the NRC staff agree that an evaluation in accordance with ASME Code Case N-481 is sufficient to address the CASS RCP casings. Should the code case not be invoke, the screening criteria described in EPRI TR-106092 and expanded on in the SER would be applied to determine the susceptibility to loss of fracture toughness. Susceptible RCP casings would be managed in accordance with applicable ASME Section XI examinations. When these examinations are coupled with the specifically defined fracture mechanics analysis requirements described above, they will be sufficient to manage reduction of fracture toughness in the CASS RCP casings. At the time of this response, Duke has invoked Code Case N-481 for Oconee 2 and 3 and has not invoked it for Unit 1. Unit 1 pump design differs from Units 2 and 3 as described in Section 2.4.8 of Exhibit A of the Application. The delta ferrite levels of the Unit 1 pump casings are less than 25 percent, so IWB-3640 can be applied.

For the group (3) pressurizer spray head, Duke and the NRC staff agree that cracking and loss of fracture toughness are the applicable aging effects for the spray head. An examination of the spray head is included with the Pressurizer Cladding, Internal Spray and Spray Head Examination described in Section 4.3.7.1 of Exhibit A of the Application. Please see also our response to SER Open Item 3.4.3.2-1.

For group (4) CASS items in the reactor vessel internals (RVI), the Oconee *Reactor Vessel Internals Aging Management Program* includes the *Inspection of CASS RVI Items.* The current description of this inspection is provided as a part of the overall *Reactor Vessel Internals Aging Management Program* description provided immediately after the Duke Response to SER Open Item 3.4.3.3-7.

SER Open Item 3.4.3.3-6 – Besides visual inspection (VT-3) in accordance with Examination Category B-N-3 of the ASME Code Section XI inservice inspection program, the response to RAI 5 on the topical report cited by the LRA, BAW-2248, states that aging management for vent valve bodies and retaining rings is also accomplished through vent valve testing and visual inspection requirements (at each refueling outage) in accordance with the Pump and Valve In-Service Test Program at ONS Units 1, 2, and 3. A description of this program must be included in the LRA to allow an evaluation. The vent valve retaining rings (fabricated from precipitation-hardened stainless steel) should be subject to supplemental (enhanced VT-1) examination. This examination could be modified or eliminated, provided that Duke can demonstrate through data (including microstructural considerations) and evaluation that loss of fracture toughness by thermal embrittlement and/or neutron irradiation embrittlement is not significant for the vent valve retaining rings. Such a demonstration could use the same framework as proposed for CASS RVI components.

Duke Response to SER Open Item 3.4.3.3-6

The reactor vessel internals vent valves allow flow out of the core to the broken cold leg in the event of a cold leg LOCA to prevent pressure from building in the core and restricting core cooling. The vent valves open on differential pressure. The primary means to inspect the vent valves at Oconee is the general visual inspection required by Examination Category B-N-3.

The Oconee Pump and Valve Inservice Test Program implements the requirements of 10 CFR 50, §50.55a. The reactor vessel internals vent valves are identified in the program. The valves are self-actuated check valves. A full-stroke test of each valve is performed every refueling outage. The plant procedure that implements the vent valve exercise test also requires that each valve seat be inspected for visible damage.

In addition to the testing described above to manage the effects of aging, Oconee credits the *Reactor Vessel Internals Aging Management Program.* The Oconee *Reactor Vessel Internals Aging Management Program* includes the *Inspection of CASS RVI Items.* The current description of this inspection is provided within the overall *Reactor Vessel Internals Aging Management Program* description provided immediately after the Duke Response to SER Open Item 3.4.3.3-7.

SER Open Item 3.4.3.3-7 – The loss of fracture toughness in CASS is caused by thermal embrittlement at reactor operating temperatures. EPRI topical report TR-106092 discusses the effect of thermal embrittlement on CASS and describes a program for detecting the loss of fracture toughness. The staff has reviewed this topical report and concluded that CASS components must be evaluated to the criteria in EPRI TR-106092 and the additional criteria described previously under the heading "Embrittlement of CASS RVI Components."

Duke Response to SER Open Item 3.4.3.3-7
On August 24, 1999, a meeting was held between Duke and the NRC staff to discuss several issues associated with CASS items at Oconee. The NRC meeting summary dated September 9, 1999 captures the insights from this meeting. The discussions clarified the four groups of CASS Reactor Coolant System components and the aging management activities associated with each group. Specific issues associated with the use of the CASS component susceptibility screening criteria in EPRI TR-106092 were discussed. A more complete description of the outcome of this meeting is contained in the response to Safety Evaluation Report Open Item 3.4.3.3-5.

Reactor Vessel Internals Aging Management Program

The Oconee *Reactor Vessel Internals Aging Management Program* consists of the following three major activities:

- Characterization of aging effects,
- Analyses, and
- Inspections

Characterization of Aging Effects

The Oconee *Reactor Vessel Internals Aging Management Program* includes the characterization of the aging effects for baffle bolting, non-bolted items, and CASS Reactor Vessel Internals items. The scope of the characterization includes the following aging effects: (1) cracking due to irradiation assisted stress corrosion cracking, (2) reduction of fracture toughness due to irradiation embrittlement and thermal embrittlement, and (3) dimensional changes due to void swelling.

Analyses

The Oconee *Reactor Vessel Internals Aging Management Program* includes several analyses. These analyses will be performed to determine the number of baffle bolts that must remain intact in order to maintain functionality of the reactor vessel internals. Analyses will also be performed to determine critical crack sizes of the non-bolted items within the reactor vessel internals. These analyses will address the topics of interest described in SER Open Item 4.2.5.3-1. Finally, analyses will be performed to determine the critical crack sizes of the CASS reactor vessel internals items. Critical locations for baffle bolting, non-bolted items, and CASS reactor vessel internals items will also be determined by these analyses.

The above activities will be used in the preparation of the Reactor Vessel Internals inspections described below. Current plans are to complete the above characterizations and analyses at least three years prior to the outages in which the inspections are to be performed. Timely completion of these activities will allow the inspection to be finalized and the inspection to occur as committed.

Inspections

The Oconee *Reactor Vessel Internals Aging Management Program* includes of the following three interrelated inspections:

1. Baffle Bolt Inspection
2. Inspection of Non-Bolted Items
3. Inspection of Cast Austenitic Stainless Steel (CASS) Reactor Vessel Internals(RVI) Items

The purpose of the *Reactor Vessel Internals – Baffle Bolt Inspection* is to assess the condition of the baffle bolts in order to confirm the required number of baffle bolts remain functional,

ensuring the functionality of the reactor vessel internals. Activities are currently in progress to develop and qualify the inspection method.

The purpose of the *Reactor Vessel Internals – Inspection of Non-Bolted Items* is to assess the condition of the non-bolted items (e.g. plates, forgings and welds) in order to ensure aging effects are not adversely affecting the functionality of the reactor vessel internals. Activities are currently in progress to develop and qualify the inspection method.

The purpose of the *Reactor Vessel Internals – Inspection of CASS RVI Items* is to ensure that the reduction of fracture toughness properties of these items will not result in loss of the component intended functions of the reactor vessel internals during the period of extended operation. The reactor vessel internals items fabricated from CASS 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.

Collectively, these inspections will provide additional assurance that the Oconee reactor vessel internals will remain functional through the period of extended operation.

These three inspections are described on the following pages.

REACTOR VESSEL INTERNALS – BAFFLE BOLT INSPECTION

Purpose – The purpose of the *Reactor Vessel Internals – Baffle Bolt Inspection* is to assess the condition of the baffle bolts in order to confirm the required number of baffle bolts remain functional, ensuring the functionality of the reactor vessel internals.

Scope – The scope of this inspection consists of the reactor vessel internals baffle bolts for Oconee Units 1, 2 and 3.

Aging Effects – The aging effects of concern are (1) cracking due to irradiation assisted stress corrosion cracking, (2) reduction of fracture toughness due irradiation embrittlement, and (3) dimensional changes due to void swelling.

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

Sample Size – The sample size will be a selected number of baffle bolts from one Oconee reactor vessel internals.

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

Frequency – The *Reactor Vessel Internals – Baffle Bolt Inspection* is a one-time inspection.

Acceptance Criteria or Standard – Any detectable crack indication is unacceptable for a particular bolt. The number of bolts needed to be intact and their locations will be determined by analysis.

Corrective Action – The need for subsequent examinations will be determined after the results of the initial examination are available. 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 to inspect or replace baffle bolts in all three Oconee units. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity – Following issuance of the renewed operating licenses for Oconee Nuclear Station, this inspection will be performed during the 4th 10-year inservice inspection interval of the Oconee unit being inspected.

Administrative Controls – The *Reactor Vessel Internals – Baffle Bolt Inspection* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis – Renewal Applicant Action Item 4.1 (4) in the Safety Evaluation Report for BAW-2248A.

REACTOR VESSEL INTERNALS – INSPECTION OF NON-BOLTED ITEMS

Purpose – The purpose of the *Reactor Vessel Internals – Inspection of Non-Bolted Items* is to assess the condition of the non-bolted items (e.g. plates, forgings and welds) in order to ensure aging effects are not adversely affecting the functionality of the reactor vessel internals.

Scope – The scope of this inspection consists of the reactor vessel internals stainless steel non-bolted items (e.g., plates, forgings and welds) for Oconee Units 1, 2 and 3.

Aging Effects – The aging effects of concern are (1) cracking due to irradiation assisted stress corrosion cracking, (2) reduction of fracture toughness due irradiation embrittlement, and (3) dimensional changes due to void swelling.

Method – Current plans are to perform a visual inspection of the non-bolted items. Activities are in progress to develop and qualify the inspection method.

Sample Size – The sample size will be a selected region of the most-limiting non-bolted item at one Oconee unit.

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

Frequency – The *Reactor Vessel Internals – Inspection of Non-Bolted Items* is a one-time inspection.

Acceptance Criteria or Standard – Critical crack size will be determined by analysis. Acceptance criteria will be developed prior to inspection.

Corrective Action – The need for subsequent examinations will be determined after the results of the initial examination are available. 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 to inspect or replace baffle bolts in all three Oconee units. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity – Following issuance of the renewed operating licenses for Oconee Nuclear Station, this inspection will be performed during the 4th 10-year inservice inspection interval of the Oconee unit being inspected.

Administrative Controls – The *Reactor Vessel Internals – Inspection of Non-Bolted Items* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*

Regulatory Basis – Renewal Applicant Action Item 4.1 (TBD) in the Safety Evaluation Report for BAW-2248A.

REACTOR VESSEL INTERNALS – INSPECTION OF CASS RVI ITEMS

Purpose – The purpose of the *Reactor Vessel Internals – Inspection of CASS RVI Items* is to ensure that the reduction of fracture toughness properties of these items will not result in loss of the component intended functions of the reactor vessel internals during the period of extended operation.

Scope – The scope of this inspection consists of reactor vessel internals items fabricated from CASS (e.g. control rod guide tube spacers, vent valve bodies, Unit 3 outlet nozzles, and incore guide tube assembly spiders) for Oconee Units 1, 2, and 3. The vent valve retaining rings, fabricated from martensitic stainless steel, are also included in this inspection.

Aging Effects – The aging effects of concern for the reactor vessel internals items fabricated from CASS and martensitic steel are reduction of fracture toughness by thermal embrittlement and irradiation embrittlement.

Method – Reduction of fracture toughness cannot be measured through traditional in-situ examination techniques, thus necessitating an analytical approach to assess the effect of reduction of fracture toughness on the applicable reactor vessel internals items. The specific inspection method will depend on the results of these analyses.

Sample Size – The sample size will be determined concurrently with the determination of the inspection method above.

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

Frequency – The *Reactor Vessel Internals – Inspection of CASS RVI Items* is a one-time inspection.

Acceptance Criteria or Standard – Critical crack size will be determined by analysis. Acceptance criteria will be developed prior to inspection.

Corrective Action – The need for subsequent examinations will be determined after the results of the initial examination are available. 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 to inspect or replace baffle bolts in all three Oconee units. Specific corrective actions will be implemented in accordance with the *Duke Quality Assurance Program.*

Timing of New Program or Activity – Following issuance of the renewed operating licenses for Oconee Nuclear Station, this inspection will be performed during the 4th 10-year inservice inspection interval of the Oconee unit being inspected.

Administrative Controls – The *Reactor Vessel Internals – Inspection of CASS RVI Items* will be implemented by plant procedures in accordance with the *Duke Quality Assurance Program.*
Regulatory Basis – Renewal Applicant Action Item 4.1 (TBD) in the Safety Evaluation Report for BAW-2248A.

SER Open Item 3.4.3.3-8 – Loss of material and cracking (not thermal or vibration-induced) are identified in Section 3.4.10.2 as the applicable aging effects for the letdown coolers. These aging effects are managed by the chemistry control program and RCS operational leakage monitoring. The applicant is requested to provide its evaluation of the damage to the various components of the letdown coolers or the specific analyses performed to assure that the four repaired coolers have experienced no degradation as a result of improper operation. Further, the applicant is requested to provide an analytical assessment to assure that the four repaired letdown coolers are operating in a condition that precludes potential failure due to thermal fatigue during the extended period of operation. The applicant's response did not address this aspect of the issue.

Duke Response to SER Open Item 3.4.3.3-8
Duke has performed a more extensive review of the history of the Oconee letdown coolers. The original coolers were the helical shell and tube type of coolers that were not designed for tube plugging. Due to excessive leakage, several of these coolers were replaced with coolers of the same design. Subsequently, the manufacturer of these original coolers designed a pluggable helical shell and tube type of cooler. As the older design coolers developed non-repairable leaks, they were replaced with the new design. By April 1985 all of the original coolers installed during construction along with the replacements of the older design had been replaced with new pluggable coolers. Since the installation of the pluggable coolers, six leaks have developed in the coolers. Since 1985, two of the pluggable coolers have been retired from further service.

As noted in Section 3.4.10 of Exhibit A of the Oconee License Renewal Application, the cause of the failures was attributed to flow induced vibration caused by improper operation. Each unit has two letdown coolers installed in parallel in the High Pressure Injection System. Until 1994, the coolers were operated with one in service and the other in standby. Having one cooler in service with the other in standby resulted in higher than design flow rates that induced vibration in the tube bundle. In 1994, operations were changed to use both coolers simultaneously for the Oconee units.

In these coolers, there are no baffle plates to direct secondary-side flow through the tube bundle. To direct the secondary-side flow properly through the tube bundle, adjacent tubes are stitch-welded together at intervals along the entire length of the bundle. The high flow rates from operation prior to the 1994 changes induced vibration of the tube bundle. This vibration caused the tearing of some stitch-welds which, in turn, propagated through-wall in some tubes. The flawed tubes were detected and plugged.

Since converting to parallel operation in 1994, Oconee has experienced only one tube leak among the six operating coolers. This leak, which occurred shortly after the change in operation, was determined not to be a consequence of the prior operating regime.

Each letdown cooler contains thirty tubes. Loss of the letdown cooler component intended function occurs when five tubes are plugged. When a cooler has five tubes that require plugging, that cooler is retired from service and replaced. Only six leaks have occurred among the six

coolers since the installation of the pluggable design. No installed cooler is close to the functional plugging limit. If a leak were to occur, leakage will be detected by Reactor Coolant System Operational Leakage Monitoring and changes in the Component Cooling System chemistry parameters monitored by the Chemistry Control Program.

Due to radiological concerns, a cooler containing a leaking tube may be physically removed from service, replaced with a spare cooler, and repaired in the hot machine shop. The repaired cooler then becomes the spare. Management of aging effects on the letdown coolers in this manner will assure the coolers can perform their intended function through the period of extended operation.

Finally, the NRC staff has requested an analytical assessment to assure the letdown coolers are operating within a design envelope that would preclude potential cooler failure due to thermal fatigue. The letdown coolers are ASME Section III, Class 3, designed vessels which do not have a prescribed fatigue design envelope. No analytical basis exists to measure the current cooler condition against. Although cracking due to thermal fatigue was not judged to be an applicable aging effect for the coolers, cracking of the tubes within the cooler for other reasons is managed by Reactor Coolant System Operational Leakage Monitoring and the Chemistry Control Program as described above. Revised cooler operation coupled with these aging management programs will assure the coolers remain within their design envelope and will assure proper actions will be taken prior to loss of letdown cooler component intended function.

SER Open Item 3.6.1.3.1-1 – In RAI 3.5.8-3, the staff questioned the applicant's identification of applicable aging effects for the HVAC system. The staff raised a concern that, on the basis of its experience, cracking of ductwork occurs from vibration-induced fatigue and loosening fasteners from dynamic loading, especially in the vicinity of attached device types exposed to dynamic loads such as fans. The applicant responded to RAI 3.5.8-3 by letter dated January 25, 1999, stating that cracking of ductwork from vibrational loads and self-loosening of fasteners from dynamic loading were determined not to be applicable aging effects for the HVAC system. The applicant stated that components within the scope of license renewal are equipped with isolators to prevent transmission of vibration and dynamic loading to the rest of the system. Therefore, vibration-induced fatigue and self-loosening of fasteners are not applicable aging effects for the HVAC system. The staff's review of operating experience is that vibration-induced fatigue and self-loosening of fasteners cannot be avoided by installing isolators. The staff, in a subsequent letter dated April 8, 1999, regarding RAI 3.5.8-3 requested that the applicant address these aging effects or present additional justification for not considering them applicable aging effects. The applicant responded in a letter dated May 10, 1999, that the ONS has had good operating experience with respect to isolators in the auxiliary building ventilation system and control room pressurization and filtration system in preventing the transmission of vibration and dynamic loads to surrounding equipment to preclude cracked ductwork and loosened fasteners. A review of the ONS Problem Investigation Process (PIP) database and ONS-specific licensee event reports did not identify any instances of cracking of ductwork or loosening of fasteners in these two ventilation systems. In addition, these two systems have been in service for more than 25 years and cracking of ductwork and loosening of fasteners would have revealed itself as a concern by now. Therefore, the applicant concluded that cracking of ductwork and loosening of fasteners in the auxiliary building ventilation system and control room pressurization and filtration system are not applicable aging effects for these systems. The staff finds the additional justification presented by the applicant not acceptable for the following two reasons:

In general, sub-component parts of isolators are made of elastomers (such as rubber boots, seals, and flexible collars) and elastomers will degrade from relative motion between vibrating equipment, pressure variations, exposure to temperature changes and oxygen. Because of the degradation of isolators, vibration and subsequent dynamic loads applied to the ductwork and fasteners cannot be eliminated. Although no aging effects (cracking of ductwork and loosening of fasteners) were identified after 25 years of operation, one still cannot ensure that there will not be any degradation of the systems within the next 35 years (the remaining design life plus the extended life). The staff believes that these aging effects are applicable because of the nature of the materials involved.

Duke Response to SER Open Item 3.6.1.3.1-1
Duke understands the staff concern for the aging of the ductwork and fasteners. However, for these items to be impacted by dynamic loading, aging must first affect the elastomers designed to preclude the effects of such relative motion. Rubber boots, seals, and flexible collars in question are elastomers that are a part of the air handling units (source of dynamic loads) located in the Auxiliary Building for the Auxiliary Building Ventilation and Control Room Pressurization and

Filtration Systems (Oconee License Renewal Application Exhibit A, Section 3.5.8). The Penetration Room Ventilation System also discussed in Section 3.5.8 of the Application is constructed of pipe and does not contain these items. These elastomers are used to connect air handling units to adjacent ductwork and have a geometry and material composition that allows relative motion between the air handling unit and adjacent ductwork and prevents the transmission of dynamic loads from the air handling unit to the adjacent ductwork. These elastomers are located in the controlled environment of the Auxiliary Building, but could degrade by hardening over time.

Hardening of the elastomers may lead to other aging effects such as cracking of the ductwork and loosening of fasteners. For license renewal, management of the elastomers such that aging of the ductwork is precluded can be performed for a system if failure of the elastomer and, in turn, the ductwork would lead to loss of component intended function. The Auxiliary Building Ventilation System performs the system intended function of smoke removal during certain fire scenarios. Following a fire in either the control rooms, equipment rooms, or cable rooms, smoke is removed using either installed purge fans or portable purge equipment. The smoke is exhausted into areas in the Auxiliary Building for removal by the Auxiliary Building Ventilation System. Hardening of the elastomers that could lead to cracking of the elastomer and perhaps cracking of ductwork and loosening of fasteners during relative motion would not fail the intended function of smoke removal. Smoke removal would be accomplished with cracks in the elastomer or in the ductwork. Since loss of the elastomer flexibility function or ductwork component intended function would not cause loss of the system intended function, aging management of the elastomers in the Auxiliary Building Ventilation System is not required.

The Control Room Pressurization and Filtration System has a system intended function of providing a suitable environment in the control room following postulated design basis events. In addition, the system must maintain a positive pressure in the control room for accident conditions to prevent unfiltered air from entering the control room. For those items located in the Auxiliary Building, hardening of the elastomers that could lead to cracking of the elastomers and perhaps cracking of ductwork and loosening of fasteners during relative motion could fail the intended functions of this system. For license renewal, managing the aging of the Control Room Pressurization and Filtration System elastomers will preclude the possibility of the aging of the ductwork and loosening of fasteners due to relative motion. The aging management of the elastomers in the Control Room Ventilation System Examination is presented in the response to SER Open Item 2.2.3.4.3.2.1-2.

SER Open Item 3.6.2.3.2-1 – In Section 4.3.10 of Exhibit A of the LRA, Duke described the RCP motor oil collection system inspection. The RCP motor oil collection system inspection will characterize loss of material from corrosion of the carbon steel, brass, copper, and stainless steel components in the RCP motor oil collection system that may periodically be exposed to water from contamination of the oil. Because of the density difference between oil and water, the lower portions of the system have the greatest potential to be exposed to water; thus, the applicant plans to visually inspect one RCP oil collection tank to satisfy the inspection requirement for the entire RCP motor oil collection system. Each ONS unit has four RCP oil collection tanks for a total of 12 tanks. The staff requested that the applicant identify the basis for concluding that the inspection of 1 tank out of 12 provides for an adequate inspection scope. In addition, the staff is unaware of any correlation between general corrosion of carbon steel and other corrosion mechanisms (e.g., crevice corrosion of brass). Thus, the staff also requested that the applicant identify the basis for concluding that the inspection of one carbon steel RCP oil collection tank bounds the other corrosion mechanisms and potentially affected components in the system.

Duke Response to Open Item 3.6.2.3.2-1

Each refueling outage, oil is drained from the reactor coolant pump (RCP) motor oil pots into the RCP Motor Oil Collection System. The oil in RCP Motor Oil Collection System is routed to the RCP Motor Oil Collection Tanks. The oil is then drained from the collection tanks for disposal. Sometimes during draining of the collection tanks, small amounts of water are observed in the oil. Since the oil coolers in the RCP motor oil pots are not leaking, water is probably introduced into the collection tanks through the tank vent during Reactor Building decontamination activities. An oil film on the internal surfaces of the system components may not preclude corrosion from standing water, if that should occur. Duke has no operating experience to validate that this system is experiencing corrosion, but Duke could not definitively exclude corrosion of the system components. Since water in the oil has been observed periodically and its source can not be controlled, Duke proposed the one-time RCP Motor Oil Collection System Inspection to determine if any aging is occurring in the collection tanks.

Each of the twelve collection tanks has been observed to have water in the oil at times during draining. Since none of the twelve tanks are unique by design, inspection of one tank should be indicative of the conditions in the other eleven tanks. Duke will review operating experience to determine if any of the tanks has contained water on a higher frequency in order to select the tank for inspection that is most likely to have evidence of corrosion. The collection tank chosen for inspection will be based on any higher frequency that water is observed in the oil as well as accessibility and radiological concerns.

The inspection of the lower portion of one carbon steel tank will serve to indicate the presence (or absence) of corrosion in the lower portion of the RCP Motor Oil Collection System. Component materials in the lower portion of the system include carbon steel in the tank and piping, copper alloy in the instrument tubing, and stainless steel in the tank drain valves. A visual inspection of the bottom half of the interior surface of the carbon steel tank will be performed to determine the presence of corrosion. This visual inspection will be indicative of the conditions of the copper alloys and stainless steel also exposed to this environment. Even though the corrosion mechanisms differ among carbon steel, copper alloys, and stainless steel, the copper alloys and stainless steel are, in general, more corrosion resistant to water than carbon steel and would be bounded by the inspection findings. Any indication of corrosion identified during the RCP Motor Oil Collection System Inspection will initiate the Problem Investigation Process (PIP) which will determine the need for further inspections and programmatic oversight.

SER Open Item 3.6.3.3.2-1 – As stated earlier, the staff found the program scope and parameters monitored to be acceptable. The applicant analyzes the oil samples following industry guidance; specifically, ASTM D95-83, "Water in Petroleum and Bitumens." This standard provides a widely used and accepted method of determining the amount of water in a sample of oil, but it does not provide recommendations for sampling frequency. The applicant plans to take oil samples every six months for analyses. The applicant also stated that the program will be implemented by February 6, 2013. The applicant did not provide the basis for the six month sampling interval, nor did the applicant justify delaying the implementation of the program until possibly February 6, 2013. The relatively frequent oil sampling of every six months indicates to the staff that there is a need to perform this testing on a fairly aggressive schedule. The staff requests the applicant provide the basis for the 6-month sampling interval as well as the basis for implementing the program by the end of the current operating period.

Duke Response to SER Open Item 3.6.3.3.2-1
The Keowee Oil Sampling Program is a new program for License Renewal because it has not been previously performed by Oconee Nuclear Station. The sampling activity described in the program has been performed for a number of years by Duke Energy's Hydroelectric Facility Department. The activity has historically been set up to be conducted every six months, although it has not always been performed rigorously on schedule or documented in a retrievable fashion. Since the activity is needed to manage aging for license renewal, Duke decided to bring the program under the nuclear department within Oconee control and designate it a new program. Since the frequency has historically been every six months, and the Hydroelectric Facility Department experience has shown this frequency to be acceptable, it was decided to leave that frequency unchanged. Steps have already been taken to establish this new program, such as taking the oil sample by Oconee personnel and procedure rather than by the Hydroelectric Facility Department. Although this new program, like the other new programs credited for license renewal, was originally committed in the License Renewal Application to an implementation date of February 6, 2013, Duke is now revising its commitment with respect to the timing of the implementation of this new program. The Keowee Oil Sampling Program will be implemented concurrent with the UFSAR update required by 10 CFR 50.71(e) after the Oconee renewed operating license is issued by the NRC.

SER Open Item 3.8.3.1-1 – In the discussion of the environment around the steel components in a fluid environment, Duke stated that the ONS UFSAR limits the spent fuel pool temperature to 183 °F. A review of Section 9.1.3 of the UFSAR shows a limit of 150 °F for normal heat load and abnormal heat load when the three-pump-cooler configuration is in operation. It also shows a temperature limit of 205 °F for abnormal heat loads when the two-pump-cooler configuration is in operation. From the standpoint of aging effects assessment, sustained effects under normal heat load are important. The staff requests that the applicant clarify the discrepancy between the above-noted UFSAR temperature limits. If the real normal load limit is above 150 °F, the staff is concerned that, although the temperature of 183 °F may have no effect on the steel components, it could have an aging effect on the concrete of the spent fuel pool walls and slabs. The applicable code (ACI 349) limits the concrete temperature to 150 °F. This limit of 150 °F does not guard against additional cracking. However, it assures that the concrete properties, such as compressive strength and modulus of elasticity, would not be significantly affected. The applicant should discuss the aging effects of the temperature (183 °F) on the concrete cracking and concrete properties.

Duke Response to SER Open Item 3.8.3.1-1

Normal operating temperature for the spent fuel pool is below 150 °F [Reference Oconee UFSAR Section 9.1.3.1]. Control room operators monitor spent fuel pool temperatures at all times in accordance with a periodic surveillance procedure, which is required by Improved Technical Specifications (ITS 5.4.1). Spent fuel pool normal operating temperatures range from approximately 90 °F to 120 °F. These temperatures are well below the ACI 349 threshold where degradation would occur to concrete. Therefore, there are no applicable aging effects resulting from the temperature of the spent fuel pool.

The temperature limit of 183 °F in Section 3.7.1 of Exhibit A of the Application is incorrect. Bulk spent fuel pool temperatures for the spent fuel pools remain at or below 150 °F (UFSAR Sections 9.1.3.1 and 3.8.4.4). As discussed in Section 3.8.4.4 of the Oconee UFSAR, the spent fuel pool walls were analyzed for thermal loads.

SER Open Item 3.8.3.1-2 – The discussion of the industry and ONS-specific experience database in Sections 3.7.1 and 3.7.2 of Exhibit A of the LRA does not capture (1) the essence of the results of the ONS baseline inspections that would have been performed during the implementation of the Maintenance Rule, and (2) the instances of the reported unusual events, such as the water leakage from the spent fuel pool liners. The conclusions drawn from this information could affect the applicable aging effects.

Duke Response to SER Open Item 3.8.3.1-2
Industry and Oconee specific operating experience are included in the discussion in Sections 3.7.1 and 3.7.2 of Exhibit A of the Application. More detailed information concerning the findings during the implementation of the Maintenance Rule are included in Section 4.19 of Exhibit A of the Application. Review of the findings of the Maintenance Rule inspections did not result in the identification of any aging effects other than those that were identified. Therefore, the conclusions of the Maintenance Rule civil inspections were taken into consideration during the aging effect evaluation and it was determined that the conclusions of the inspections did not change the applicable aging effects.

Note: On page 3-217 of the SER, the staff indicates that SER Open Item 3.8.3.1-2 also applies to the Intake Structure. In our response to RAI 3.7.5-2 provided by letter dated February 17, 1999, Duke provided a summary of the results of inspections of the Intake Structure.

SER Open Item 3.8.3.1.9-1 – Regarding the consideration of the applicability of the loss of material resulting from the aging effect to the ONS cable tray and conduit category, Duke determined that the aging effect applies to those cable trays and conduits located within the reactor building; however, the same aging effect is not considered plausible for cable trays and conduits located in other parts of the ONS plants (refer to Tables 3.7-1 through 3.7-6 of the LRA). Duke is requested to provide additional information to justify this differential treatment of the aging effect covering cable trays and conduits located in structures other than the reactor building.

Duke Response to SER Open Item 3.8.3.1.9-1
As stated in Section 3.7.2.2.2 of Exhibit A of the Application, cable tray is constructed of galvanized sheet metal that does not have a tendency to age with time. In addition, a review of industry experience did not identify any aging effects for cable tray systems. The staff has agreed with this conclusion in Section 3.8.3.1.2 (page 3-192) of the Oconee License Renewal SER.

A review of Oconee specific operating experience has not identified any aging effects for cable trays located in any structures except for those located in the Reactor Building. Loss of material of cable trays due to boric acid corrosion has been identified in the Reactor Building. The cable trays in the Reactor Building are located in areas that are susceptible to boric acid leakage. Therefore, loss of material due to corrosion is an applicable aging effect for the cable trays in the Reactor Buildings.

Since loss of material due to corrosion has not been identified in Oconee or industry experience for cable tray located in environments other than the Reactor Building, loss of material is not an applicable aging effect for cable tray in those locations.

SER Open Item 3.8.3.2.5-1 – ONS UFSAR Section 3.8.3.3 (related to the internal structures of the steel containment) states that the loads and load combinations considered for the design of the interior structures are described in UFSAR Section 3.8.1.3. Section 3.8.1.3 discusses the "calculated prestressing force" (after consideration of appropriate losses) as a load to be considered in load combinations tabulated in Table 3-14. Thus, the staff believes that the SSW prestressing tendons system is part of the CLB. The applicant should provide information demonstrating that the prestressing forces in the SSW will be adequately maintained for the period of extended operation.

Duke Response to SER Open Item 3.8.3.2.5-1
Loss of prestress of the SSW tendons is managed by the *Tendon – Secondary Shield Wall – Surveillance Program.* Lift-off forces are measured and compared to established acceptance criteria. Where tendon lift-off readings have fallen below the minimum allowable, adjacent tendons were tested and tendons have been re-tensioned as needed. The prestressing forces in the SSW will be adequately maintained by the *Tendon – Secondary Shield Wall – Surveillance Program* during the period of extended operation. The results of the program (minimum required prestress, lift-off testing results, retensioning, etc.) are maintained on site and are available for staff review. Information concerning the performance of the secondary shield wall (SSW) tendon system is provided in Section 4.28 of Exhibit A of the Application. In addition, response to RAIs 3.7.7-1, 4.28-1 and 4.28-2 provide additional details on the SSW tendon program.

SER Open Item 4.2.1.3-1 – With regard to the basis for the design cycles, in its response to RAI 5.3.1-1, the applicant referred to Table 5.2 of the ONS UFSAR as the basis for the 360 design cycles. However, the table also shows other normal operating design transients, such as power change cycles, power loading cycles, and 10% load increase and decrease cycles. The fatigue evaluation thus does not appear to be complete and in conformance with the design basis for the containment piping penetrations. The staff requests that the applicant justify why the thermal expansion of the RCS under these additional cycling conditions, and its effect on the steam and feedwater lines, should not be included in the fatigue assessment of the containment piping penetrations. In the UFSAR supplement, the applicant should discuss the cumulative effects of all the possible cycles in the fatigue analysis for the containment liner and penetrations for the extended period of operation.

Duke Response to SER Open Item 4.2.1.3-1
Fatigue of the liner plate and penetrations was identified as a TLAA for the extended period of operation in Section 5.3.1 of Exhibit A of the Application. The Oconee UFSAR, Section 3.8.1.5.3 identifies the fatigue loads which were considered in the design of the liner plate and penetrations. Fatigue of the liner plate and penetrations associated with the thermal load cycles of the piping systems were discussed in Section 3.8.1.5.3 of the Oconee UFSAR as restated below:

> 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.

The basis for the thermal fatigue evaluation of the liner plate and penetrations is the thermal transient cycle count assumptions from the B&W Reactor Coolant System Functional Specification. This transient cycle set can be found in Table 5-2 of the Oconee UFSAR for the Reactor Coolant system components.

The original design basis for the penetrations is the 1965 ASME Boiler and Pressure Vessel Code, Section III. An updated analysis was performed according to the rules in the 1983 ASME Boiler and Pressure Vessel Code, Section III. The analysis was performed for the applicable operating design transients listed in Table 5-2 of the Oconee UFSAR. This analysis included transients such as power change cycles, power loading cycles, and 10% load increase and decrease cycles. Although not operated this way, Oconee was originally designed as a load-follow plant. This accounts for the large number of cycles of loading and unloading from 8% to 100% power.

From a fatigue standpoint, the penetrations of concern are the main steam and main feedwater penetrations. These penetrations are subjected to the largest number of cycles and change in temperatures due to the transients listed in Table 5-2. The total effect of the transients on the

fatigue design of the main steam and main feedwater penetrations is a cumulative usage factor of 0.4, which is less than the ASME Code allowable of 1.0.

The projected number of cycles for each Oconee unit through 60 years of continued operation are bounded by the cycles listed in Table 5-2 of the Oconee UFSAR. For example, the units are designed for 18,000 cycles of Transient 3 (8% to 100% power). For the main feedwater or main steam systems to cycle 18,000 times in 60 years, the reactor would need to cycle from 8% power to 100% power 300 times a year or almost once a day. The Reactor Coolant System and associated systems would need to operate well outside current practice to accumulate one cycle of 8% power to 100% power every day.

Therefore, as provided for in Part 54, the time-limited aging analysis of the containment liner plate and penetration fatigue is resolved in accordance with Part 54.21(c)(1)(i) by demonstrating that the analysis remains valid for the period of extended operation.

The content of the UFSAR Supplement is the subject of our response to SER Open Item 3.0-1.

SER Open Item 4.2.2.3-1 – In Figures 1, 2, and 3 of Appendix 16.6-2 to Chapter 16 of the UFSAR Supplement for License Renewal, the applicant shows the PLL lines and MRVs for the 60-year period for each group of tendons in the ONS containments. However, the applicant does not show the trend lines that would demonstrate the adequacy of the existing prestressing forces in the containment tendons for the period of extended operation.

Duke Response to SER Open Item 4.2.2.3-1
Prior to 1996, Oconee conducted tendon testing on the same set of pre-selected tendons. Subsequent inspections were performed using a Regulatory Guide 1.35 type surveillance. The inspections will be implemented in the future in accordance with requirements of 10 CFR §50.55a (61 *Federal Register* 41303, dated August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants." Therefore, as provided for in Part 54, TLAA of containment tendon forces can be conducted in accordance with Part 54.21(c)(iii) by relying on the tendon surveillance program required by Part 50.55a(b)(ix).

The *Containment Inservice Inspection Plan* is discussed in Section 4.8.2 of Exhibit A of the Application with additional discussion provided in Duke responses to RAIs 4.8-3, 5.3.2-1, and 5.3.2-2 transmitted in a February 8, 1999 letter. The *Containment Inservice Inspection Plan* includes testing, evaluation, trending and reporting. The documentation of the program and trending of the loss of prestress are maintained on site and available for staff review. The attributes of an effective aging management program are provided in Section 4.8.2 and while the program addresses additional aging effects, only those attributes associated with managing loss of prestress are restated here. Minor revisions to the initial program description have been made to address staff concerns.

Purpose – The purpose of the ASME Section XI, Subsection IWL examinations is to identify and correct degradation of the post-tensioning system prior to a loss of prestress that does not meet the required minimum value.

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

Aging Effects – Loss of prestress of the post-tensioning system.

Method – Tendon prestress force and elongation are required to be measured to evaluate the prestressing force of the system. Prestress forces are trended in accordance with the requirements of 10 CFR 50.55a(b)(2)(ix)(B).

Sample Size – Not applicable for an existing program. Note: the sample size is specified in IWL-2520.

Industry Codes or Standard – ASME Code Section XI, Subsection IWL provides requirements for inservice inspection, trending, and repair or replacement activities of the post-tensioning systems of concrete containments.

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

Acceptance Criteria or Standard – Acceptance standards are specified in Oconee UFSAR, Chapter 16, SLC 16.6.2.

Corrective Action – Requirements for repair or replacement activities, including but not limited to retensioning, are specified in IWL-4000 and IWL-7000. Specific corrective actions will be taken in accordance with the *Duke Quality Assurance Program.*

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

Regulatory Basis – The Oconee *Containment Inservice Inspection Plan* will implement the requirements of 10 CFR §50.55a (61 *Federal Register* 41303, dated August 8, 1996) and the 1992 Edition with the 1992 Addenda of Subsection IWL, "Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants."

Operating experience which demonstrates the effectiveness of the *Containment Inservice Inspection Plan* applicable to the tendon force monitoring is provided in Section 4.8.2 of Exhibit A of the Application and in response to RAI 4.8-3 contained in Duke letter dated February 8, 1999.

SER Open Item 4.2.3-1 – The applicant indicated that these locations would be managed by the ONS FMP. The adequacy of this program to address the flaw evaluation TLAA cannot be determined without additional information. The applicant should provide the following information relating to the locations identified in Section 5.4.1.2 of Exhibit A of the LRA that could not be demonstrated as acceptable for the number of controlling design basis transients:

- Characterize the indications identified by the ISI for each of the locations listed (i.e., nature, length, through-wall extent and through–wall location);
- From the results of successive ISI of the same flaw locations, characterize the extent of growth of the indication(s) as indicated by the successive examinations;
- For each of the fracture mechanics analyses, identify the transient and number of cycles assumed in the analyses, and the ASME Code Section XI, IWB-3600 criteria that was not satisfied at the end of the license renewal period;
- As of January 1, 1999, what is the status of the actual number of transient cycles for each location, the plant status regarding effective-full-power-years (EFPY), and the estimated EFPY at the end of the license renewal period?
- If the transient cycle count approaches or exceeds the allowable design limit, identify the corrective action steps that could be taken.

Duke Response to SER Open Item 4.2.3-1
Section 5.4.1.2 of the license renewal application (LRA) describes time-limited-aging-analyses (TLAA) related to flaw growth acceptance for the reactor coolant system and Class 1 components at Oconee. As described in the LRA, inservice inspection (ISI) at Oconee, in accordance with ASME Section XI ISI requirements, has lead to the identification of crack-like indications, primarily in welds. The fracture mechanics analyses used for flaw acceptance through the current license period have been reviewed for acceptability for the period of extended operation. This review identified several general flaw locations that could not immediately be demonstrated to be acceptable for the number of controlling design basis transients, but which will continue to be managed by the Oconee *Thermal Fatigue Management Program.*

Since the submittal of the application in July 1998, most of the locations identified in Section 5.4.1.2 of Exhibit A of the LRA that could not be demonstrated to be acceptable have been reanalyzed and found acceptable for the number of controlling design basis transients. The following locations were not reanalyzed: flaw in the pressurizer upper head to shell weld at Unit 2, flaw in the weld that connects the OTSG upper head to tubesheet at Unit 2, and the discontinuities in the CRDM motor tube housings at Units 1 and 2. At present, the pressurizer upper head to shell weld at Unit 2 is being re-analyzed. The current design cycle limit and any revised design cycle limit resulting from reanalysis will be managed for this location by the Oconee *Thermal Fatigue Management Program.* The OTSGs at Unit 2 and CRDMs at Units 1

and 2 are in the process of being replaced, thus reanalysis was not needed. Therefore, all locations, with the exception of the flaw in the pressurizer upper head to shell weld on Unit 2, are acceptable the number of controlling design basis transients. Table 1 provides a range of updated information (i.e., controlling transients and extent of growth) associated with each of the locations.

Note that Table 1 does not contain information associated with the CRDM motor tube housing. The CRDM motor tube housing indications are described in the BAW- topical report entitled "A Study of Discontinuities in Control Rod drive Motor Tube Extensions," BAW-10047, Revision 1, August 1972. A fracture mechanics analysis, which applies to the Type A drives at Oconee Units 1 and 2, was performed to show that the CRDM motor tube extension fabrication discontinuities were acceptable for the design life of the plant. The CRDM fracture mechanics analysis will not be updated for license renewal since the Type A CRDMs at Units 1 and 2 will all be replaced with Type C drives prior to the end of the current term of operation. The Type C drives do not contain the subject fabrication discontinuities.

Table 1. Summary of Specific Oconee Fracture Mechanics Calculations of Flaw Indications

Component Flaw Location	Unit	Flaw Size Per IWA-3000			Controlling Transients	Inservice Inspection Results	Controlling design transient cycle limit for location	Total number of Transient Cycles the indication is acceptable for	Accumulated Transient Cycles when indication was observed
		a(in.)	t (in.)	l(in.)					
Pressurizer near heater bundle	1	1.075	7.0	2.15	Heatup and Cooldown	B&W first reported this indication in Outage 7 in 1983. The indication was sized at 12.33% a/t. Monitoring of the indication in three successive outages, (Outage 9 March 1986, Outage 11 February 1989 and Outage 13 September 1991) showed no increase in size.	360	448	88
Pressurizer support lugs Larger of two similar indications	1	0.7	3.5	1.35	Heatup and Cooldown	B&W first reported two unacceptable indications in Outage 6 in 1981. Fracture mechanics analysis accepted these indications. The support lug welds were reexamined in Outage 7 in 1983 and a second fracture mechanics analysis performed. The indications were acceptable. No monitoring was performed.	360	425	65
Steam generator at the upper head to tubesheet region	1	0.57	8.05	6.1	Heatup and Cooldown	B&W first reported this indication in Outage 12 in 1990. The indication was sized at 7.1% a/t. Monitoring of the indication in Outage 14, 1992 and Outage 17, 1997 showed no increase in size.	120	207	87

Table 1. Summary of Specific Oconee Fracture Mechanics Calculations of Flaw Indications

Component Flaw Location	Unit	Flaw Size Per IWA-3000 a(in.)	t (in.)	l(in.)	Controlling Transients	Inservice Inspection Results	Controlling design transient cycle limit for location	Total number of Transient Cycles the indication is acceptable for	Accumulated Transient Cycles when indication was observed
Reactor vessel at the reactor vessel flange to shell region	1	1.15	12.0	4.4	Heatup and Cooldown Inservice Leak and Hydro	B&W first reported thirteen unacceptable indications in Outage 9 in 1986. The indications were re-evaluated in 1987 and were finally resolved as geometry. No further action was taken.	Not Applicable	Not Applicable	Not Applicable
Core flood tank dump valve to nozzle Largest flaw reported is a=1.30 inches and 1.65 inches	2	1.30	2.7	1.65	Heatup and Cooldown	B&W first reported fifteen unacceptable indications in Outage 6 in 1983. Fracture mechanics analysis accepted these indications. The indications were re-sized in Outage 7 in 1985 with different transducers and consequently, twelve indications were found unacceptable. A second fracture mechanics analysis accepted these indications. Nuclear Energy Services (NES) was contracted to monitor these indications in Outage 8 in 1986. NES recorded nineteen indications of which only four were unacceptable. These four indications were correlated with the previous B&W data. Review of both sets of data show that the flaws had not increased in size.	360	455	95

Table 1. Summary of Specific Oconee Fracture Mechanics Calculations of Flaw Indications

Component Flaw Location	Unit	Flaw Size Per IWA-3000			Controlling Transients	Inservice Inspection Results	Controlling design transient cycle limit for location	Total number of Transient Cycles the indication is acceptable for	Accumulated Transient Cycles when indication was observed
		a(in.)	t (in.)	l(in.)					
Pressurizer upper head to shell region Larger of two similar indications	2	0.55	4.75	7.0	Heatup and Cooldown LOCA	B&W first reported two unacceptable indications in Outage 1 in 1976. Fracture mechanics analysis performed on the larger of the two indications shows it acceptable. Subsequent examinations in Outage 2 (1977), Outage 3 (1979) and Outage 4 (1980) show no flaw growth.	240	279	39

SER Open Item 4.2.3-2 – Since GSI–190 has not been resolved, the staff requested, in RAI 1.5.5-1, that the applicant discuss how it satisfies the relevant portion of paragraph 54.29 of the license renewal rule as discussed in the statement of considerations (SOC) (60 FR 22484, May 8, 1995) in the absence of the staff's endorsement of EPRI Report TR-105759. The applicant did not provide a technical rationale addressing the adequacy of components in the RCP boundary considering environmental fatigue effects pending the resolution of GSI–190. In its response to the RAI, the applicant stated that the concerns of GSI–190 are not directly related to the ONS thermal fatigue design and licensing basis. The applicant further indicated the application contains its technical rationale for concluding that the effects of thermal fatigue will be adequately managed for the period of extended operation or until GSI–190 is resolved. On this basis, the applicant concluded that the relevant portions of 50.29 of the license renewal rule as discussed in the statement of considerations (60 FR 22484, May 8, 1995) are met by the ONS FMP. The staff does not agree with the applicant's reasoning. As discussed above, the staff assessment for GSI–166 found that there is sufficient conservatism in the CLB for the 40–year design life. However, this conclusion could not be extrapolated beyond the current facility design life. As a consequence, the staff recommended that a sample of components with high usage factors be evaluated using the latest available environmental fatigue data for any proposed period of extended operation. The staff also initiated GSI–190 to further evaluate this issue for license renewal.

On the basis of the preceding discussion, the staff concludes that the applicant's TLAA of the RCS is not adequate to address the fatigue concerns for operation beyond the current design life of 40 years. The applicant must either develop an aging management program that incorporates a plant-specific resolution of GSI–190 or submit a technical rationale which demonstrates that the CLB will be maintained until some later point in time in the period of extended operation, at which point one or more reasonable options would be available to adequately manage the effects of aging. If GSI–190 is resolved prior to the period of extended operation, the applicant may follow the resolution of the GSI.

Duke Response to Open Item 4.2.3-2

Background

In preparing a response to SER Open Item 4.2.3-2, Duke met with the NRC staff on August 25, 1999 to discuss options associated with addressing Generic Safety Issue (GSI) 190. GSI –190 pertains to the adequacy of fatigue design life when environmental effects are considered for light water reactor components beyond a 40 year operating period. In preparation for that meeting, Duke developed a draft response to this open item. The draft of the open item response along with NRC feedback were captured in the NRC meeting summary dated September 9, 1999.

NRC feedback on the GSI-190 issue as provided in the September 9, 1999 letter is as follows:

> Open item 4.2.3-2 relates to generic safety issue (GSI) 190, "Fatigue Evaluation of Metal Components for 60–year Plant Life." The staff provided Duke with three options in its SER to resolve this issue for Oconee. The three options were: 1) develop an aging

management program that incorporates a plant-specific resolution of GSI-190, 2) submit a technical rationale which demonstrates that the current licensing basis will be maintained until some later point in time at which point one or more reasonable options would be available to adequately manage the effects of aging, or 3) If GSI-190 is resolved prior to the period of extended operation, Oconee may follow the resolution of the GSI.

Duke's proposed response followed option 2. Duke stated that it considers modification of the Oconee thermal fatigue management program to account for environmental effects on fatigue life to be a feasible option to resolve GSI-190 for Oconee. The staff stated that this option would present it difficulties in closing out the SER open item because the selection criteria for the appropriate locations and the environmental penalty factors to be applied have not been specified. Duke stated that it did not want to specify the location and penalty factors to be used at this time because of the continuing research in this area.

The staff stated that Duke could pick the locations based on NUREG/CR-6260 and the penalty factors based on guidance it had provided the Nuclear Energy Institute in an August 6, 1999, letter. The staff stated that if GSI-190 can be resolved for Oconee on a plant-specific basis then it would lead to less regulatory uncertainty regarding the issue in the future. Duke stated that it would consider the information exchanged during the meeting and determine if it will revise its proposed response to SER open item 4.2.3-2. Nevertheless, Duke will provide a formal response to SER open item 4.2.3-2 by October 15, 1999, in accordance with the Oconee LRA schedule.

Duke has determined that addressing GSI-190 based on NRC option 1 (develop an aging management program that incorporates a plant-specific resolution of GSI-190) can better satisfy the criteria to offer a technically feasible option for issue resolution with less regulatory uncertainty. Assuming the unavailability of GSI-190 resolution prior to the period of extended operation (NRC option 3), the following discussion provides the technically feasible option for managing the adequacy of fatigue design life when environmental effects are considered for certain light water reactor components beyond a 40 year operating period.

Modified Aging Management Program

The Oconee Thermal Fatigue Management Program can be modified in the future to incorporate a plant-specific resolution of GSI-190. The current Oconee Thermal Fatigue Management Program relies on cycle counting to assure compliance with the current licensing basis. This technique has been accepted by NRC in the Oconee Safety Evaluation Report in Section 4.2.3.4. Any modifications to the Oconee Thermal Fatigue Management Program to account for environmental effects on fatigue life should consider the practical and reliable aspects of cycle counting. Section 5.4.1 of the Oconee License Renewal Application provides further specifics on the Oconee design cycle basis.

Future modifications to the Oconee Thermal Fatigue Management Program will adjust the allowable design cycles limits being tracked by the program. These adjustments will involve the use of an environmental penalty factor to be applied to selected, appropriate locations. The specific Oconee locations for the application of this penalty factor are given in NUREG/CR-6260.

Section 5.3 of NUREG/CR-6260 gives the following component locations of interest in B&W plants. These component locations are applicable at Oconee. The six component locations are:

1. Reactor vessel shell and lower head
2. Reactor vessel inlet and outlet nozzles
3. Pressurizer surge line
4. Makeup/high pressure injection (HPI) nozzle
5. Reactor vessel core flood nozzle
6. Decay heat removal system Class 1 piping

Accounting for environmental effects on fatigue life requires the application of an environmental penalty factor to the design at these locations. The three locations associated with the reactor vessel (locations 1, 2, and 5) have already been assessed in association with the B&W Owners Group Topical Report, *Demonstration of the Management of Aging Effects for the Reactor Vessel*, BAW-2251A. The NRC concluded in Section 3.4.1 of their SER of this report, dated April 26, 1999, that "...B&WOG has adequately addressed GSI-190 regarding environmentally assisted fatigue of the reactor vessel components for the GLRP member plants for license renewal." This conclusion obviously includes the Oconee reactor vessels, and therefore the technical demonstration for locations 1, 2 and 5 above are already complete.

The remaining three locations in the Reactor Coolant System (locations 3, 4, and 6) are constructed of stainless steel piping. An environmental penalty factor will be applied at these three locations. Current industry thinking is that this penalty is to be applied to incremental usage factor values determined during design analysis. An environmental penalty factor similar to the F_{en} factor taken from Reference 1 may be appropriate. The term F_{en} is defined as the ratio between the fatigue life in air at room temperature to that in water at the reactor fluid temperature. It may be a function of several variables, including material, oxygen content of the water, strain rate, and temperature. Actual application of a penalty factor like F_{en} would aalso take into consideration the latest and most appropriate industry correlation for such a factor.

Calculating the effective environmental penalty factor, F_{en}, begins by calculating a nominal environmental penalty factor, $F_{en,nom}$ to which will be applied another material-specific variable in order to derive F_{en}.

$$F_{en,nom} = \exp\,[0.935 - T^{*}O^{*}\varepsilon'^{*}]$$

Though the scientific basis for the values of the variables in this equation is still under development, the variables are:

O^* = Transformed oxygen content
T^* = Transformed temperature
ε'^* = Transformed strain rate

The effective environmental fatigue penalty factor, F_{en}, is obtained by dividing the nominal value with a material-specific factor which accounts for moderate environmental fatigue effects already included in the S-N curves of Figures I-9.1 and I-9.2 of ASME Section III.

$$F_{en} = F_{en,nom} / Z, \text{ but no less than } 1.0$$

Where, Z = 1.5 for wrought and cast stainless steels like the components in locations 3, 4 and 6.

To modify the Thermal Fatigue Management Program, an effective environmental penalty factor, F_{en}, would be individually determined and applied to each of the original incremental usage factors, U_i, (for specific, applicable transients) for the selected locations. The resulting revised set of incremental usage factors for a location are then summed to determine a revised, environmentally penalized cumulative usage factor (CUF_{en}). The limits on CUF_{en} would remain defined by ASME Section III to be less than or equal 1.0.

$$CUF_{en} = U_1 \bullet F_{en,1} + U_2 \bullet F_{en,2} + U_3 \bullet F_{en,3} \ldots\ U_i \bullet F_{en,i} \ldots. + U_n \bullet F_{en,n}$$

Should the CUF_{en} for a location exceed the Code-allowable value of 1.0, modifications can be made within the calculation of each incremental usage factor value to adjust the overall CUF_{en}. Since, in the analysis basis, a piecewise linear relationship exists between design cycles and the incremental usage factors, adjustments in the incremental usage factors can be obtained by making adjustments in the number of allowable design cycles applicable to each given transient. The relationship between design cycles and incremental usage factor is considered piecewise linear because each stress range pair associated with a given transient produces its own linear rate. When pieced together these sets of stress range pairs sum to an incremental usage value at an allowable number of design cycles for that transient. The sum of all of the incremental usage factors for all of the transients will equal the cumulative usage factor at the adjusted number of design occurrences of all of the transients.

Appropriately modifying the number of allowable design transients until the CUF_{en} is equal to or less than 1.0 will bring the location back within the parameters of the design code. A further review of the lowest number of acceptable cycles for a given transient for all component locations will determine the limiting value that should then be tracked by the Thermal Fatigue Management Program. In this manner, the program can continue to confirm a valid design by managing transient cycle counts. Modifying the Oconee Thermal Fatigue Management Program in this manner to account for environmental effects on fatigue life is a feasible option to resolve GSI-190 for Oconee.

Reference 1:
Mehta, H.S. Recommended Approach to Implement Environmental Fatigue Procedures in ASME Code, Revision 2, August 29, 1999. Currently under review by the Pressure Vessel Research Council, Steering Committee on Cyclic Life & Environmental Effects.

SER Open Item 4.2.5.3-1 – The TLAA described as "reduction in fracture toughness" is related to the acceptability of the reactor vessel internals under loss-of-coolant-accident (LOCA) and seismic loading. BAW-2248 states that Appendix E to BAW-10008,Part 1, Revision 1, "Reactor Internals Stress & Deflection Due to LOCA & Max Hypothetical Earthquake," concludes "that at the end of 40 years, the internals will have adequate ductility to absorb local strain at the regions of maximum stress intensity, and that irradiation will not adversely affect deformation limits." BAW-2248 also states that this TLAA will be resolved on a plant-specific basis per 10 CFR 54.21 (c)(1)(iii) based on the results and conclusion of the planned RVIAMP. Section 5.4.3 of Exhibit A of the LRA states that the RVIAMP will assure that appropriate action will be taken in a timely manner to assure continued validity of the design of the ONS reactor vessel internals. Plant-specific analysis is required to demonstrate that, under LOCA and seismic loading and with irradiation accumulated at the expiration of the period of extended operation, the internals have adequate ductility to absorb local strain at the regions of maximum stress intensity and will meet the deformation limits. The applicant must provide a plan to develop data to demonstrate that the internals will meet the deformation limits through the period of extended operation. The plan must be submitted for staff review and approval.

Duke Response to SER Open Item 4.2.5.3-1

The development of the data to demonstrate that the reactor vessel internals will have adequate ductility to absorb local strain at the regions of high stress intensity and will meet the deformation limits at the end of the period of extended operation will be accomplished as a part of the Oconee *Reactor Vessel Internals Aging Management Program.* This program will prepare the analyses needed to determine that the Reactor Vessel Internals remain functional during the period of extended operation. Current plans are to complete these analyses at least three years prior to the outages in which inspections are to be performed. Following issuance of the renewed operating licenses for Oconee Nuclear Station, these inspections will be performed during the 4th 10-year inservice inspection interval of the Oconee unit being inspected.

SER Open Item 4.2.5.3-2 – BAW-2248 also identifies a fourth TLAA regarding flaw growth acceptance in accordance with the ASME B&PV Code, Section XI ISI requirements. This TLAA is identified in the topical report as requiring a plant-specific evaluation, and as such is not evaluated in the topical report. The applicant does not address the applicability of this flaw growth TLAA to ONS.

Duke Response to SER Open Item 4.2.5.3-2
Section 5.4.1.2 of Exhibit A of the Application discusses this TLAA. Based upon our review of ISI records, no flaws in the Reactor Vessel Internals have been identified. Thus, no flaw growth evaluation needs to be performed for Oconee. Also see page 4-11 of the Oconee SER dated June 16, 1999 for the evaluation of this topic.

Attachment 3

Responses to Safety Evaluation Report
Confirmatory Items

October 15, 1999

Note: The following introduction is provided at the beginning of Section 1.5 of the SER –

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

SER Confirmatory Item 2.2.3.6.9-1 – On June 2, 1999, the staff and the applicant held two conference calls to clarify the applicant's position on documenting pipe segments that provide structural support. In a memorandum dated June 2, 1999, the staff documented the conclusion from the conference calls. As documented in the June 2, 1999, memorandum, the applicant stated that all SR/NSR interface valves for Oconee piping classes B, C, and F included piping segments and anchorages beyond the SR/NSR interface boundary valve that ensured the integrity of the boundary valve under all design basis loadings. The applicant stated that these components were included within the scope of license renewal and subject to aging management review. The applicant further clarified that Oconee piping class A does not interface with non-safety-related piping and, therefore, does not have any piping segments or anchorages that support SR/NSR boundary valves. Likewise, Oconee class D piping is NSR and is included within the scope of license renewal only to ensure its failure during a design-basis event does not affect the capability of adjacent safety-related equipment to perform its intended function. Therefore, class D piping included in the scope of license renewal for this reason will not have any SR/NSR interfaces requiring piping segments that provide structural support to boundary points.

The applicant committed to document the information from the two conference calls, regarding the status of piping segments that provide structural support to boundary points, in a letter to the staff.

Duke Response to SER Confirmatory Item 2.2.3.6.9-1
For Oconee, the portions of piping between the boundary of the safety-related piping (e.g., valve, orifice) and nonsafety-related piping and the first seismic anchors (or equivalent) beyond the boundary are within the scope of license renewal and subject to an aging management review. These piping segments beyond the safety-related/nonsafety-related boundaries perform the intended function of providing structural integrity under all current licensing basis design loading conditions for safety-related components within the scope of license renewal. For Oconee Class B, C, and F, all piping between the boundary of the safety-related piping and nonsafety-related piping and the first seismic anchors (or equivalent) beyond the boundary are within the scope of

license renewal and subject to an aging management review. Class A and D piping systems do not have these safety/nonsafety interfaces. Class A piping connects to either Class B or C piping, which is safety-related. Class D piping is nonsafety piping which is qualified for seismic or II/I issues.

The applicable aging effects for the piping segments beyond the safety-related/nonsafety-related boundary are the same as those in their respective fluid systems. The aging management programs credited in these systems for managing the applicable aging effects also apply to the piping segments between the safety-related/nonsafety-related boundary up to the first seismic anchors (or equivalent) beyond the boundary.

The seismic anchors (or equivalent) supporting these piping segments beyond the safety-related/nonsafety-related boundary are within the scope of license renewal as noted in Section 2.7.2.2.1 of the Application. The aging management review for these seismic anchors (or equivalent) is presented in Section 3.7 of the Application.

SER Confirmatory Item 3.5.3.2-1 – The reactor building spray system inspection does not mention the nitrogen purge and blanketing system, yet the applicant takes credit for this aging management program in Section 3.5.4 of the LRA. The staff requested the applicant discuss how the inspection of the reactor building spray system manages aging effects for the nitrogen purge and blanketing system. Duke responded to the staff's question in a telephone conversation as documented in a phone call summary dated June 2, 1999. The applicant stated that the some stainless steel components in the nitrogen purge and blanket system are also exposed to alternate wetting and drying with borated water that could lead to cracking or loss of material. Because the materials and environments are the same for both systems, Duke determined inspections in both systems was not necessary. The applicant also stated that the results of the reactor building spray system inspection bound the components of the nitrogen purge and blanket system. Both systems have stainless steel components alternately wetted and dried with borated water. Where the susceptible components are located in the reactor building spray system, they are exposed to an oxygenated environment in combination with borated water. The nitrogen purge and blanket system components are expose to nitrogen gas in combination with borated water. Because the oxygenated environment is more corrosive than nitrogen gas, the inspection of the reactor building spray system components is more likely to identify the existence of these applicable aging effects and thus, the inspection of the reactor building spray system components would bound the inspection of the nitrogen purge and blanket system components. The staff requests the applicant formally submit its response to this program scope question.

Duke Response to SER Confirmatory Item 3.5.3.2-1
The Reactor Building Spray System Inspection will perform an examination of stainless steel components subject to alternate wetting and drying with borated water that could lead to cracking or loss of material. The inspection is to determine if cracking or loss of material is occurring due to alternate wetting and drying. Some stainless steel components in the Nitrogen Purge and Blanket System are also exposed to alternate wetting and drying with borated water that could lead to cracking or loss of material. Since the materials and environments are the same, inspection in both systems was determined not to be necessary. The results of the Reactor Building Spray System Inspection will be applied to the components in the Nitrogen Purge and Blanket System exposed to alternate wetting and drying.

The results of the Reactor Building Spray System Inspection bound the components of the Nitrogen Purge and Blanket System. As noted earlier, both systems have stainless steel components alternately wetted and dried with borated water. Where the susceptible components are located in the Reactor Building Spray System, they are exposed to an oxygenated environment in combination with borated water. The Nitrogen Purge and Blanket System components are expose to nitrogen gas in combination with borated water. Since the oxygenated environment is more corrosive than nitrogen gas, the inspection of the Reactor Building Spray System components is more likely to identify the existence of these applicable aging effects. As a result, the inspection of the Reactor Building Spray System components would bound the inspection of the Nitrogen Purge and Blanket System components.

SER Confirmatory Item 3.6.1.3.2-1 – As stated earlier, the staff found the program scope and parameters monitored to be acceptable. The applicant stated that the frequency of performance testing varies by system—ranging from quarterly to every third refueling outage. The auxiliary service water system is visually inspected every 5 years. As documented in a phone call summary dated June 2, 1999, the applicant provided a discussion of operating experience that demonstrates these frequencies can be relied upon to detect aging effects before there is a loss of component intended function. The applicant stated this testing has been performed at Oconee for at least ten years, and some of the testing has been performed since initial operation. Duke has incorporated operating experience into its testing activities, as needed, as part of its corrective action program. The staff concludes the frequency of the testing activity is supported by operating experience to date. The staff concludes the adequate program scope, acceptable monitoring parameters and testing frequency may be relied upon to detect aging effects before there is a loss of component intended function. The staff requests the applicant formally document its response to this question related to operating experience.

Duke Response to SER Confirmatory Item 3.6.1.3.2-1

All of the system performance testing activities have been performed for at least ten years, with some of the testing activities having been performed since initial operation of Oconee, the Standby Shutdown Facility, and Keowee. Many of these testing activities were credited in response to Generic Letter 89-13. As with other programs, any indication of the applicable aging effects identified during the system performance testing activities will initiate the Problem Investigation Process. Performance testing has proven an effective method of managing fouling in service water systems. A decreasing trend in flow rates has resulted in piping replacements in several locations, including portions of small diameter piping in the Low Pressure Service Water System and larger bore piping in the SSF Auxiliary Service Water System.

SER Confirmatory Item 3.6.3.3.2-1 – The applicant implements corrective actions if the oil samples contain greater than 0.1 percent water by volume. As documented in a phone call summary dated June 2, 1999, the applicant provided to the staff the basis for this acceptance criteria. Duke stated that its operating experience at its hydro facilities established a 0.1 percent water by volume as the corrective action limit. The applicant also stated that EPRI document NP-4916, "Lubrication Guide," Revision 2 (which documents the latest industry guidance in this area) recommends a limit of 0.2 percent water by volume. Duke continues to use the more conservative limit of 0.1 percent water by volume and credits it as the corrective action limit. The staff concludes the applicant provided a reasonable and conservative basis for its acceptance criteria for this program. In view of the importance of Keowee as an emergency power source, the staff requests the applicant formally document its response to this question.

Duke Response to SER Confirmatory Item 3.6.3.3.2-1
Duke hydroelectric station operating experience established 0.1 percent water by volume as the corrective action limit. By comparison, EPRI document NP-4916, Lubrication Guide, Revision 2 which documents the latest industry guidance in this area recommends a limit of 0.2 percent water by volume. Duke continues to use the more conservative limit of 0.1 percent water by volume and credits it as the corrective action limit.

SER Confirmatory Item 4.2.1.3-1 – In the applicant's initial response to RAI 3.3-6, Duke revised a paragraph related to the effects of periodic Type A leak rate tests on the TLAA. Duke stated that seven Type A tests have been performed, and based on the revised frequency of Type A tests (according to Option B of 10 CFR Part 50, Appendix J), four more tests will be performed. The applicant should note that the performance-based Option B allows the 10 year frequency if the results of the earlier tests have not shown problems. Also, the applicant may have to perform additional pressure tests after major modifications or repairs to the containment pressure boundary (e.g., steam generator replacement). The staff recognizes that these additional considerations will not affect the conclusions of the applicant's TLAA evaluation; however, for the completeness of the UFSAR supplement, the applicant should address these considerations in the analysis.

Duke Response to SER Confirmatory Item 4.2.1.3-1
The NRC staff issued RAI 3.3-6 in their letter dated November 14, 1997. The RAI requested additional information on the periodic Type A Integrated Leak Rate tests as part of the design loads considered in the liner plate fatigue analysis. In response to this RAI, Duke revised the final paragraph in Section 5.3.1 of Exhibit A of the Application (See Footnote 9). The final paragraph in UFSAR Supplement Section 3.8.1.5.3 of Exhibit B of the Application was also revised accordingly.

Confirmatory Item 4.2.1.3-1 identified additional considerations associated with the Type A tests that should be included in the UFSAR supplement to provide completeness. The final paragraph of the UFSAR supplement Section 3.8.1.5.3 will be revised as follows (revised text is underlined for emphasis):

Periodic Type A Integrated Leak rate tests are additional major sources of load changes. These Type A loads are considered within the set of design loads whose cumulative total was assumed to be 500 cycles. Seven Type A tests have been performed per unit to date (June 1998). <u>Based on the frequency of Type A tests (according to performance-based Option B of 10 CFR Part 50, Appendix J), four more tests may be performed per unit through the period of extended operation if the results of earlier tests have not shown problems. Additional Type A tests may be performed if major modifications or repairs are made to the containment pressure boundary.</u> The additional load cycles on the liner due to Type A testing are considered to be insignificant.

SER Confirmatory Item 4.2.3-1 – The applicant indicated that plant operating thermal transient data were used to project when plant operation would cause the number of cycles specified in the UFSAR to be exceeded. According to the applicant, locations such as the reactor vessel studs, the pressurizer spray line for Unit 3, and the emergency feedwater (EFW) system nozzle for Unit 3 required further evaluation. The applicant further indicated that the transients would be monitored by the ONS thermal FMP. The staff, in RAI 5.4.1-2, requested that the applicant describe the planned evaluation of these components and provide a schedule for the completion of these evaluations. The applicant indicated that the RPV studs were reevaluated to remove a conservative assumption regarding the number of cycles assumed in the evaluation. The Unit 3 pressurizer spray and EFW nozzles were reanalyzed because the analyses were not consistent with the Unit 1 and 2 analyses. According to the applicant, the evaluations of the RPV studs and the Unit 3 pressurizer spray line are complete, and the EFW nozzle analysis is expected to be completed by August 1, 1999. Completion of the EFW nozzle analysis and modification of the FMP as appropriate is part of Confirmatory Item 4.2.3-1.

According to the applicant, the attached piping was originally designed to USAS B31.7, Class I standards, except for the piping analysis, which was done to Class II standards. However, the ONS UFSAR indicates that the attached piping to the first isolation valve is designed to Class I standards. The staff raised a concern regarding the lack of a Class I analysis of the attached piping during a 1994 site visit. In response to the staff concern, the applicant committed to complete a Class I analysis of the attached piping to the first isolation valve by August 31, 1999. The applicant also indicated that these components would be added to the FMP. Completion of the analysis of these lines and modification of the FMP as appropriate is part of Confirmatory Item 4.2.3-1.

The applicant discussed its actions to resolve NRC Bulletin 88-08 in Section 5.4.1.1.5 of Exhibit A of the LRA. In NRC Bulletin 88-08, the staff requested that licensees review their RCS designs to identify any connected, unisolable sections of pipe that could be subjected to temperature distributions which would result in unacceptable stresses. In response to the bulletin, the applicant identified the emergency injection lines of the HPI system as the only lines potentially susceptible to unacceptable stresses. The applicant described its actions in response to the bulletin in a December 29, 1989, letter to the NRC. As a result of a subsequent leak in the normal injection line, the applicant committed to provide a revised response to NRC Bulletin 88-08 by July 1, 2000. Completion of this analysis and modification of the FMP as appropriate is part of Confirmatory Item 4.2.3-1.

Duke Response to SER Confirmatory Item 4.2.3-1

The three activities described in SER Confirmatory Item 4.2.3-1 are associated with the ongoing revision of design fatigue analyses associated with the EFW nozzle, several RCS branch line locations and analyses associated with an update to NRC Bulletin 88-08. These activities involve the review and updating of design calculations and do not change or modify in any way the Thermal Fatigue Management Program credited for license renewal. Updating these design calculations only serves to validate or revise the thermal cycle count assumptions that are applicable for a particular location. Details on the structure of the Oconee Thermal Fatigue Management Program are described in our letter dated March 29, 1999.

Specifically, the EFW nozzle analysis has been completed. Thermal cycle count assumptions were revalidated for the EFW nozzles on all three units. The revised cycle count assumptions have been incorporated into the basis of the Oconee Thermal Fatigue Management Program for this location.

The RCS branch line reanalysis to upgrade to a Class I analysis for each appropriate branch line location has been completed. Each branch line location has been reanalyzed by considering the appropriate design transient values and thermal cycle count assumptions on all three units. The cycle count assumptions have been incorporated into the basis of the Oconee Thermal Fatigue Management Program for these locations.

The activity associated with NRC Bulletin 88-08 is intended to provide confirmation that existing analyses are valid by comparing actual thermal data with the assumed values used in the existing analyses. Because of the conservatism of these assumed values and actual data obtained from Unit 1, Duke fully expects that the existing analyses will remain valid. Additional thermal data is being obtained on Units 2 and 3, and resolution of the current licensing commitment is proceeding toward July 1, 2000. (This commitment is currently captured within the Oconee commitment management program.) Regardless of the results of this activity, no changes will occur to the structure of the Oconee Thermal Fatigue Management Program committed for license renewal. As in the two previous examples, the activity associated with NRC Bulletin 88-08 will serve to update the design basis underlying the program.

Attachment 4

Commitments

October 15, 1999

Commitments

Note: Commitments are docketed statements that establish requirements or actions to be performed.

1. A revision to the UFSAR Supplement will be made to incorporate an appropriate description of the *Chilled Water Refrigeration Unit Preventive Maintenance Activity.* (SER Open Item 2.2.3.4.3.2.1-1)

2. The UFSAR Supplement description of the *Cast Iron Selective Leaching Inspection* will be revised to include the Chilled Water System and Condenser Circulating Water System within scope. (SER Open Item 2.2.3.4.3.2.1-1)

3. The UFSAR Supplement description of the *Treated Water Systems Stainless Steel Inspection* will be revised to include the Chilled Water System within scope. (SER Open Item 2.2.3.4.3.2.1-1)

4. A revision to the UFSAR Supplement will be made to incorporate an appropriate description of the *Control Room Ventilation System Examination.* (SER Open Item 2.2.3.4.3.2.1-2)

5. A revision to the UFSAR Supplement will be made to incorporate an appropriate description of the *Jacket Water Heat Exchanger Preventive Maintenance Activity.* (SER Open Item 2.2.3.4.8.2.1-1)

6. Duke agrees that the resolution of the information that needs to be added to the UFSAR will be addressed after the other open and confirmatory items are resolved and prior to the issuance of the renewed operating licenses for Oconee. (SER Open Item 3.0-1)

7. For each applicable credited aging management program, the corrective action statement contained in the USFAR Supplement will be revised to state that the Problem Investigation Process applies to all structures and components within the scope of the specific program. (SER Open Item 3.2.3.3-1)

8. A revision to the UFSAR Supplement will be made to incorporate an appropriate description of the *SSF HVAC Coolers Preventive Maintenance Activity.* (SER Open Item 3.2.12-1)

9. The *Service Water Piping Corrosion Program* will be enhanced as described in the response to this SER Open Item. (SER Open 3.2.13-1)

10. The Unit 1 heater bundle inspection description contained in the UFSAR Supplement will be revised to include inspections of the heater sheath-to-heater sleeve structural weld and the heater sleeve-to-heater bundle diaphragm plate structural weld (Reference Figure 2-8 of BAW-2244A). Inspections of Unit 2 or Unit 3 heater bundle welds are not required. (SER Open Item 3.4.3.3-2)

11. A revision to the UFSAR Supplement will be made to incorporate appropriate an description of the *Reactor Vessel Internals Aging Management Program.* (SER Open Items3.4.3.3-3, 3.4.3.3-4, 3.4.3.3-5, 3.4.3.3-6, and 4.2.5.3-1.

12. The RCP oil collection tank chosen for inspection will be based on any higher frequency that water is observed in the oil as well as accessibility and radiological concerns. (SER Open Item 3.6.2.3.2-1)

13. The Keowee Oil Sampling Program will be implemented concurrent with the UFSAR update required by 10 CFR 50.71(e) after the Oconee renewed operating license is issued by the NRC. (SER Open Item 3.6.3.3.2-1)

14. A revision to the UFSAR Supplement will be made to incorporate the response to this confirmatory item. (Confirmatory Item 4.2.1.3-1)