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SUBJECT: Forwards responses to NRC 981029 requests for addl info re sections 3.4.11,3.5.9,4.3.2,4.3.8,4.6.2,4.6.3,4.6.4,4.21 & 5.7.1 of 980706 application.

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December 14, 1998

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

Subject: License Renewal
Response to Requests for Additional Information
Oconee Nuclear Station
Docket Nos. 50-269, -270, -287

By letter dated July 6, 1998, Duke Energy Corporation submitted an Application for Renewed Operating Licenses for Oconee Nuclear Station, Units 1, 2, and 3 (Application). Exhibit A of the Application contains the technical information required by 10 CFR Part 54.

By letter dated October 29, 1998, the NRC staff identified areas where additional information is needed to complete its review of the following sections of the Application: 3.4.11, 3.5.9, 4.3.2, 4.3.8, 4.6.2, 4.6.3, 4.6.4, 4.21, and 5.7.1. Attachment 1 provides our responses to the staff requests for additional information concerning these sections of the Application. Some of these responses contain new commitments or modify commitments previously made in the Application. These commitments are restated in Attachment 2 to facilitate tracking and management.

If there are any questions, please contact Bob Gill at 704-382-3339.

Very Truly Yours,

W. R. McCollum Jr.

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ATTACHMENT 1

Oconee Nuclear Station

Application for Renewed Operating Licenses

Responses to NRC Requests for Additional Information (RAI)

NRC Letter Dated October 29, 1998

Set #01

Exhibit A, Section 3.4.11, Class 1 Component Supports

RAI 3.4.11-1
What action did you take in response to Generic Letter 91-17, Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants?"

Response to RAI 3.4.11-1
Generic Letter 91-17 provided licensees with information regarding the resolution of Generic Safety Issue (GSI) 29, which addressed degradation of safety-related bolts, studs, embedments, machine caps screws, other special threaded fasteners, and all their associated nuts and washers. The technical basis for the resolution of GSI 29, as documented in NUREG-1339, includes plant-specific actions taken in response to selected NRC generic communications and industry initiatives regarding bolting maintenance procedures. The focus of the safety issue with respect to component supports was degradation or failure of supports and embedment bolting caused by stress corrosion cracking. Stress corrosion cracking of bolting in Class 1 component supports is addressed in Section 4.18.3 of Exhibit A of the Application. Generic Letter 91-17 did not require any specific action or written response.

RAI 3.4.11-2
Based on the staff's experience, degradation of bolted connections (e.g., loose bolts) potentially caused by vibration loading, is a common type of aging effect of component supports with bolted connections. Clarify whether this loading effect has been considered in the aging review for the Class 1 component supports, and (if this effect is excluded) provide the basis for excluding this effect.

Response to RAI 3.4.11-2
Vibrational loading effects have not been considered in the aging review for the Class 1 component supports. Vibrational effects on the Oconee Class 1 component supports has been addressed by the design and construction of the bolted connections.

From design experience discussed in *An Introduction to the Design and Behavior of Bolted Joints*, self-loosening of bolted connections will occur only if two essential conditions are present: cyclic, transverse loads (vibration) and relative slip between thread and/or joint surfaces [Reference Bickford, John H., *An Introduction to the Design and Behavior of Bolted Joints*, Marcel Dekker, Inc., New York, New York, 1995]. The simplest way to preclude self-loosening is to prevent loss of preload in the bolt. High preload or bolt tension creates frictional forces that discourage relative slip between the thread and/or joint surfaces. Where bolted connections are subjected to vibrational loads, proper design considers the amount of bolt preload required to preclude slip when specifying bolting materials and bolt

torque requirements. Oconee design considered adequate preload of bolted connections. Bolting materials and torque were specified to assure design requirements were met, including consideration of vibrational loads.

A review of industry (i.e., NPRDS data and NRC generic communications) and Oconee operating experience indicates that the bolted connections used in Class 1 component supports have not been subject to self-loosening by vibration. In addition, Generic Safety Issue (GSI) 29, "Bolting Degradation or Failure in Nuclear Power Plants," which addressed degradation of safety-related component support bolting, did not identify self-loosening by vibration as a safety issue. Self-loosening by vibration is not an applicable aging effect for Oconee Class 1 component supports since proper design has eliminated or compensated for its occurrence.

RAI 3.4.11-3

Table 3.4-1 does not identify any applicable aging effects for the reactor coolant pump motor vertical and lateral support assemblies due to loading from rotating/reciprocating machinery. However, the loss of preload due to rotating/reciprocating machinery has been identified as a potentially applicable aging effect for component supports and, in particular, for the reactor coolant pump motor vertical and lateral support assemblies. Identify the specific location in the license renewal application (LRA) that the loss of preload and the related aging management program(s), and demonstration are discussed, or provide a technical justification for not identifying loss of preload due to rotating/reciprocating machinery as an applicable aging effect for reactor coolant pump motor vertical and lateral support assemblies.

Response to RAI 3.4.11-3

As discussed in the Response to RAI 3.4.11-2, loss of preload in bolted connections could result in self-loosening. Loss of preload is not an applicable aging effect since proper design has eliminated or compensated for its occurrence. As evidence, no degradation of Class 1 component support bolted connections due to loss of preload from vibratory loads has been identified in the industry data.

RAI 3.4.11-4

Are there any parts of Class 1 component supports described in Section 3.4.11 that are inaccessible for inspection? If so, describe what aging management program will be relied upon to maintain the integrity of inaccessible areas. If the aging management program for inaccessible areas relies on an evaluation of the acceptability of conditions in surrounding accessible areas, please provide information to show that conditions that exist in accessible areas reasonably reflect those conditions that are likely to exist in inaccessible areas. If

different aging effects or aging management techniques are needed for inaccessible areas, please provide a summary of your actions to address the following elements concerning inaccessible areas: (1) preventive actions that will mitigate or prevent aging degradation; (2) parameters monitored or inspected relative to degradation of specific structure and component intended functions; (3) detection of aging effects before loss of structure and component intended functions; (4) monitoring, trending, inspection, testing frequency, and sample size to ensure timely detection of aging effects and corrective actions; (5) acceptance criteria to ensure fulfillment of structure and component intended functions; and (6) operating experience that provides objective evidence to demonstrate that the effects of aging will be adequately managed.

Response to RAI 3.4.11-4

As described in Section 3.4.11 of Exhibit A of the Application, Class 1 component supports include Reactor Coolant System piping supports and LOCA restraints, pressurizer support plate and support frame assemblies, reactor vessel support skirt and control rod drive service structure, Once-Through-Steam-Generator skirt and upper lateral supports, and Reactor Coolant Pump lateral and vertical support assemblies. All Class 1 component supports are accessible, as required, in order to perform appropriate inspections. Review of the current Oconee ISI program confirmed that no relief requests have been submitted for inspection of Class 1 component supports due to limited accessibility.

RAI 3.4.11-5

Table 3.4-1 indicated that the potential aging effect of cracking of lubrite pads for the once-through steam generator (OTSG) upper lateral support structure will be managed by the OTSG lateral support inspection program. Section 4.3.6 indicated that the subject inspection program is a one time inspection and it will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). It is also stated that lubrite pads that are found cracked will be replaced with new pads. Provide the basis for not performing periodic inspections to track any future potential pad cracking due to radiation effects during the period of extended operation. If applicable, please include a discussion of how the plant operating and maintenance history support this conclusion.

Response to RAI 3.4.11-5

Change in material properties of the lubrite pads has been identified as an applicable aging effect for the OTSG upper lateral support structures in Table 3.4-1 of Exhibit A of the Application. Change in material properties of the lubrite pads could degrade the surfaces of the pads, leading to less functional service by the supports. Degradation or even loss of the pad surface would not defeat the intended function of the OTSG upper lateral support structure. If the lubrite surfaces were degraded, the underlying bronze on the support could be exposed to the carbon steel bearing plate of the OTSG. Axial and radial growth of the

OTSG would not be restricted because the coefficient of friction of the bronze is similar to that of the lubrite. The OTSG upper lateral supports would be able to perform their intended function (i.e., to provide support during seismic events or to transmit pipe rupture forces and dynamic forces to the secondary shield wall) even if the surface of the lubrite pads were in a degraded condition. No plant operating or maintenance history has identified degradation of the lubrite pads. A one-time inspection at or near the end of the current term of operation is sufficient to assess the condition of the lubrite pads. Periodic inspections are not necessary during the period of extended operation because the intended function of the OTSG upper lateral supports would be maintained with the lubrite pads in a degraded condition.

RAI 3.4.11-6

Are there any Class 1 component supports described in Section 3.4.11 containing pins, springs, or sliding plates? If so, provide the basis for excluding mechanical wear as a potential aging effect for those component supports.

Response to RAI 3.4.11-6

Class 1 component supports include Reactor Coolant System piping supports and LOCA restraints, pressurizer support plate and support frame assemblies, reactor vessel support skirt and control rod drive service structure, Once-Through-Steam-Generator (OTSG) skirt and upper lateral supports, and Reactor Coolant Pump lateral and vertical support assemblies. Pins are used to connect the snubbers and the turnbuckles to the Reactor Coolant Pumps and the secondary shield wall as described in Section 2.4.11.6 of Exhibit A of the Application. Spring hangers are used for the Reactor Coolant Pump vertical support assemblies and selected Class 1 piping supports as described in Sections 2.4.11.6 and 2.7.2.2. Sliding surfaces are used on the OTSG upper lateral supports, which are described in Section 2.4.11.5.

Loss of material due to mechanical wear is not an applicable aging effect for springs and pins of the Class 1 component supports. Mechanical wear under normal conditions could be caused by vibration and thermal growth. Vibrations due to rotating/reciprocating machinery and thermal loads are considered in the design for the Class 1 component supports. Industry and Oconee operating experience have not identified mechanical wear of the springs and pins. Therefore, mechanical wear is not an applicable aging effect for these pins and springs.

If the lubrite surfaces were degraded, the underlying bronze would be exposed to the carbon steel bearing plate of the OTSG. As discussed in Response to RAI 3.4.11-5, axial and radial growth of the OTSG would not be restricted. The OTSG upper lateral supports would be able to perform their intended function (i.e., to provide support during seismic events or to transmit pipe rupture forces and dynamic forces to the secondary shield wall) even if the

surface of the lubrite pads were in a degraded condition. No plant operating or maintenance history has identified degradation of the lubrite pads of Class 1 component supports. The condition of the lubrite pads will be assessed by a one-time inspection of the upper lateral supports as discussed in Section 4.3.6 of Exhibit A of the Application.

RAI 3.4.11-7

Section 3.4.3.4 indicated that there was an instance of cracking of a weld in a drain line off the pressurizer surge line. It further stated that the root cause of the weld cracking was determined to have been a combination of stress corrosion and mechanical vibration. Provide a summary description of the subsequent corrective actions to prevent the mechanical vibration for the subject piping systems, as well as their associated supports, that may be affected by mechanical vibration. Also, indicate if these corrective actions are applicable to the period of extended operation. If not, provide the basis for your determination.

Response to RAI 3.4.11-7

The complete failure scenario of the subject weld in the drain line off the pressurizer surge line is crack initiation by stress corrosion cracking and propagation by a mixed-mode of stress corrosion cracking and vibrational fatigue. The initiator of the event was the stress corrosion cracking. A fracture mechanics analysis of the welded connection that included a surface flaw equivalent to those stipulated in Section XI of ASME Code and vibration stress based on the observed displacement of the piping, determined that the total stresses fall well below the endurance limit of the stainless steel. Therefore, the vibration in and of itself would not cause the failure. The analysis results revealed that no physical configuration changes were required to address the issue. The piping configuration was reinstalled according to the original design, and no corrective actions were required to mitigate any mechanical vibration effects. The reinstalled configuration is adequate for the period of extended operation.

Exhibit A, Section 3.5.9, Steam and Power Conversion Systems

RAI 3.5.9-1
The steam and power conversion system comprises four systems with components made of materials which may undergo degradation by different types of corrosion mechanisms when exposed during plant operation to the environments of raw or treated water. Your aging management program is designed to control this degradation by (a) controlling the relevant conditions that would lead to the onset and propagation of these aging effects and (b) by performing inspections and analyses verifying the integrity of the piping systems. Describe these inspections and analyses and show how they will permit you to evaluate integrity of the piping and other components in the steam and power conversion system.

Response to RAI 3.5.9-1
The four systems that comprise the steam and power conversion systems are the Main Steam, Condensate, Emergency Feedwater, and Feedwater Systems. The Chemistry Control Program controls the relevant conditions that would lead to the onset and propagation of some of these aging effects in these four systems. The Chemistry Control Program is described in Section 4.6 of Exhibit A of the Application. Since these four systems are a part of the plant secondary, the internal environment is maintained by the Secondary Chemistry Control Specifications, described in the Section 4.6.3, which is a part of the Chemistry Control Program.

As identified in Table 3.5-7, the inspections and analyses that manage some of the aging effects in these four systems are performed by either the Piping Erosion/Corrosion Program, Cast Iron Selective Leaching Inspection, Preventive Maintenance Activities, Service Water Piping Corrosion Program, or the Galvanic Susceptibility Inspection. These programs, inspections, and activities are described in detail in the following sections of Exhibit A of the Application:

Piping Erosion/Corrosion Program	Section 4.21
Cast Iron Selective Leaching Inspection	Section 4.3.2
Preventive Maintenance Activities	Section 4.3.8
Service Water Piping Corrosion Program	Section 4.25
Galvanic Susceptibility Inspection	Section 4.3.3

Please refer to these sections for more program details.

RAI 3.5.9-2

For the condensate cooler tubing and main condenser tubing examinations, provide the scope of the examination, the examination method, the acceptance criteria, the frequency of such examinations and relevant Oconee-specific operating experience related to the performance of the condensate coolers and main condensers to date. Provide the bases to show how these examinations are appropriate for timely detection of aging effects.

Response to RAI 3.5.9-2

The response to this RAI is also provided in the response to RAI 4.3.8-1. The discussion on the condensate coolers and the main condenser are repeated for the convenience of the reader.

Condensate Coolers:

The purpose of the Condensate Cooler Tubing Examination is to determine the condition of the exterior surface of the stainless steel tubes of the condensate coolers. The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry, are tested. Approximately 25% of the cooler tubes are tested. Loss of material of the exterior surface of the stainless steel tubes exposed to raw water has been identified as an applicable aging effect for the condensate coolers in the Condensate System. Eddy current testing is performed to identify wall loss indications. The examination is currently performed every third refueling outage.

The acceptance criterion is no wall loss greater than 60%. Tubes with wall loss indications greater than 60%, subject to engineering evaluation, are plugged. This examination is performed by a vendor and is implemented per the vendor's procedure in accordance with the quality control program of that organization. This periodic examination has no current regulatory basis.

Main Condenser:
The purpose of the Main Condenser Tubing Examination is to determine the condition of the stainless steel tubes of the main condensers. Each main condenser is a rectangular shell, single pass, divided waterbox and surface type condenser with internal air cooling sections. Each main condenser has three main condenser shells and each shell is provided with two water boxes. There are approximately 8,500 tubes per waterbox. Approximately 10% of the condenser tubes in one-half of the condenser (three of the six waterboxes) are examined each refueling outage. Loss of material of the stainless steel tubes exposed to raw water has been identified as an applicable aging effect for the main condenser in the Condensate System. Eddy current testing is performed to identify wall loss indications.

The acceptance criterion is no wall loss greater than 60%. Tubes with wall loss indications greater than 60%, subject to engineering evaluation, are plugged. This examination is performed by a vendor and is implemented per the vendor's procedure in accordance with the quality control program of that organization. This periodic examination has no current regulatory basis.

RAI 3.5.9-3
Portions of the main steam system and the feedwater system are located in the Auxiliary Building. As described in Section 3.5.2.7.2, the Boric Acid Wastage Surveillance Program is cited to manage loss of material due to exposure to borated water/boric acid for components located in the Auxiliary Building. However, the LRA indicates that the scope of the Boric Acid Wastage Surveillance Program is limited to the Reactor Building. Identify where in the LRA that the Boric Acid Wastage Surveillance Program includes all applicable portions of the main steam and feedwater systems or discuss how loss of material due to boric acid wastage is managed for components of the main steam and feedwater systems located in the Auxiliary Building.

Response to RAI 3.5.9-3
Section 4.5 of Exhibit A of the Application, Boric Acid Wastage Surveillance Program, notes that the program scope includes mechanical components and structural components fabricated from carbon steel and low alloy steel both inside and outside the Reactor Building, which includes the Auxiliary Building.

RAI 3.5.9-4
Section 3.5.9 of the license renewal application states the applicable aging effects for the following systems:

- Main Steam System components, including piping and valves;

- Condensate System components, including the main condenser, the condensate coolers and the generator water coolers;

- Emergency Feedwater System, including piping and valves; and

- Feedwater System, including piping and valves.

The LRA also states that the related aging effects will be managed by monitoring and controlling the effects directly. In addition, inspections and analyses are performed to investigate and verify the integrity of the piping systems. In Section 3.5.9.4.3, the licensee identifies the Chemistry Control Program and the Piping Erosion/Corrosion Program as the appropriate means to manage the applicable aging effects. However, the LRA, Section 3.5.2, identified cracking due to vibration as a potential aging effect.

For each of these systems, provide the following information:

1. A description of the methods and equipment that will be used for monitoring and controlling the aging effects combined with mechanical vibrations.

2. A description of the inspection and analysis performed to investigate and verify the integrity of the piping systems, including piping and component supports, for combined aging effects and mechanical vibrations.

Response to RAI 3.5.9-4
Section 3.2 of Exhibit A of the Application describes the process used by Duke to identify the *applicable* aging effects for the structures and components subject to an aging management review. First, a list of *potential* aging effects to consider for Oconee structures and components subject to an aging management review were identified by reviewing available industry literature. In addition, the material and service environment required for the onset and propagation for each potential aging effect were identified. Next, for those Oconee structures and components subject to an aging management review, the plant-specific materials of construction and service environment were identified. The potential aging effects became applicable aging effects for the Oconee structures and components when both the plant-specific materials of construction and service environment match the materials and service environment necessary for the potential aging effect to occur and the

component-aging effect combination could result in a loss of the component intended function during the extended period of operation if left unmanaged. To provide reasonable assurance that all of the applicable aging effects had been identified for the structures and components subject to an aging management review, NRC generic communications, industry experience, and relevant Oconee experience were also reviewed.

Section 3.5.2 presents all the potential aging effects that were considered for applicability to Oconee mechanical system components. One of the potential aging effects considered for Oconee was cracking due to vibration. Cracking due to vibrational (mechanical or hydrodynamic) loads was a potential aging effect that was determined to be not applicable to Oconee structures and components subject to an aging management review. Cracking due to vibration can be attributed to insufficient design. Vibration characteristically leads to cracking in a short period of time, on the order of hours to days of operation. For example, a component with a 1 Hz vibratory load will be subjected to 10^7 cycles in four months of service, so that failure is probable early in life for vibratory stresses above the endurance limit. Because this time period is short when compared to the overall plant operational life, any cracking will be identified and corrected to prevent recurrence long before the period of extended operation. Therefore, cracking due to vibrational loads, both mechanical and hydrodynamic, is not an applicable aging effect for the Oconee structures and components subject to an aging management review.

Loss of material and cracking are applicable aging effects for the components in these systems that are managed by one or more of the programs listed in the response to RAI 3.5.9-1. Please refer to this response for the programs credited to manage the applicable aging effects for the components in these four systems.

Exhibit A, Section 4.3.2, Cast Iron Selective Leaching Inspection

RAI 4.3.2-1
If the Brinell Hardness check indicates that selective leaching has occurred in an inspected cast iron component, what methods will be used to determine the amount of material lost and ensure that it did not exceed the limit required for qualifying the component for further service?

Response to RAI 4.3.2-1
Any indication of loss of material due to selective leaching identified during the Cast Iron Selective Leaching Inspection will initiate the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For conditions warranting such action, PIP confirms the identified condition has been addressed. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost, and determine corrective actions that assure a degraded component condition did not exceed the limit required for qualifying the component for further service.

Exhibit A, Section 4.3.8, Preventive Maintenance Activity Assessment

RAI 4.3.8-1
It is the staff's understanding that Section 4.3.8, "Preventive Maintenance Activity Assessment" is the aging management program to which the licensee refers in the Chapter 3 descriptions as "Preventive Maintenance Activities." With that assumption, the staff expected to find in Section 4.3.8 a description of various aging management programs (including inspection activities, schedules, acceptance criteria, etc.). Instead, Section 4.3.8 contains a description of a program that will assess the effectiveness of various preventive maintenance activities by the end of the licensee's current operating license. Clarify the intent of the subject "program" and discuss how it differs from Oconee's current self-assessment program. Provide a description of the preventive maintenance program(s) that will be used to manage the applicable aging effects in the LRA. Discuss whether the specific inspections listed in Table 4.3-1 are considered aging management programs unto themselves.

Response to RAI 4.3.8-1
At Oconee, maintenance activities have been established to assure safe, reliable, and efficient operation of the plant. Some of these maintenance activities were identified as aging management activities for license renewal and have been specifically identified as Preventive Maintenance Activities in Section 4.3.8 of Exhibit A of the Application.

Even though most of these activities contain the attributes as defined in Section 4.2, the activities lack sufficient documentation to demonstrate the effectiveness of these activities as specified in §54.21 (a)(3). The intent of the assessment identified in Section 4.3.8 Exhibit A of the Application is to measure these activities against the attributes in Section 4.2, document and analyze the results, and demonstrate that the activities adequately manage the effects of aging so that the intended function(s) of the structures and components will be maintained consistent with the current licensing basis for the period of extended operation. This assessment will be a distinct part of the current Oconee self-assessment process.

The Preventive Maintenance Activities that are being credited as new aging management activities for license renewal and that are included within the scope of the assessment are:

- Auxiliary Service Water Piping Inspection
- Borated Water Storage Tank Internal Coatings Inspection
- Component Cooler Tubing Examination
- Condensate Cooler Tubing Examination
- Condenser Circulating Water System Internal Coatings Inspection
- Decay Heat Cooler Tubing Examination
- Main Condenser Tubing Examination
- Reactor Building Cooling Unit Tubing Inspection
- Standby Shutdown Facility Diesel Fuel Oil Tank Inspection
- Turbine Generator Cooling Water System Strainer Inspection

The attributes defined in Section 4.2 of the application are identified for each activity, as applicable, in the following sections.

Preventive Maintenance Activities
Auxiliary Service Water Piping Inspection
Activity Attributes

Purpose - The purpose of the Auxiliary Service Water Piping Inspection is to visually inspect the interior surface of the piping in the vicinity of the pump discharge check valve to determine the general condition of the piping. This location is downstream of the recirculation line and is stagnant. This location is expected to be indicative of the entire section of piping and associated components that contain raw water. 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.

Scope - The interior surface of the piping in the vicinity of the pump discharge check valve is visually inspected.

Aging Effects - Loss of material

Method - During check valve disassembly, the piping in the vicinity of the valve is inspected.

Sample Size - Not applicable for an existing activity.

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

Frequency - The piping is inspected once every five years.

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

Corrective Action – Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by repair or replacement.

Timing of New Program or Activity - The Auxiliary Service Water Piping Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - The inspection is performed per a standing work order. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic visual inspection is being implemented in response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

Preventive Maintenance Activities
Borated Water Storage Tank Internal Coatings Inspection
Activity Attributes

Purpose - The purpose of the Borated Water Storage Tank Internal Coatings Inspection is to inspect the internal coating of the Borated Water Storage Tank to check the condition of the coating and to identify coating failures. The internal surfaces of the Borated Water Storage Tanks have a plasite protective coating that precludes exposure to borated water and air. Continued presence of an intact coating precludes loss of material of the internal surface material.

Scope - The interior plasite protective coating of each Borated Water Storage Tank is inspected.

Aging Effects - Loss of material

Method - A visual inspection of the coating is performed after the borated water is removed from the tank.

Sample Size - Not applicable for an existing activity.

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

Frequency - The inspection is performed every third refueling outage.

Acceptance Criteria or Standard - The acceptance criterion is no visual indications of coating defects that have lead to corrosion of the internal surfaces. Engineering evaluation is performed to determine whether coating continues to be acceptable.

Corrective Action - Corrective actions are based on engineering evaluation of inspection results.

Timing of New Program or Activity - The Borated Water Storage Tank Internal Coatings Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Control - This inspection is performed by work order. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic inspection has no current regulatory basis.

Preventive Maintenance Activities
Component Cooler Tubing Examination
Activity Attributes

Purpose - The purpose of the Component Cooler Tubing Examination is to determine the condition of the interior surfaces of the brass tubes of the component coolers.

Scope - 100% of cooler tubes are examined.

Aging Effects - Loss of material

Method - Eddy current testing is performed to identify wall loss indications.

Sample Size - Not applicable for an existing activity.

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

Frequency - The examination is performed every other refueling outage.

Acceptance Criteria or Standard - All tube wall loss indications are less than 60% through wall.

Corrective Action - Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged.

Timing of New Program or Activity - The Component Cooler Tubing Examination is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This examination is performed by a vendor and implemented per the vendor's procedure in accordance with the quality control program of that organization. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic examination has no current regulatory basis.

Preventive Maintenance Activities
Condensate Cooler Tubing Examination
Activity Attributes

Purpose - The purpose of the Condensate Cooler Tubing Examination is to determine the condition of the exterior surface of the stainless steel tubes of the condensate coolers.

Scope - The most susceptible tubes, those along the perimeter and those at the baffle regions that will experience turbulence due to the baffle geometry (approximately 25% of the tubes), are tested.

Aging Effects - Loss of material

Method - Eddy current testing is performed to identify wall loss indications.

Sample Size - Not applicable for an existing activity.

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

Frequency - The examination is performed every third refueling outage.

Acceptance Criteria or Standard - All wall loss indications are less than 60% through wall.

Corrective Action - Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged.

Timing of New Program or Activity - The Condensate Cooler Tubing Examination is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This examination is performed by a vendor and is implemented per the vendor's procedure in accordance with the quality control program of that organization. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic examination has no current regulatory basis.

Preventive Maintenance Activities
Condenser Circulating Water System Internal Coatings Inspection
Activity Attributes

Purpose - The purpose of the Condenser Circulating Water System Internal Coatings Inspection is to inspect the internal coating of the large diameter Condenser Circulating Water System underground piping to check the condition of the coating and to look for coating failures. This inspection provides indications of the condition of the piping, including symptomatic evidence of the condition of the piping external surfaces.

Scope - The interior surfaces of the underground Condenser Circulating Water System intake and discharge piping are inspected.

Aging Effects - Loss of material

Method - A visual inspection of the interior surface is performed.

Sample Size - Not applicable for an existing activity.

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

Frequency - The inspection is performed every five years.

Acceptance Criteria or Standard – No visual indications of coating defects that reveal corrosion of the piping as determined by Engineering.

Corrective Action – Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by repair.

Timing of New Program or Activity - The Condenser Circulating Water System Internal Coatings Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This inspection is performed by work order. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic visual inspection is being implemented in response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

Preventive Maintenance Activities
Decay Heat Cooler Tubing Examination
Activity Attributes

Purpose - The purpose of the Decay Heat Cooler Tubing Examination is to determine the condition of the exterior surface of the stainless steel tubes of the decay heat coolers.

Scope - 100% of the inservice stainless steel heat exchanger tubes are examined.

Aging Effect - Loss of material

Method - Eddy current testing is performed to identify wall loss indications.

Sample Size - Not applicable for an existing activity.

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

Frequency - The examination is performed every fourth refueling outage.

Acceptance Criteria or Standard - All wall loss indications are less than 60% through wall.

Corrective Action - Tubes with wall loss indications greater than 60% through wall are plugged.

Timing of New Program or Activity - The Decay Heat Cooler Tubing Examination is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This examination is performed by a vendor and is implemented per the vendor's procedure in accordance with the quality control program of that organization. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic examination has no current regulatory basis.

Preventive Maintenance Activities
Main Condenser Tubing Examination
Activity Attributes

Purpose - The purpose of the Main Condenser Tubing Examination is to determine the condition of the stainless steel tubes of the main condensers.

Scope - Ten percent of the tubes in one-half of the condenser each refueling outage are examined.

Aging Effects - Loss of material

Method - Eddy current testing is performed to identify wall loss indications.

Sample Size - Not applicable for an existing activity.

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

Frequency - Tubing examinations are performed each refueling outage on one-half of the condenser. Tubes in each half of the condenser are examined every other refueling outage.

Acceptance Criteria or Standard - All tubing wall loss indications are less than 60% through wall.

Corrective Action - Tubes with wall loss indications greater than 60% through wall receive an engineering evaluation to justify continued service or are plugged.

Timing of New Program or Activity - The Main Condenser Tubing Examination is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This examination is performed by a vendor and is implemented per the vendor's procedure in accordance with the quality control program of that organization. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic examination has no current regulatory basis.

Preventive Maintenance Activities
Reactor Building Cooling Unit Tubing Inspection
Activity Attributes

Purpose - The purpose of the Reactor Building Cooling Unit (RBCU) Tubing Inspection is to clean the RBCUs and inspect the tubes and aluminum and galvanized steel ductwork and internal supports of the system to determine their condition.

Scope - The scope of this inspection includes the waterside (tubes) and airside (shell) of the Reactor Building Cooling Units and the aluminum and galvanized steel ductwork and internal supports.

Aging Effects - Loss of material

Method - The tubes are rodded out and visually inspected. The shell is cleaned and visually inspected. The ductwork and internal supports are visually inspected.

Sample Size - Not applicable for an existing activity.

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

Frequency - The waterside procedure is performed every refueling or as required by periodic performance testing. Similarly, the airside procedure is performed as required by performance testing. Inspections of the ductwork and internal supports will be performed on the air side frequency.

Acceptance Criteria or Standard – No unacceptable visual indications of loss of material as determined by Engineering.

Corrective Action - Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by repair or refurbishment.

Timing of New Program or Activity - The Reactor Building Cooling Unit Tubing Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Controls - This inspection is performed by controlled procedures. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic visual inspection is being implemented in response to GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment."

Preventive Maintenance Activities
Standby Shutdown Facility Diesel Fuel Oil Tank Inspection
Activity Attributes

Purpose - The purpose of the Standby Shutdown Facility (SSF) Diesel Fuel Oil Tank Inspection is to inspect the interior surface of the SSF Diesel Generator Fuel Oil Tank for symptomatic evidence of external corrosion due to voids in the external coating.

Scope - The scope of the inspection includes the interior surface of the SSF Diesel Generator Fuel Oil Tank.

Aging Effects - Loss of material

Method - A visual inspection of the interior surface of the tank is performed after the fuel oil is removed from the tank.

Sample Size - Not applicable for an existing activity.

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

Frequency - This inspection is performed every ten years.

Acceptance Criteria or Standard - No visual indications of loss of material as determined by Engineering.

Corrective Action – Areas which do not meet the acceptance criteria are evaluated for continued service or corrected by repair.

Timing of New Program or Activity - The Standby Shutdown Facility Diesel Fuel Oil Tank Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, the assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Control - This inspection is implemented by controlled procedures. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic inspection has no current regulatory basis.

Preventive Maintenance Activities
Turbine Generator Cooling Water System Strainer Inspection
Activity Attributes

Purpose - The purpose of the Turbine Generator Cooling Water System Strainer Inspection is to clean and inspect the strainers in the Turbine Generator Cooling Water System. This activity ensures that aging of the strainer medium, which provides the required filtering function, is managed.

Scope - The turbine packing box cooling water and the main inlet strainers are covered under this program.

Aging Effects - Loss of material

Method - The strainers are removed from service and inspected for any evidence of loss of material of the strainer medium.

Sample Size - Not applicable for an existing activity.

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

Frequency - The activity is performed on the turbine packing box cooling water strainer weekly and on the main inlet strainer bimonthly.

Acceptance Criteria or Standard - Any noticeable sign loss of material is documented.

Corrective Action - All documented loss of material receives an engineering evaluation to justify either continued service of the strainer medium or replacement of the medium.

Timing of New Program or Activity - The Turbine Generator Cooling Water System Strainer Inspection is an existing maintenance activity that will be continued into the extended period of operation. Following issuance of renewed operating licenses for Oconee Nuclear Station, at least one assessment of this activity will be performed by February 6, 2013 (the end of the initial license for Oconee Unit 1).

Administrative Control - This inspection is performed per controlled procedures. The responsible engineer may adjust the attributes of this inspection provided such changes do not adversely impact the capability of the activity to manage the effects of aging.

Regulatory Basis - This periodic inspection has no current regulatory basis.

RAI 4.3.8-2

An aging effect for the Auxiliary Service Water Piping (Table 4.3-1) is described as "[f]ouling due to macro-organisms and silting has been identified as an applicable aging effect for specific portions of the Auxiliary Service Water System piping...." This aging effect is not consistent with the aging effect described in Section 3.5.6.2, "Auxiliary Service Water System" that describes the applicable aging as the "loss of material for the subject components exposed to an air environment will be...." Provide a clarification of the aging effects and the applicable aging management program such that the staff can evaluate that the effects of aging are being managed consistent with the current licensing basis.

Response to RAI 4.3.8-2

The Auxiliary Service Water System is exposed to two environments: a raw water environment and an air environment. The portion of the system upstream of the pump discharge valve is exposed to raw water. The portion of the system between the pump discharge valve and the isolation valves to the Emergency Feedwater header and the HPI motor bearing cooling jacket valves LPSW-502 as shown on OLRFD 124B-1.1, 2.1, and 3.1. is drained and exposed to an air environment. Table 3.5-4 of Exhibit A of the Application documents the components, materials, environments, aging effects and programs for this system.

Section 3.5.6.2.2 of Exhibit A of the Application identifies the applicable aging effects for the system components in a raw water environment. The applicable aging effects for these components are loss of material and fouling. Section 3.5.6.2.2 also identifies the applicable aging effect for the system components in an air environment. The applicable aging effect for these components is loss of material. Section 3.5.6.2.3 and Table 3.5-4 identify the programs and activities that are credited with managing the aging effects for the Auxiliary Service Water System components in the raw water and air environment. Section 3.5.6.2.3 and Table 3.5-4 correctly state that only loss of material in an air environment is managed by the Preventive Maintenance Activities. Table 4.3-1 is incorrect in stating that the Auxiliary Service Water Piping Inspection portion of the Preventive Maintenance Activities is associated with fouling. The table should have associated the activity with loss of material in an air environment and not fouling.

RAI 4.3.8-3

Table 4.3-1, "Preventive Maintenance Activities," describes aging effects for the Component Cooling System and identifies a component cooler tubing examination. However, Section 3.5.4.2, "Component Cooling System" contains no reference to Preventive Maintenance Activities. Clarify the discrepancy.

Response to RAI 4.3.8-3

The component coolers are a part of the Component Cooling System. However, for license renewal the coolers do not perform a component intended function in support of the Component Cooling System intended functions within the scope of license renewal. These coolers are cooled by cooling water supplied by the Low Pressure Service Water System. The component coolers are required to perform a pressure boundary function in support of the Low Pressure Service Water System intended functions within the scope of license renewal and were screened into license renewal with the Low Pressure Service Water System components in Table 2.5-9 of Exhibit A of the Application. Since the component intended function of the coolers is required in support of the Low Pressure Service Water System only and not the Component Cooling System, they were listed with the Low Pressure Service Water System and addressed in Section 3.5.6.5. Table 4.3-1 should have stated that the applicable aging effects for the cooler are with the Low Pressure Service Water System, not the Component Cooling System.

RAI 4.3.8-4

Table 4.3-1, "Preventive Maintenance Activities," contains the following description for the aging effects of the Reactor Building Cooling Unit Tubing: "Loss of material due to general and localized corrosion of the tube side exposed to raw water and localized corrosion due to galvanic corrosion and boric acid wastage...." This description is not consistent with the description given in Section 3.5.3.1, "Reactor Building Cooling System," that cites preventive maintenance activities to prevent "loss of material...exposed to a ventilation air environment..." The loss of material due to a ventilation air environment is not discussed in Table 4.3-1. In addition, the loss of material due to galvanic corrosion and boric acid wastage corrosion is not discussed in Section 3.5.3.1. Clarify these discrepancies.

Response to RAI 4.3.8-4

The Reactor Building Cooling System components are exposed to several environments. System components are exposed externally to the Reactor Building ambient conditions and internally to a ventilation air environment. In addition, the Reactor Building cooling units are exposed to raw water (from the Low Pressure Service Water System) through the tubes and ventilation air through the ducts and on the outside of the tubes.

For the components exposed to ventilation air, Section 3.5.3.1.2 of Exhibit A of the Application identifies the applicable aging effect for the system components. The applicable aging effect for these components is loss of material. Section 3.5.3.1.3 identifies the programs and activities that are credited with managing the aging effect for the components in a ventilation air environment. Loss of material is managed by maintenance activities, which are implemented by Preventive Maintenance Activities found in Section 4.3.8. Table

4.3-1 should have noted that the loss of material from localized corrosion due to galvanic corrosion and boric acid wastage was in the ventilation air environment.

For the portion of the Reactor Building cooling units exposed to a raw water environment, Section 3.5.3.1.2 identifies the applicable aging effects. The applicable aging effects for these components are loss of material and fouling. Section 3.5.3.1.3 identifies the programs and activities that are credited with managing the aging effects for the components in a raw water environment. Loss of material and fouling will managed by testing and maintenance activities which are implemented by Heat Exchanger Performance Testing Activities and Preventive Maintenance Activities found in Sections 4.17 and 4.3.8, respectively.

RAI 4.3.8-5

Table 4.3-1, "Preventive Maintenance Activities," contains the following description for the aging effects associated with the carbon steel strainers in the Turbine Generator Cooling Water System: "Loss of material due to general and localized corrosion...." Confirm that the "filters" listed in Table 3.5-11, "Applicable Aging Effects for Components of Keowee Hydroelectric Station Systems" are the same components called "strainers" in Section 4.3.8, "Preventive Maintenance Activities Assessment."

In addition, Section 3.5.13.7, "Turbine Generator Cooling Water System" discusses fouling as an applicable aging effect. Stainless steel strainers are included in Table 3.5-11. Fouling is not considered as an aging effect in Table 4.3-1. Discuss why fouling of stainless steel strainers are not identified as an applicable aging effect in Table 4.3-1.

Response to RAI 4.3.8-5

Table 3.5-11 of Exhibit A of the Application should have listed strainers and not filters to agree with Section 4.3.8. No filters are found in the Turbine Generator Cooling Water System.

Table 3.5-11 identifies the Preventive Maintenance Activities and System Performance Testing Activities for managing fouling of stainless steel strainers. This is an error in Table 3.5-11. Only System Performance Testing Activities that are described in Section 4.27 of Exhibit A of the Application manage fouling of the stainless steel strainers and all the other components in the Turbine Generator Cooling Water System. Table 4.3-1 is correct in noting that Preventive Maintenance Activities only manage loss of material of system components.

RAI 4.3.8-6

In Table 4.3-1, "Preventive Maintenance Activities," the aging effect for the Condensate Cooler Tubing examination differs from that for the Main Condenser Tubing examination. Explain why micro biologically influenced corrosion is considered for one and not the other although the materials and environment appear to be similar. Discuss why fouling is not considered an applicable aging effect for the portions of the condensate system exposed to a raw water environment.

Response to RAI 4.3.8-6

Duke and industry experience has shown that micro-biologically influenced corrosion occurs in the heat affected zones of component welds because of the potential for chromium depletion in these zones. The stainless steel tubes of the condensate coolers are rolled-in such that there are no such heat affected zones. Therefore, loss of material due to micro-biologically influenced corrosion is not an applicable aging effect for the Condensate Coolers. The Main Condenser does, in turn, have welded tubing, and thus for the heat affected zones of this tubing, loss of material due to micro-biologically influenced corrosion is an applicable aging effect.

Fouling is an aging effect that affects the heat transfer efficiency of heat exchangers, but does not affect the pressure boundary function. The component intended function of the condensate coolers and main condenser is to maintain pressure boundary. These heat exchangers are not depended upon to provide heat transfer. Therefore, fouling is not an applicable aging effect for these coolers.

Exhibit A, Section 4.3.9, Reactor Building Spray System Inspection

RAI 4.3.9-1

In Section 3.5.3.2, "Reactor Building Spray System," the LRA states that "the loss of material and cracking for the stainless steel components exposed to an air environment have not been fully characterized and their applicability will need to be verified by a one-time inspection [the Reactor Building Spray System Inspection]." The Reactor Building Spray System is not included in Section 3.5.2.6 "Applicable Aging Effects for a Ventilation Air Environment." In Section 3.5.2.6, the LRA also states that "stainless steel materials in the plant air environments are resistant to general corrosion." Clarify these discrepancies.

In addition, Section 4.3.9 identified "the loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components...exposed to a borated water environment...." These aging effects are not identified in Section 3.5.3.2. Clarify this discrepancy.

Response to RAI 4.3.9-1

The Reactor Building Spray System has the internal environments of borated water and Reactor Building atmosphere, not a ventilation air environment. The mechanical components upstream of check valves BS-14 and BS-19 toward the pumps as shown on drawings OLFRD-103A-1.1, 2.1, and 3.1 are exposed to a borated water environment. The Reactor Building Spray System components between check valves BS-14 and BS-19 to the spray rings are open to the Reactor Building atmosphere through the normally open valves BS-15 and BS-20 and the open spray nozzles of the spray ring. Therefore, these components experience a Reactor Building air environment internally, not a ventilation air environment, and are addressed in Section 3.5.2.7 of Exhibit A of the Application. Section 3.5.2.6 discusses the effects of the ventilation air environment that is found only inside ventilation systems. Therefore, Section 3.5.2.6 is not applicable to the Reactor Building spray system components.

The potential aging effects of concern are loss of material and cracking of a very specific portion of the Reactor Building Spray System due to routine operations. The borated water storage tank provides the suction source for the Reactor Building Spray System. When the valves BS-1 and BS-2 are partially opened and closed for routine testing, water pressure downstream of BS-1 and BS-2 rises due to the pressure head provided by the borated water storage tank that partially opens check valves BS-14 and BS-19. Borated water is introduced to the air portion of the system and removed by the open drain valves BS-15 and BS-20. As a result, surfaces are alternately wetted and dried in the components between the check valves BS-19 and BS-20 and the open drain valves BS-15 and BS-20. This alternate wetting and drying could concentrate halogens and sulfates and may create an environment conducive to the loss of material due to pitting corrosion and cracking due to stress corrosion

of stainless steel components identified in Section 4.3.9 of Exhibit A of the Application. This area of alternate wetting and drying is within the scope of the Reactor Building Spray System Inspection that is identified in Section 3.5.3.2.3 and described in Section 4.3.9.

RAI 4.3.9-2

The Reactor Building Spray System Inspection will be completed by February 6, 2013 (the end of the initial license of Oconee Unit 1). The staff finds this date to be unacceptable without additional information. Provide a justification for not completing the inspection activities at the time of application. Along with your justification, describe the methodology, identify any applicable acceptance criteria, identify planned corrective actions, and provide a schedule for implementation.

Response to RAI 4.3.9-2

By letter dated May 19, 1997, Duke submitted an example of the level of detail proposed for a license renewal application to describe a new inspection program. The staff reviewed this example and provided written feedback by letter dated August 13, 1997 (Reference 4.2-3 of Exhibit A of the Application).

Within this letter, staff technical comment #2 indicated that, for the example provided, the examination should be provided during the last two periods of the fourth interval. Duke understood this staff comment to mean that all new inspections and examinations required for license renewal should be performed toward the end of the initial 40-year operating license rather than earlier.

The timing of new program and activity implementation is a question that is applicable to all of the new programs and activities described in Section 4.3 of Exhibit A of the Application. Duke supports further discussion of this question in order to determine the appropriate timing of when each of these new programs and activities should be implemented.

With respect to the second part of the question, a description of the methodology, applicable acceptance criteria, corrective actions, and scheduled for implementation for the Reactor Building Spray System Inspection is provided in Section 4.3.9 of Exhibit A of the Application.

RAI 4.3.9-3

Explain whether the Reactor Building Spray System Inspections provide for sample expansion or follow up inspections if unacceptable indications are. If not, please justify.

Response to RAI 4.3.9-3

As discussed in the response to RAI 4.3.9-1, the scope of the Reactor Building Spray System Inspection is the mechanical components between check valves BS-14 and BS-19 and the drain valves BS-15 and BS-20 that experience alternate wetting and drying. From Section 4.3.9 of Exhibit A of the Application, one of six possible locations (two per unit) will be inspected to determine the applicability of loss of material and cracking in the region exposed to alternate wetting and drying. Any indication of loss of material or cracking identified during the Reactor Building Spray System Inspection will initiate the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost. The piping evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service.

RAI 4.3.9-4

Please discuss the confirmation process for the Reactor Building Spray System Inspections, i.e., when corrective actions are completed, what are the follow up activities that are done to confirm that the corrective actions are completed, a root cause determination is performed, and recurrence is prevented. (The discussion of this element in your quality assurance program was not clear, stating that it applied to "more significant events.")

Response to RAI 4.3.9-4

Any indication of loss of material due to pitting corrosion or cracking or cracking due to stress corrosion identified during the Reactor Building Spray System Inspection will be evaluated using the Problem Investigation Process (PIP). The PIP is a process governed by a nuclear generation department directive that will initiate an engineering evaluation of the identified condition. The PIP evaluation is the confirmation process. The PIP evaluation is designed to consider the need to conduct a root cause analysis and determine corrective actions, which may include actions to prevent recurrence. For conditions warranting such action, PIP confirms the identified condition has been addressed. For this example, the PIP evaluation will determine the need for a root cause analysis, including the establishment of methods to determine the amount of material lost. The piping evaluation will also determine corrective actions that assure a degraded component condition has not or will not exceed the limit required for qualifying the component for further service

RAI 4.3.9-5

For Reactor Building Spray System Inspections, discuss Oconee or applicable industry operating experience from similar programs or inspection techniques used to develop this inspection program.

Response to RAI 4.3.9-5

As discussed in the response to RAI 4.3.9-1, the scope of the Reactor Building Spray System Inspection is the mechanical components between check valves BS-14 and BS-19 and the drain valves BS-15 and BS-20 that experience alternate wetting and drying. No Oconee or applicable industry operating experience from similar programs or inspection techniques were used to develop this inspection.

Exhibit A, Section 4.6, Chemistry Control Program

Primary Water Chemistry:

RAI 4.6.2-1

Were there any instances during operation of the plant when the control parameters for primary water chemistry exceeded EPRI's Corrective Action Level 3, which, according to EPRI guidelines required immediate plant shutdown? If such incidents have occurred, specify the parameters that exceeded the Action Level 3 limits. Identify any noted effects on the plant from these incidents, and identify any programmatic or corrective actions taken.

Response to RAI 4.6.2-1

No incidents have occurred at Oconee where control parameters for primary water chemistry exceeded EPRI Corrective Action Level 3.

RAI 4.6.2-2

Describe which of the following chemistry regimes were used in controlling pH in the reactor coolant system:

- Coordinated Chemistry
- Modified Chemistry
- Elevated Lithium Chemistry

Response to RAI 4.6.2-2

At Oconee, all three chemistry regimes have been used. Originally, the Coordinated Chemistry regime was used on all three Oconee Units. Later, the Coordinated Chemistry regime was replaced by the Modified Chemistry regime. For an EPRI pilot demonstration, Oconee Unit 2 was placed on the Elevated Lithium Chemistry regime for fuel cycle 12. Following completion of the pilot demonstration, Oconee Unit 2 was returned to the Modified Chemistry regime. Oconee Unit 2 permanently replaced the Modified Chemistry regime with the Elevated Lithium Chemistry regime at the start of fuel cycle 17. Current plans are to replace the Modified Chemistry regime on Units 1 and 3 with the Elevated Lithium Chemistry regime during fuel cycles 19 (1999) and 18 (December 1998), respectively.

RAI 4.6.2-3
Describe the frequency of sampling for chloride and sulfate in the spent fuel pool and provide maximum acceptable concentrations for these impurities.

Response to RAI 4.6.2-3
Currently, the Spent Fuel Pool is sampled for chlorides on a monthly frequency except during fuel movement. During fuel movement, sample frequency for chlorides is increased to weekly. The maximum acceptable concentration for chlorides is less than 150 ppb.

Currently, the Spent Fuel Pool is sampled for sulfates on a quarterly frequency. Consistent with the EPRI Primary Water Chemistry Guidelines, no maximum acceptable concentration of sulfates for the Spent Fuel Pool is specified.

RAI 4.6.2-4
Were there any significant corrosion incidents (i.e., causing replacement or major repair of a component) in the past affecting carbon steel components exposed to the borated water in the spent fuel pool and its supporting systems? If such incidents have occurred, describe them.

Response to RAI 4.6.2-4
There are no carbon steel components exposed to borated water in the spent fuel pool or its supporting Spent Fuel Cooling System. The first paragraph of Section 3.7.3.3 of Exhibit A of the Application addresses the material of construction for the components in the spent fuel pool and states that the spent fuel pool liner and storage racks are constructed of stainless steel. Table 3.5-4 addresses the material of construction for the components in the Spent Fuel Cooling System and indicates that all components within the system are constructed of stainless steel.

Secondary Water Chemistry:
RAI 4.6.3-1
What are the maximum allowable concentrations of silica and iron required by your secondary water chemistry specifications?

Response to RAI 4.6.3-1
Consistent with the guidance provided by the EPRI Secondary Water Chemistry Guidelines for plants with once through steam generators, the maximum allowable silica is less than 10 ppb and the maximum allowable iron is less than 3 ppb.

RAI 4.6.3-2
Were there any significant secondary water chemistry excursions (i.e., greater than level 3 excursions according to EPRI guidelines) in the past? If such excursions have occurred, describe any significant impact on the condition of the plant, such as increased potential for corrosion damage of the components in the secondary water system.

Response to RAI 4.6.3-2
Oconee steam generators are classified as once through steam generators. EPRI Secondary Water Chemistry Guidelines do not define "level 3" limits for once through steam generators. The guidelines do establish limits that require the immediate shutdown of the plant (i.e., sodium > 10 ppb, chloride > 20 ppb, cation conductivity > 2.0, silica > 50 ppb). Oconee has not had any excursions that have exceeded these limits.

Component Cooling Water Chemistry:
RAI 4.6.4-1
Provide the limits, target values, and inspection frequencies for water chemistry parameters monitored for the component cooling system. Also, generally describe the procedures that are used to maintain the chemistry parameters within these values.

Response to RAI 4.6.4-1
Loss of material for components within the Component Cooling System is managed through the use of corrosion inhibitors that are maintained by the Closed Cooling Water Specifications of the Chemistry Control Program in Section 4.6.4 of Exhibit A of the Application. Chromate and phosphate corrosion inhibitors are added to the system and maintained within certain concentration ranges. Samples are drawn and analyzed weekly to determine chromate and phosphate concentrations. Chromate concentrations are maintained between 150-250 ppm. Phosphate concentrations are maintained between 100-300 ppm.

Samples are drawn weekly and analyzed using accepted chemistry practices established in station chemistry procedures to determine chromate and phosphate concentrations. The concentrations are compared to the acceptable ranges stated earlier. If the concentrations are within the acceptable ranges, no further action is required. However, if concentrations are outside the acceptable ranges, corrective measures are taken to return these concentrations to within the acceptable range. If the concentrations are high, the system is bled and demineralized water is added to the system for dilution. If the concentrations are low, corrosion inhibitor is added to the system. Samples are drawn and analyzed to verify that the corrective actions taken have been effective in returning chromate and phosphate concentrations to within their acceptable ranges.

Exhibit A, Section 4.21, Piping Erosion/Corrosion Program

RAI 4.21-1
Describe your erosion/corrosion program by providing the following information:

a. Provide a description of the methodology for predicting degradation of the components in the Main Steam and Feedwater Systems,

b. Identify any predictive codes, such as CHECWORKS or other similar codes, used in the program,

c. Describe the methods used for trending material loss in the components susceptible to erosion/corrosion,

d. Describe any other predictive methods, besides computer codes, which may be used in the program, and

e. Describe the inspection methods used in determining the degree of degradation for the components determined to be affected by erosion/corrosion.

Response to RAI 4.21-1
The Piping Erosion/Corrosion Program is credited in Sections 3.5.9.1 and 3.5.9.4 of Exhibit A of the Application for managing loss of material due to erosion/corrosion for a limited scope of components falling within the scope of license renewal. The following additional information describes details of the program attributes described in Section 4.21 of Exhibit A of the Application:

a. The EPRI CHECWORKS FAC (Flow Accelerated Corrosion) module is currently used for predicting degradation in the feedwater system. The small portion of main steam piping included in the license renewal scope was evaluated using the KELLER equation and the guidelines in EPRI NP-3944, *Steam Piping Erosion/Corrosion Study*, during originally program development. Component inspections are performed in each of these systems and the results are processed as part of the program.

b. The EPRI CHEC family of computer codes has been used as the predictive tool in the Oconee Piping Erosion/Corrosion Program. The EPRI CHECWORKS FAC module is the predictive code currently being used.

c. The predictive model is validated by incorporating inspection data during each refueling outage. The inspection data is also trended independently based on projected wear rates. The predictive models and individual component evaluations are used to project future inspection needs and component service life.

d. Prior to the existence of the EPRI computer codes, the program developed inspection priorities based on the KELLER equation and the guidelines in EPRI NP-3944, *Steam Piping Erosion/Corrosion Study*. As stated above, this predictive method still forms the basis for some areas where use of the EPRI CHEC module was judged not to be viable. The Main Steam piping components within the scope of license renewal fall into this category.

e. Ultrasonic examinations are used in determining the degree of degradation for selected program components. Examinations are performed using industry accepted component grid mapping techniques. Radiography techniques are also used on a limited basis where component geometry may limit the use of ultrasonic examination to assess the existence and degree of loss the material.

RAI 4.21-2
Were there any other types of components within the scope of components requiring aging management review other than straight pipes (e.g., valves/pump bodies, elbows, "T" connections, etc.) included in the erosion/corrosion program? If there were none, provide a justification for excluding them from the program. If they were included, describe any unique inspections in the erosion/corrosion program for these components.

Response to RAI 4.21-2
All appropriate component types are included in the predictive models and component evaluations within the Piping Erosion/Corrosion Program. The program includes component nozzles, elbows, valves, tees, reducers, expanders, and straight pipes. Equipment bodies, including valves, cannot be inspected with standard ultrasonic techniques due to their shape and thickness. Therefore, in accordance with EPRI guidelines, the downstream piping is used as a leading indicator for these components and inspections are performed on the downstream piping or component nozzles, as appropriate, to detect suspected erosion/corrosion-related degradation.

RAI 4.21-3
List any significant component failure caused by erosion/corrosion that may have occurred in the past in the systems included in your license renewal application. Identify the component, and date of occurrence.

Response to RAI 4.21-3
No components in the portions of the Feedwater and Main Steam Systems included in the scope of license renewal have failed (experienced loss of component intended function) due to loss of material caused by erosion/corrosion.

RAI 4.21-4
For the components that failed due to erosion/corrosion, describe the corrective actions including replacement by materials resistant to erosion/corrosion damage (e.g., chrome-moly).

Response to RAI 4.21-4
No components in the portions of the Feedwater and Main Steam Systems included in the scope of license renewal have failed (experienced loss of component intended function) due to loss of material caused by erosion/corrosion. Hence, corrective actions have not been required.

RAI 4.21-5
Describe any special training provided to the personnel responsible for managing the erosion/corrosion program?

Response to RAI 4.21-5
The Piping Erosion/Corrosion Program personnel have been trained by EPRI in the use of the CHECWORKS computer codes and are active members of the EPRI CHECWORKS User's Group. This industry interface is enhanced by an active internal working group, which includes program managers from each of the Duke sites. The internal working group assures lessons learned from one site are provided to the other program managers.

EXHIBIT A, Section 5.7.1, Polar Crane

RAI 5.7.1-1

It is stated in Section 5.7.1 of the license renewal application that Oconee installed an Independent Spent Fuel Storage Installation (ISFSI), which became operational in 1990. The operation of the ISFSI required additional lifts by the spent fuel pool cranes near their rated lifting capacity. This resulted in a reevaluation of the fatigue concerns for the polar cranes through 60 years of operation. Even though the results of this reevaluation indicate that the number of estimated heavy lifts will remain below the specified threshold of 20,000 cycles, the concern remains that similar changes in the operation of the polar cranes may occur in the future that may result in additional lifts and invalidate the current estimates. Describe the tracking mechanisms and/or procedural controls that are in place that may trigger a reevaluation of the estimated heavy lifts, if changes occur in the future operation of the polar cranes.

Response to RAI 5.7.1-1

As described in Section 5.7.1 of Exhibit A of the Application, the original evaluation of crane rail fatigue focused on the polar crane because the number of heavy lifts at or near its rated capacity "bounded" the number of heavy lifts by other cranes. The operation of the ISFSI did not result in reevaluation of the fatigue concerns for the polar cranes. Rather, the operation of the ISFSI and the additional lifts by the spent fuel pool cranes near their rated lifting capacity changed the "bounding" crane for the fatigue analysis from the polar crane to the spent fuel pool crane. For 60 years of operation, the estimated number of cycles at or near rated capacity of the polar crane are less than 200 and the estimated number of cycles at or near rated capacity for the spent fuel pool crane are less than 2000. Both of these estimates are well below the specified threshold of 20,000 cycles in CMAA-70. The maximum estimated number of lifts for the spent fuel pool crane over 60 years of operation is less than 10% of the specified threshold. To obtain 20,000 cycles of heavy load lifts for the spent fuel pool crane would require one lift every 22 hours for 60 years. The cranes would need to operate well outside normal parameters to accumulate 20,000 cycles of heavy load lifts during future operations. No tracking mechanism or procedural controls are needed to manage such a large margin.

ATTACHMENT 2
Oconee License Renewal Project
Application for Renewed Operating Licenses
Responses to NRC Requests for Additional Information (RAI)
NRC Letter Dated October 29, 1998

LIST OF COMMITMENTS

ATTACHMENT 2
Oconee License Renewal Project
Application for Renewed Operating Licenses
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Set #01

LIST OF COMMITMENTS

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

1. Preventive Maintenance Activities will be performed consistent with the descriptions (i.e., activity attributes) provided in the response to RAI 4.3.8-1.

2. A revision to the UFSAR Supplement (Exhibit B of the Application) will be provided by November 30, 1999 to reflect the above commitment.