September 21, 1999

Duke Energy Corporation
ATTN: Mr. W. R. McCollum
Site Vice President
Oconee Nuclear Station
7800 Rochester Highway
Seneca, SC 29672

SUBJECT: NRC INSPECTION REPORT 50-269/99-12, 50-270/99-12, AND 50-287/99-12

Dear Mr. McCollum:

This refers to an inspection conducted on June 2 through July 30, 1999, at the Oconee Nuclear Station. The purpose of the inspection was to determine whether your aging management programs adequately support your application for renewed operating licenses for Oconee. The scope of the inspection included a review of the documentation of your aging management programs and an examination of a sample of plant equipment. The enclosed report presents the results of the inspection.

The inspection revealed that, in most cases, the existing aging management programs were implemented as described in your application. From discussions with plant staff and our review of available documentation concerning your current and future and aging management programs, we verified that your programs were generally consistent with your application. However, the inspection also revealed that current informal aging management programs have minimal procedural guidance and were not always conducted at the specified frequency. In addition, some of the aging management programs described in your application have not been developed, thus we were unable to verify implementation of the programs.

In addition, you concluded in your application that no aging management programs were needed for electrical equipment. However, based on our sample of electrical cable inspection results and our review of potential problem reports, we were unable to conclude that no aging management program is warranted for electrical cables and connectors.

Within the scope of the inspection, violations or deviations were not identified. In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Sincerely,

**Original signed by Victor M. McCree**

Victor M. McCree, Deputy Director
Division of Reactor Safety

Docket Nos. 50-269, 50-270, 50-287
License Nos. DPR-38, DPR-47, DPR-55

Enclosure: NRC Inspection Report

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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|---|---|
| Docket Nos: | 50-269, 50-270, 50-287 |
| License Nos: | DPR-38, DPR-47, DPR-55 |
| Report Nos: | 50-269/99-12, 50-270/99-12, 50-287/99-12 |
| Licensee: | Duke Energy Corporation |
| Facility: | Oconee Nuclear Station, Units 1, 2, and 3 |
| Location: | 7800 Rochester Highway<br>Seneca, SC 29672 |
| Dates: | June 2 - July 30, 1999 |
| Inspectors: | B. Crowley, Reactor Inspector, RII<br>E. Girard, Reactor Inspector, RII<br>G. MacDonald, Reactor Inspector, RII<br>M. Modes, Reactor Inspector, RI<br>R. Prato, Mechanical Engineer, NRR<br>K. Shaukat, Structural Engineer, RES<br>P. Shemanski, Sr. Electrical Engineer, NRR |
| Approved by: | Caudle Julian<br>Team Leader<br>Division of Reactor Safety |

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3

NRC Inspection Report 50-269/99-12, 50-270/99-12, and 50-287/99-12

This special team inspection included a review of the documentation of your aging management programs and an examination of a sample of plant equipment that support Duke Energy's application for renewed operating licenses for the Oconee units.

- The inspectors toured the intake structure, portions of the auxiliary building, tendon gallery and reactor buildings. The team found the mechanical systems to be well maintained and in generally good material condition. However, the team observed external corrosion on the carbon steel Low Pressure Service Water piping inside the Unit 1 reactor building. (Section E8.1)

- The team noted that the applicant identified a number of existing programs to accomplish the aging management program requirements of the Oconee License Renewal Application (LRA). The applicant's plans to expand existing programs and develop new programs are appropriate to accomplish future aging management on the selected systems. (Section E8.2)

- The team verified that the aging management programs for civil structures were conducted in a thorough manner as described in the LRA. However in the past these inspections have not always been completed within the specified time frame. (Section E8.2)

- The team verified that the applicant had implemented the existing mechanical aging management programs as described in the Oconee LRA. However, the inspection revealed that the existing programs have minimal procedural guidance and were not always conducted at the specified frequency. (Section E8.3.2)

- The team determined that some aging management programs described in the LRA have not been developed. The team expressed concern that there was no program or tracking mechanism in place to ensure the development and implementation of these programs. The team found several instances where the scope or content of existing programs had been changed from that described in the License Renewal Application. (Section E8.3.2)

- The Oconee LRA concluded that no aging management programs were needed for electrical equipment. However, based on a sample of electrical cable inspection results and potential problem reports, the team could not agree with the applicant's conclusion that no aging management program is needed for electrical cables and connectors. (Section E8.4)

- As described in NRC Inspection Report 99-11, the team identified three cable types that were not included in the Oconee cable drawings which the license renewal documentation said were used to form the basis for the population of cable/insulation material selected for the aging management review. The applicant subsequently performed a data search and found fourteen additional cable types with four new insulation materials that were not previously considered for aging effects. (Section E8.9)

Report Details

**LICENSE RENEWAL INSPECTION REPORT 99-12**

## III. Engineering

### E8 Miscellaneous Engineering Issues

E8.1 Visual examination of plant equipment

a. Inspection Scope (71002)

In June 1999, during the Unit 1 Cycle 1OEC18 outage, a series of inspectors from the team performed walkdown inspections of accessible portions of several plant systems inside the Reactor Building. The objective was to determine the condition of plant equipment that is inaccessible during plant operation through visual examination.
Portions of these same systems outside the Reactor Building were examined during the inspection documented in NRC Inspection Report No. 50-269,270,287/99-11. However, all three Oconee units were operating during that inspection and portions of the systems inside the reactor buildings were not accessible for observation.

b. Observations and Findings

During the Unit 1 Cycle 1OEC18 outage, an inspector performed visual (walkdown) inspections of accessible portions of the following systems inside the Reactor Building:

Reactor Coolant (RCS)
Core Flood (CF)
Reactor Building Spray (BS)
Component Cooling (CC)
Low Pressure Service Water (LPSW)
High Pressure Injection (HPI)
Feedwater (FW)

The material condition of the piping and components observed in these systems was good. In general, the equipment was clean with no evidence of system leakage; however, the following two conditions were noted:

A significant buildup of corrosion was observed on the un-insulated carbon steel LPSW piping and valves inside the Reactor Building. The applicant had previously removed insulation from a large portion of the LPSW piping and valves inside the Reactor Building because of the potential for the originally installed fiberglass insulation to clog the emergency sump during a Loss Of Coolant Accident (LOCA). During operations, moisture forms on the un-insulated piping due to the temperature differential between the cool piping and the high ambient temperature in the reactor building atmosphere. Over time the moisture has contributed to significant corrosion of the carbon steel piping. Discussions with the resident inspectors and licensee personnel revealed that, when the insulation was initially removed from the LPSW piping, some corrosion had already occurred under the insulation. Removal of the insulation has probably accelerated the corrosion process. The inspector questioned the applicant relative to evaluation of the corroded pipe to determine if the minimum wall thickness had been affected.

The applicant provided a copy of a previously generated Problem Investigation Process (PIP) Report 0-O97-0380, which addressed the insulation problem and the possibility of coating and re-insulating with an anti-moisture insulation. The corrective action listed in the PIP was to replace the LPSW piping inside the shield wall with stainless steel (scheduled for outages 1EOC18 for Unit 1, 2EOC17 for Unit 2 and 3OEC17 for Unit 3). The PIP did not identify the proposed final resolution for the portions of the LPSW piping that remains insulated. Based on discussions with applicant personnel, one train of Unit 3 piping inside the shield wall was replaced during outage 3OEC17 and all other replacements had been delayed until future outages. The PIP did not address interim corrective actions for the corrosion problem until the piping is replaced. After questioning by the inspectors, the applicant revised the PIP to address the corrosion problem.

The inspectors continued to review this issue during the week of inspection ending July 30, 1999. Based on the fact that no decision has been made relative to corrective actions for the insulated piping outside the shield walls, replacement of un-insulated piping inside the shield walls with stainless steel has been delayed, the inspectors questioned whether interim measures are needed for this corrosion problem. In response to the questions raised by the inspector during the inspection of June 2-4, the applicant had cleaned and measured the wall thickness at 7 locations on the un-insulated Unit 1 LPSW piping. Thickness data was evaluated using the Service Water Piping Corrosion Program criteria, which requires component specific analysis if any inspection point is found to be less than 67% of nominal wall thickness. One inspection point at the inspection location just downstream of valve LPSW-10 was found to be 0.133" thick, or less than 67% of the nominal wall thickness of 0.237". The applicant stated that an engineering review determined this condition to be acceptable. However, the applicant was not able to produce a documented analysis by the end of this inspection. All other thickness measurement results met the criteria in the Service Water Piping Corrosion Program. The NRC will examine the documented engineering review and continue to follow the applicant's resolution of the LPSW piping corrosion issue during future inspections. (Inspection Followup Item 50-269/99-12-01)

As for aging management of the LPSW system carbon steel piping, the applicant credits its Service Water Piping Corrosion Program (the program for control of loss of material) for mitigating internal corrosion problems, and its Inspection Program for Civil Engineering Structures and Components for managing the effects of external corrosion of piping. However, as identified in the LRA, this program does not presently cover piping and the inspection interval is 5 years. The applicant plans to revise the program to include the external visual inspection of piping, but an aging management program for external corrosion of piping does not yet exist.

- Corrosion buildup was noted on the reactor coolant piping LOCA restraint structural steel and bolting below the 1B1 and 1B2 RC pumps. The applicant indicated that the corrosion was caused by previous leaks of borated water from RCS System temperature sensors located above the restraints. The sensors have been modified and no longer leak. Applicant personnel had previously evaluated the condition and determined that it did not affect the integrity of the structural steel and bolting. However, the corrosion had not been removed to determine if wastage of the bolting has occurred. After questioning by the inspector, on June 6, 1999 the applicant initiated Work Order 98168066, to remove the corrosion, verify no structural damage has occurred, and re-coat the material.

In addition to conducting inspections, the inspector observed in progress inservice inspection (ISI) (liquid penetrant and ultrasonic examinations) of High Pressure Injection System Weld 1HP-180-97E. The examinations were performed by knowledgeable and qualified personnel in accordance with the 1989 Edition of ASME Section XI and the applicant's ISI plan, Third Interval Inservice Plan Oconee Nuclear Station Unit 1, Revision 4.

The inspector also observed in progress Erosion/Corrosion inspection (ultrasonic measurement for wall thinning), including grid layout, of Feedwater System Elbow 1FDW60. The Erosion/Corrosion Program is the aging management program referenced in the applicant's License Renewal Application for control of pipe wall thinning in the Feedwater System. The inspection was performed by knowledgeable and qualified personnel in accordance with the applicant's Erosion/Corrosion Program and no significant wall thinning of the elbow was identified.

On June 8-9, 1999 another team inspector conducted walkdowns of the high pressure injection, emergency feedwater, feedwater, and makeup systems to identify any visually evident aging effects. The inspector did not observe any significant evidence of aging during these walkdowns except that the steam generator emergency feedwater ring header to nozzle flange bolting was heavily rusted. This condition was identified to the applicant. The inspector was subsequently informed that an applicant engineer inspected the bolting and determined the condition was acceptable. These joints will be refurbished during upcoming steam generator replacements so the NRC found the interim condition acceptable.

External to the Reactor Building, on June 8-9, 1999, the inspector observed applicant engineers conducting inspections of the condition of the Condenser Circulating Water (CCW) intake piping. This inspection is part of the licensee's aging management program for the CCW system. The inspector concluded that the program provided a thorough inspection of the intake piping and the portion of the piping observed by the inspector was in good condition. The inspection was to be documented in Calculation OSC 7380.

During the week of July 12, 1999, the inspectors, concentrating on structural aging, toured several areas with applicant engineers to evaluate the condition of the structures. The inspectors conducted walkdowns of the intake structure, portions of the auxiliary building for all three units, the exterior of the reactor buildings, and the Unit 2 reactor building tendon gallery. The structures were found to be in acceptable condition.

On June 21-23, two other team inspectors conducted walkdowns of the Unit 1 Reactor Building, to examine the condition of electrical equipment. The following is a summary of the inspectors' observations:

- Cables in the area above and adjacent to the reactor core that supplied power to the fuel handling bridge exhibited damage. Cabling in this area is subject to insulation material degradation from thermal and radiation embrittlement, and mechanical damage from the flexing of the cables. One set of cables was framed inside a track that limits the radius of the bend experienced by the cable with the movement of the bridge. The second set was suspended cable anchored to the top of the bridge at a number of points. The suspended cable would provide the slack needed to allow the bridge to travel along its fixed path. The track cable was severely damaged and was being replaced by the applicant. The suspended cable was in good condition, but had been replaced in recent years. Nonetheless, these cables had been exposed to environmental and mechanical aging that may affect the cables' ability to function. Other cables in the vicinity of the reactor core appear to be exposed to similar thermal and radiation environments. Because thermal and radiation embrittlement of cabling is apparently occurring in the area above and next to the core, the cabling in this area, especially those that are subject to movement, require condition monitoring. This concern is compounded by the fact that the cabling in this area is encased in metal flex or braided conduit and any cracking can not easily be observed.

  During the walkdown of the reactor building, in an area where feedwater piping penetrates the containment wall, the inspectors noted what appeared to be accelerated aging of cabling as a result of heat being emitted from the feedwater piping. A cable tray carrying numerous cables crosses closely over the hot feedwater piping. The inspectors discussed this observation with applicant personnel who indicated that they were aware of this issue and acknowledged the need for corrective actions including possible future replacement of the cabling.

- During the walkdown of the Reactor Building, rust was noted on flex-conduit and braided metal jacketing of cables. The applicant explained that this rust was primarily from contact with boric acid. Although the protective metal jackets were used primarily to protect the cable from damage during installation, the potential effects from boric acid on underlying cable insulation could not be observed. The inspectors raised questions with the applicant about the effects of boric acid on the integrity of the cable insulation.

The inspectors also walked down the Turbine Building. The inspectors observed the inside of an electrical panel containing cabling, connectors, and terminal blocks. No ongoing degradation was observed. In addition, during the License Renewal Demonstration Program, the applicant noted a potential problem with floor wax and wax strippers getting on cabling and causing aging due to chemical stressors. The inspectors also observed these conditions in the turbine building.

c. Conclusions

The team inspections found the mechanical systems to be well maintained and in generally good condition. The team observed external corrosion on the carbon steel Low Pressure Service Water piping inside the reactor building. The team also observed in the Reactor Building degraded cabling where they have been subject to mechanical movement, thermal and radiation embrittlement, and boric acid exposure.

The inspectors toured the intake structure, portions of the auxiliary building, tendon gallery, exterior of the reactor buildings, and the turbine building. The structures were found to be in acceptable condition.

## E8.2 Review of Aging Management Programs for Selected Systems

a. Inspection Scope (71002)

The inspectors reviewed aging management programs for selected plant systems as described below to verify that the program requirements were identified and implemented for the selected systems consistent with the Oconee License Renewal Application (LRA) and the NRC Safety Evaluation Report (SER) dated June 1999.

b. Observations and Findings

E8.2.1 Reactor Building Spray System

For the Reactor Building Spray System, the LRA identified two aging management programs. The existing Chemistry Control program was identified for managing the effect of loss of material in the borated water environment. The planned Reactor Building Spray System Inspection was identified for managing the effects of loss of material and cracking in normally dry stainless steel piping in an air environment after being exposed to borated water and then dried.

The Reactor Building Spray Inspection is a new program that the applicant plans to develop specifically for the Reactor Building Spray System. The applicant plans to develop and implement the program after issuance of the renewed operating license. Therefore, the inspectors were unable to evaluate the adequacy of this program.

The inspectors reviewed the chemistry program and found that it had been implemented for the Reactor Building Spray System as specified in the LRA. Chemistry Manual 3.10 addressed chemistry control for the Borated Water Storage Tank which is the water supply for the Reactor Building Spray System. In addition to review of the Chemistry Manual requirements for the system, the inspectors reviewed a sample of chemistry data from May 1998 to July 1999 for the Borated Water Storage Tank and found that the program had been implemented in accordance with program requirements.

Section E8.3.2.I and h below further describe the results of review of these two aging management programs.

E8.2.2 Component Cooling System

For the Component Cooling System, the LRA identified four aging management programs as follows: 1) the existing Plant Chemistry Control Program was identified for managing the effect of loss of material in carbon steel components exposed to a treated water environment , 2) the planned Treated Water Systems Stainless Steel Inspection was identified for managing the effect of cracking in stainless steel components exposed to a treated water environment, 3) the Boric Acid Wastage Surveillance Program was identified for managing loss of material to the external surfaces of carbon steel components due to boric acid wastage in the Reactor Building environment and a sheltered environment (the Auxiliary Building), and 4) the Inspection Program for Civil Engineering Structures and Components was identified for managing loss of material on external surfaces of carbon steel components due to general corrosion and galvanic corrosion in the Reactor Building environment and in a sheltered environment (the Auxiliary Building) .

The inspectors reviewed the chemistry program and found that it had been implemented for the Component Cooling system as specified in the LRA. Chemistry Manual 3.10 addressed chemistry control for the Component Cooling System as specified in the LRA. In addition to reviewing the Chemistry Manual requirements for the system, the team reviewed a sample of chemistry data from June 2 to July 8, 1999, and found that the program was being implemented in accordance with program requirements.

The Treated Water Systems Stainless Steel Inspection is a new program to characterize the loss of material due to pitting corrosion and cracking caused by stress corrosion of stainless steel components. The applicant plans to formally issue and implement the program after issuance of the renewed operating license. Therefore, this program could not be fully evaluated by the inspectors for content and implementation.

The Boric Acid Wastage Program was reviewed. Although not system specific, the program provided instructions for identifying and evaluating boric acid leakage for all systems, which would include the Component Cooling system. This program is discussed further in Section E8.3.2.f of this report.

The Inspection Program for Civil Engineering Structures and Components is an existing program, but presently does not cover inspection of piping components. The applicant plans to enhance the program to cover mechanical system components. Because the program did not cover mechanical components, the inspectors could not fully evaluate the program for content and implementation. This program is discussed further in Section E8.3.1.b.

E8.2.3 Low Pressure Service Water System (LPSW)

For the LPSW System, the LRA identified the following six aging management programs as follows: 1) the existing Service Water Piping Corrosion Program was identified for managing the effect of loss of material due to general corrosion and microbiological corrosion in components exposed to a raw water environment, 2) System Performance Testing Activities were identified for managing the effect of fouling for components exposed to raw water, 3) the planned Galvanic Susceptibility Inspection was identified for managing the effect of loss of material due to galvanic corrosion in components exposed to raw water, 4) Preventive Maintenance (PM) activities (eddy current inspection of heat exchanger tubes) was identified for managing the effects of loss of material for component cooler tubes exposed to raw water, 5) the Boric Acid Wastage Surveillance Program was identified for managing loss of material to the external surfaces of carbon steel components due to boric acid wastage in the Reactor Building environment and in a sheltered environment (the Auxiliary Building), and 6) the Inspection Program for Civil Engineering Structures and Components was identified for managing loss of material on external surfaces of carbon steel components due to general corrosion and galvanic corrosion in the Reactor Building environment and a sheltered environment (the Auxiliary Building) .

The inspectors reviewed the Service Water Piping Corrosion Program, Revision 1, dated November 1, 1995, and discussed the program with responsible applicant personnel to verify that the program covered the LPSW System and had been implemented. The program had been implemented for the LPSW System and required periodic Ultrasonic (UT) thickness inspections of 9 selected locations in the LPSW System for each Unit. A summary of all UT inspection data for the LPSW inspection locations was reviewed. In addition, detailed UT data was reviewed for inspection locations C1CCW001(1990 and 1995), C1LPSW002 (1990 and 1995), C1LPSWW004 (1990 and 1995), C1LPSW006 (1990 and 1995), and C2CCW002 (1991) and found to meet program requirements with minimal wall loss identified. Although weaknesses were identified in the Service Water Piping Corrosion Program (see Section E8.3.2.n below), the inspectors concluded that the program had been implemented for the LPSW system consistent with the LRA.

For System Performance Testing Activities, the inspectors reviewed the following data and discussed the performance testing activities for the LPSW System with the System Engineer and other responsible applicant personnel to verify that performance testing had been implemented for the system:

Calculation OSC-4488, Revision 5, which documents the historical flow data for the LPSW pumps 3A and 3B supply piping; 3A and 3B LPSW Strainers; 3A , 3B and 3C Reactor Building Cooling Units; Unit 3 Reactor Building Auxiliary Coolers; Low Pressure Injection Coolers 3A and 3B; Flow Control Valves 3LPSW251 and 3LPSW252; Unit 3 Component Coolers; and Unit 3 RC pump motor cooling piping.

Completed Quarterly Test Performance Procedure PT/1/A/0600/012 - performed 10/26/98 and 4/21/99 - test verified LPSW flow to Turbine Driven Emergency Feedwater Pump

Completed Quarterly Test Performance Procedure PT/1/A/0600/013 - performed 3/29/99 - test verified LPSW flow to Motor Driven Emergency Feedwater Pump

Completed Quarterly Test Performance Procedure PT/1/A/0230/015 - performed 5/18/98 - test verified LPSW flow to High Pressure Injection Motor Bearing Cooler

Completed Outage Test Performance Procedure PT/2/A/0251/023 - performed 5/7/98 - test verified LPSW flow conditions

System Engineer's Pump Flow Trend Data for LPSW Pumps 3A and 3B

System Engineer's High Pressure Injection Pump Motor Cooler Trends for Pumps 3A, 3B, and 3C

The inspectors verified that System Performance Testing for the LPSW to manage the effects of fouling in the system had been implemented as described in the LRA and the NRC SER.

The Galvanic Susceptibility Inspection is a new planned program to characterize the loss of material due to galvanic corrosion in carbon steel and stainless steel components. The applicant plans to develop and implement the program after issuance of the renewed operating license. Therefore, the inspectors were unable to evaluate the content and implementation of this program. The Program is discussed further in Section E8.3.2.i.

The Preventive Maintenance (PM) Program (Eddy Current testing) for the Component Cooler Tubes was reviewed as described in Section E8.3.2.p.3. In addition, the inspectors reviewed a sample of eddy current test results for Coolers 3A and 3B, performed in November 1993, and Coolers 1B and 2A, performed June 1995, which did not show significant degradation of the tubes. The inspectors verified that the PM program for the Component Coolers had been implemented consistent with the LRA.

The Boric Acid Wastage Surveillance Program was reviewed. Although the Component Cooling System was not specifically mentioned, the program provided instructions for identifying and evaluating boric acid leakage for all systems. The Program is further discussed in Section E8.3.2.f.

The Inspection Program for Civil Engineering Structures and Components is an existing program, but currently does not cover inspection of piping components. The applicant plans to enhance the program to cover mechanical system components. Because the program did not cover mechanical components, the inspectors could not fully evaluate the program for content and implementation.

E8.2.4 Emergency Feedwater System (EFW) System

The LRA identified the existing Chemistry Control Program as the aging management program for minimizing corrosion in the EFW System. This program provides chemical parameter limits to minimize corrosion. The LRA noted that the EFW chemical parameter limits were specified in the secondary water chemistry specifications of the Chemistry Control Program. These specifications apply to several systems and contain limits that vary based on vendor and industry recommendations and on sampling location.

The LRA described the overall secondary water chemistry specifications and indicated that oxygen, sodium, chloride, silica, and sulfate levels would be monitored. It did not specifically describe the type of monitoring performed for EFW, other than to indicate samples would be taken from the condense hotwell. The inspectors found that the secondary water chemistry specifications were contained in Chemistry Manual. The inspectors determined that the specifications were generally consistent with the program described in the LRA and the NRC SER. However, the team noted that the manual required $O_2$ and NA to be monitored, but did not require chloride, silica, and sulfate levels to be monitored in the condenser hotwell. Applicant personnel indicated that monitoring $O_2$ and NA was considered acceptable, particularly because Feedwater chemistry, which was monitored for all of the subject parameters, was considered a more appropriate aging management tool for EFW. Further, they stated that the LRA would be changed to indicate for EFW, in place of the hotwell, in the next revision.

The team reviewed hotwell and final feedwater trend data for the period of January to June 1999, and verified that the EFW chemistry limits were being implemented in accordance with Chemistry Manual 3.8.

E8.2.5 Feedwater System

The LRA identified the Chemistry Control Program and the Piping Erosion/Corrosion Program as the two aging management programs for minimizing corrosion in the Feedwater System. The Chemistry Control Program provides chemical parameter requirements to minimize corrosion, while the Piping Erosion/Corrosion Program provides for examinations at selected locations to detect wall thinning. The Chemistry Control Program is discussed in Sections E8.2.4 and E8.3.2h. The Piping Erosion/Corrosion Program is discussed elsewhere in section E8.3.2.8.

E8.2.6 High Pressure Injection System (HPI)

The LRA identified two aging management programs for the corrosion and cracking in this system's internal borated water operating environment; the Chemistry Control Program and the Reactor Coolant System Operational Leakage Program. The Chemistry Control Program provides chemical parameter requirements to minimize corrosion and the Leakage Program provides for detecting leakage as an indicator of a loss of pressure boundary integrity.

The Chemistry Control Program is discussed in section E.8.3.2.h. The primary water specifications of the Chemistry Control Program also apply to HPI. Which are described in section 3.10, of the applicants Chemistry Manual. The inspectors verified that the requirements specified in this manual were consistent with the program described in the

LRA and the NRC SER. Through a review of trended Reactor Coolant chemical parameters described in Section E8.3.2.h, the inspectors verified that the program was implemented as described in the LRA and the NRC SER.

The Reactor Coolant System Operational Leakage Program is discussed in Section E8.3.2.b as a Program for managing aging in the Reactor Coolant System. The inspectors verified implementation of the program as described therein.

E8.2.7 Standby Shutdown Facility Reactor Coolant Makeup System (RCM)

The LRA identifies the existing Chemistry Control Program as the aging management program for the corrosion in this system's internal borated water operating environment. This program, which is described in Section E8.3.2.h, provides chemical parameter limits to minimize corrosion. The LRA noted that the RCM chemical parameter limits were specified in the primary water chemistry specifications of the Chemistry Control Program. These specifications are described in the applicant's Chemistry Manual, 3.10. The requirements specified by this manual for the RCM were consistent with the program described in the LRA and evaluated by the NRC SER. RCM chemistry samples are taken from Spent Fuel Pool, which is the source of RCM water. The inspectors verified implementation through the review of trended Spent Fuel Pool water chemical parameters.

E8.2.8 Keowee Service Water System

For the Keowee Hydro Station, the fire protection system is part of the Keowee Service Water System. The only portion of the Keowee Service Water System in license renewal scope is the fire protection portion. For the Keowee Service Water System, the LRA identified five aging management programs as follows: 1) the existing Service water Piping Corrosion Program was identified for managing the effect of loss of material components exposed to raw water, 2) the Fire Protection Program was identified for managing the effect of fouling for components exposed to raw water and loss of material for components exposed to an air environment, 3) the planned Galvanic Susceptibility Inspection was identified for managing the effect of loss of material due to galvanic corrosion in components exposed to raw water, 4) the planned Cast Iron Selective Leaching Inspection was identified for managing the effect of loss of material due to selective leaching of cast iron components exposed to raw water, and 5) the existing Inspection Program for Civil Engineering Structures and Components was identified for managing loss of material on external surfaces of carbon steel components due to general corrosion of carbon steel components in a sheltered environment.

The Service water Piping Corrosion Program is an existing program, but does not include any inspection points for Keowee piping systems. The licensee plans to add inspection points to the Service Water Piping Corrosion Program for Keowee components after issuance of the renewed license. The inspectors reviewed the existing Service Water Corrosion Program and a sample of inspection data for the program, as described in Section E.8.3.2.n. The applicant has implemented the program, however, the program does not include inspection points for Keowee systems. Therefore, the team was unable to fully evaluate the content and implantation of the program for Keowee systems.

The inspectors reviewed the Fire Protection Program and found that it addresses fouling (raw water environment) and loss of material (air environment) for the Keowee Service Water System. In addition, the inspectors reviewed the following completed performance test and maintenance procedures, which document inspection and testing of the fire protection portion of the service water system: 1) PT/0/A/2200/012, performed 3/11/97, 3/10/98, and 3/17/99 - which documents the annual performance of the fire protection pump and Mulsifyre Systems wet surveillance; 2) PT/0/A/2200/010, performed 5/12/99, 4/14/99, and 6/7/99 - which documents the monthly fire protection equipment surveillance; and 3) MP/0/A/1705/037, performed 7/26/1999 - which documents the three year fire protection strainer removal cleaning, and re-installation. The applicant plans to enhance the program to stroke and flush the fire hydrants in the system. The team notified that the Fire Protection Program was implemented for the Keowee Service Water System consistent with the LRA and the NRC SER.

The Galvanic Susceptibility Inspection and the Cast Iron Selective Leaching Inspection are new planned programs to characterize the loss of material due to galvanic corrosion in carbon steel and cast iron components and selective leaching in cast iron components. The applicant plans to develop and implement these programs after issuance of the renewed operating license. Therefore, the team was unable to evaluate the content and implementation of this program.

The Inspection Program for Civil Engineering Structures and Components is an existing program, but presently does not cover inspection of piping components. The applicant plans to enhance the program to cover mechanical system components. Because the program did not cover mechanical components, the team could not fully evaluate the program for content and implementation.

E.8.2.9 Keowee Governor Oil System

For the Keowee Governor Oil System, the LRA identified two aging management programs: the existing Keowee Oil Sampling Program and the existing Inspection Program for Civil Engineering Structures and Components .

The oil sampling program was an existing informal program used to manage the effect of loss of material in components exposed to an oil environment. This program was identified in the LRA as a new program to be implemented after issuance of the renewed license. Therefore, the inspectors were unable to fully evaluate the content and implementation of the program for this system. The program is discussed in more detail in Section E8.3.2.r.

The Inspection Program for Civil Engineering Structures and Components is an existing program used for managing loss of material on external surfaces of carbon steel components due to general corrosion of carbon steel components in a sheltered environment. The program does not cover inspection of piping components. The applicant plans to enhance the program to cover mechanical system components. Because the program did not cover mechanical components, the team was unable to fully evaluate the content and implementation of the program for this system.

E.8.2.10 Keowee Turbine Generator Cooling Water System

The LRA identified four aging management programs for the potential corrosion and fouling caused by this system's internal raw water operating environment. The programs and their implementation are described below:

The LRA identified the existing Service Water Piping Corrosion Program for managing general corrosion of the system piping. However, the current program did not include inspection of the Keowee raw water piping. The LRA indicated that the program would be enhanced to include Keowee piping locations, focusing on brass and bronze piping. The team reviewed the applicants Specification OSS-0274.00-0005 which described the proposed enhanced inspection and provided a tabulation of its attributes. The specification indicated that sample points in the Keowee Turbine Generator Cooling Water System would be added to the program before the end of the current licensing period. The inspectors verified that the description of the program in the specification was consistent with the LRA and the NRC SER, however, the team was unable to fully evaluate the implementation of this program for this system.

The LRA identified the planned Galvanic Susceptibility Inspection for managing localized material loss due to galvanic corrosion of the system's carbon steel components. This inspection program, which the applicant has not yet developed, is characterized as a one-time inspection. The LRA indicates that the inspection will be completed following issuance of the license extension, and prior to February 6, 2013. Therefore, the team was unable to evaluate this program for content and implementation.

The LRA stated that fouling caused by raw water would be managed through the Performance Testing Program. The team found that the applicant described the program and provided a tabulation of its attributes in Specification OSS-0274.00-0005. The program is described further in Section E8.3.2.u.

The LRA indicated that existing Preventive Maintenance Program activities would be used to manage corrosion of Keowee Turbine Generator Cooling Water System strainers. The attributes of these activities, as applied to the strainers, were described in the applicant's response to NRC RAI 4.3.8-1 and in Specification OSS-0274.00-0005. The inspectors verified that description of the program in the specification was consistent with the LRA and the NRC SER. This program is described further in Section E8.3.2.v.

E8.2.11 Keowee Carbon Dioxide System

The LRA identified the Keowee Air and Gas Systems as the aging management program for corrosion in this system's internal carbon dioxide operating environment. The team determined that the inspection of the Keowee Carbon Dioxide System had not been implemented. The applicant described this one-time inspection in Specification OSS-0274.00-0005. The inspectors verified that the description in the specification was consistent with the LRA and the NRC SER. The LRA indicates that the inspection will be completed following issuance of the license extension, and prior to February 6, 2013. This program is further discussed in Section E8.3.2.t.

E.8.2.12 Keowee Governor Air System

The LRA identified one aging management program for the corrosion in this system's internal air operating environment, the Keowee Air and Gas Systems Inspection. This was described as a planned, new, one-time inspection of portions of Governor Air tanks and pipe to assess the loss of material due to general corrosion. The inspectors found that the applicant described the inspection and provided a tabulation of its attributes in Specification OSS-0274.00-0005. The description in the specification was consistent with the LRA and the NRC SER. This program is further discussed in Section E8.3.2.t.

Review of Work History

The inspectors reviewed equipment work history summaries for the last several years for the following systems to identify evidence of equipment aging that were not being addressed by the applicant's aging management programs: Reactor Building Spray, Component Cooling, Low Pressure Service Water, Feedwater, Emergency Feedwater, High Pressure Injection, Standby Shutdown Facility Makeup, Keowee Governor Oil, Keowee Service Water, Keowee Governor Air, Keowee Carbon Dioxide, and Keowee Turbine Generator Cooling Water. The review revealed no evidence of aging of the passive components.

c. <u>Conclusions</u>

With regard to the specific systems addressed, the team concluded that existing programs had been implemented consistent with the LRA and the NRC SER to accomplish aging management. The applicant's plans to expand existing programs and develop new programs are appropriate to accomplish future aging management on the selected systems.

E8.3 <u>Review of Selected Aging Management Programs</u>

a. <u>Inspection Scope (71002)</u>

The inspectors reviewed selected aging management programs, in the areas of civil engineering structures, and components, mechanical aging and preventive maintenance, to verify that the existing programs were implemented consistent with the information presented in the applicant's LRA, applicant programs and procedures, and the NRC SER. Where existing applicant programs will be expanded or new aging management programs will be created to support the LRA, the inspector examined available documentation and discussed future plans with applicant engineers.

b. Observations and Findings

E8.3.1 Review of Civil/Structural Aging Management Programs

The inspectors examined documents that describe existing and planned inspection programs for managing the aging of civil engineering structures and components. The following programs were examined by reviewing existing procedures and past inspection data where and discussing the programs with responsible applicant engineers.

E8.3.1.a Coatings Program

The coatings program for safety related structures is described by the Nuclear Coating Maintenance Manual while the non-safety related program is described in the Field Coating Maintenance Manual. Based on a reviewed of these documents and discussion with the applicant engineer, the team verified that this previously existing program was implemented as described in the LRA.

E8.3.1.b Inspection Program for Civil Engineering Structures and Components

Although this is an existing program, the applicant has not established a procedure that implements the program as a formal aging management activity. Based on discussions with the applicant, Procedure EDM-410, “Program for Monitoring Civil Structures”, will be expanded in the future to include inspections for loss of material for the external surfaces of mechanical components. The team reviewed the results of previous inspections conducted by the applicant using EDM-40 and determined that the results were acceptable. However, the inspections were not always completed in the specified time frame.

Inspectors reviewed documented results of past inspections. The program has not always met the intended 5-year frequency. A complete inspection was done in 1984. Another was begun in 1989 but not completed through 1992, so a memo to file was prepared to document the incompletion. A comprehensive inspection was done in 1997 and another is planned for 2002. Documentation of results were acceptable and becoming more complete with time. The inspectors concluded that the applicant plans for formalizing and expanding this program are consistent with their description in the LRA.

E8.3.1.c Tendon – Secondary Shield Wall – Surveillance Program

This program is described in Section 4.28, of the LRA as an existing program used to inspect a sample of the tendons which support and strengthen the removable secondary shield wall inside the Reactor Building. The team discussed the program with applicant engineers who indicated that the practice of inspecting tendons every other outage had been reduced to 3 tendons. The responsible engineer indicated that this change was based on industry acceptance of leak-before-break accident analysis methodology and the applicant’s belief that the postulated LOCA loads impacting the shield wall would be smaller than originally postulated.

Section 4.28 of the applicant’s LRA indicates that “A random sample of tendons (including vertical) are inspected every other refueling outage and lift-off tests are performed on a selected number of tendons.” In its response to a Request for Additional Information dated

February 8, 1999, the applicant revised the statement as follows: “Testing is performed every other refueling outage on at least ten randomly selected tendons for each unit which is approximately 14% of the tendons in scope for each unit.”

Based on this information the team concluded that the reduction in the scope of this program was inconsistent with the LRA. The team also expressed concern that there was currently no management program or tracking mechanism in place to ensure the development and implementation of proposed aging management programs, as described in the LRA.

E8.3.1.d Containment Inservice Inspection Program

The inspectors reviewed previous Containment Inservice inspection results from Reactor Building Civil Inspections performed on Unit 1, 1/12/93, Unit 2 6/8/93 and Unit 3 11/12/96 in support of Appendix J Reactor Building leak rate tests. The inspection records appeared acceptable. The NRC amended 10 CFR 50.55a to incorporate by reference the ASME Boiler and Pressure Vessel Code, Section XI subsections IWE and IWL 1992 addition with the 1992 addenda with certain modifications. The applicant is currently developing this program to be implemented by September 9, 2001. However, the team was unable to evaluate the content and implementation of the modified program.

E8.3.1.3.e Five-year Underwater Inspection of Dams

This applicant voluntary program involves underwater inspection of all lake dams. The inspector was told it was done in 1993. They skipped 1998 but plan to do one in August 1999.

E8.3.1.f FERC Five-year Inspection Program

This inspection required by 18 CFR causes Duke to have an independent consultant perform an inspection of the lake dams. The inspectors reviewed consultant reports from 1991 and 1996 and found them comprehensive and acceptable.

E8.3.1.g Keowee Penstock Inspection Program

This program is described in section 4.20 of the LRA as an existing program. It states that visual inspections are performed of the interior surface of the Keowee Penstock (i.e., water intake structure) at least every five years when the penstock is dewatered during outages.

E8.3.2 Review of Mechanical Aging Management Programs

E8.3.2.a Reactor Vessel Internals

The reactor vessel internals are located within the reactor vessel and are divided into two major structural sub-assemblies; the plenum assembly and the core support assembly. The core support assembly is further divided into the core support shield assembly, the core barrel assembly and the lower internals assembly.

The applicant established the scope of the reactor vessel internal components requiring aging management, the intended function of the component, and the applicable aging affect. The scope, function, and aging affect for the reactor vessel internal component was then compared against the scope, function, and aging affect established in the Babcock and Wilcox's Owner Group Topical Report BAW-2248, "Demonstration of the Management of Aging Affects for the Reactor Vessel Internals". The results of the comparison were reported in Oconee's application in OLRP-1001, Sections 2.4 and 3.4. The applicant intends to use the methods described in this topical report as a basis for the aging management program for the reactor vessel internals at Oconee. A separate NRC safety evaluation of BAW-2248 was not completed at the time of this inspection and, therefore, the NRC team was unable to determine the acceptability of this program based on this topical report.

The thermal shield, constructed of austenitic stainless steel, is installed in the annulus between the core barrel cylinder and the reactor vessel inner wall. The FSAR, in 4.5.1.3.2 , paragraph 5, states "the thermal shield reduces the incident gamma absorption internal heat generation in the reactor vessel wall and thereby reduces the resulting thermal stresses". The thermal shield and thermal shield upper restraint were omitted from BAW-2248, however, as stated in the FSAR, they support an Oconee intended function of thermal shielding. The thermal shield and thermal shield upper restraint therefore are included in the Oconee license renewal program in paragraph 3.4.6 of OLRP-1001. The control rod assemblies, fuel assemblies, and the incore monitors are not included in the scope of license renewal.

The aging affects identified for the reactor vessel internals are cracking, loss of material, reduction of fracture toughness, and loss of mechanical closure integrity for bolted connections. All the internal components are affected by these aging mechanisms except the core barrel assembly, which is not affected by a loss of material. In addition, the thermal shield and thermal shield restraint are not affected by a loss of material or loss of closure integrity. The identified aging affects will be managed by the Inservice Inspection Program and a new program for license renewal: Reactor Vessel Internals Aging Management Program.

The existing ISI program, which is carried out in accordance with ASME requirements, performs a VT-3 visual inspection of the accessible surfaces of the internals components. The components must be removed from the vessel in order to perform the inspection. The inspection examines the surfaces for the following effects:

- structural distortion or displacement of parts to the extent that component function may be impaired;

- loose, missing, cracked, or fractured parts, bolting, or fasteners;

- foreign materials or accumulation of corrosion products that could interfere with control rod motion or could result in blockage of coolant flow through fuel;

- corrosion or erosion that reduces the nominal section thickness by more than 5%; wear of mating surfaces that may lead to loss of function; or structural degradation of interior attachments such that the original cross-sectional area is reduced more than 5%.

The existing ISI program may not be able to adequately demonstrate the management of cracking precipitated at lower stress levels due to losses in fracture toughness to the degree required by an aging management program because the visual examination may not be sufficiently refined for this purpose. The Office of Nuclear Reactor Regulation has suggested an augmented visual examination with a resolution of 0.5 mm may be required to adequately manage the affects of embrittlement related cracking. In addition the Inservice Inspection program does not, by itself, address the aging affects of closure integrity or loss of fracture toughness.

The Reactor Vessel Internals Aging Management Program, which may be able to address these deficiencies, does not currently exist. The applicant has proposed, in Volume III, paragraph 4.3.11 of their application that the program "may include" continued characterization to address key program elements to address cracking, reduction of fracture toughness, and loss of closure integrity. Based on this continued characterization the applicant will develop, prior to midnight of February 6, 2013, an "appropriate monitoring and inspection program (which) will provide additional assurance that the reactor vessels internals will remain functional through the period of extended operation." The applicant does not state the minimum technical parameters used to develop the program.

The team made the following observations based in its review: the use of BAW-2248 is indeterminate pending resolution of NRC comments; the ISI program may have to be supplemented to address cracking at lower stresses due to a reduction in fracture toughness; and, the Reactor Vessels Internals Aging Management has not been developed. For these reasons, the team was unable to judge the adequacy of the application in the area of aging management of the reactor vessel internals.

E8.3.2.b Reactor Coolant System Operational Leakage Monitoring

The component joints, making up the reactor coolant system, are fabricated by welding, bolting, rolling, or pressure loading. Valves used to isolate connecting systems from the RCS are considered to be joints for the purpose of monitoring leakage. FSAR 3.1.9, Criterion 9, states the pressure boundary shall be designed and constructed so as to have an exceedingly low probability of gross rupture or significant leakage through out its design lifetime. In order to assure that leakage does not become significant, Oconee Technical Specifications 3.4.13, establishes limits that allow operators to take corrective actions before a leak becomes detrimental to the safety of the public. The safety significance of a leak can vary based on the source, rate, and duration of the leak. The Limiting Condition for Operation (LCO) in 3.4.13, deals with the protection of the reactor coolant pressure boundary from degradation and the core from inadequate cooling. A loss of coolant accident due to a rupture in the coolant system can be prevented by monitoring leakage as shown by an NRC accepted leak-before-break analysis.

Leakage in the RCS is categorized as unidentified or identified. Unidentified leakage is limited to one gallon per minute. Up to 10 gallons per minute of identified leakage is allowed by the LCO. The LCO further states that no pressure boundary leakage is allowed because it is indicative of material deterioration. Leakage past seals, gaskets, and steam generator tubes is not pressure boundary leakage. For the purposes of license renewal, seals and gaskets are renewed regularly and are not part of the application. Steam generator degradation and its leakage from the primary to secondary system is covered separately in the technical specification as leakage through one generator or all generators. Leakage through all generators is limited to 300 gallons per day and the leakage through a single generator is limited to 150 gallons per day.

Identified and unidentified RCS leakage is determined by performance of an RCS water inventory balance. Primary to secondary leakage is measured by effluent monitoring within the secondary systems or comparison of the primary and secondary radioisotope concentrations. These methods provide the necessary sensitivity to confirm that leaks are within the required limits. Additional early warning of leakage is also provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level.

Reactor coolant system leakage monitoring is administratively controlled by procedure PT/1/A/0600/010 “Reactor Coolant Leakage”. The team reviewed Revision 41 of this procedure. The leakage test is performed daily using the Operator Aid Computer or, if it is unavailable, the leakage is calculated manually. If the test shows the leakage rate is greater than 0.5 g.p.m., or has increased by more than 0.25 g.p.m., above the previous calculation, the leakage must be identified using OP/0/B/1106/033 “Primary System Leak Identification”.

The applicant, in Volume III, 4.23.2 “Operating Experience and Demonstration” refers to Licensee Event Reports (LERs) 270-85008, 287-95001, 287-88002, 270-97001, and 269-98002 as examples of cracking, loss of material, and loss of mechanical closure integrity being adequately managed by leak detection. The team reviewed each of the LERs.

LER 270-85008, reports the failure of an instrument root valve packing gland which caused the Oconee Unit 2 to be placed in hot shutdown because the unidentified leak rate was calculated to exceed 1 g.p.m., LER 287-88002, discusses a steam generator leak caused by erosion/corrosion of tube 121-103 and fatigue of tube 77-5 in the steam generator. The steam generators contained identified leakage, which was being monitored, when the rate increased. Shut down was initiated as a consequence of a rise in the off gas monitor of the condensate air ejector. LER 287-95001, reports a packing leak in 3RC-3 pressurizer spray block valve which resulted in an estimated 36 g.p.m., leak as indicated by the letdown storage tank level. The storage tank level is a parameter used in calculating leak rates and is listed in PT/1/A/0600/010 as one of the inputs used when performing a manual leak rate calculation. LER 270-97001 reports a leak caused by a thermal fatigue crack in the safe end to pipe weld on the high pressure injection to RCS cold leg nozzle near reactor coolant pump 2A1. The shut down and notice of unusual event were as a consequence of an increase in excess of 10 g.p.m., in the unidentified leak rate. LER 269-9802, reports an increase in the reactor building normal sump while heating the plant to Hot Shutdown (Mode 4) as a result of a stress corrosion crack located in a weld in the pressurizer surge line drain line.

The NRC team concluded that the reactor coolant system operational leakage monitoring system facilitates adequate management of the identified aging effects in the reactor coolant system. The LERs listed in the applicants submittal demonstrate the ability of the system to manage the effects of the aging mechanisms of cracking, loss of material, and loss of mechanical closure integrity.

E8.3.2.c Pressurizer Examinations

The pressurizer is a vertical cylindrical vessel, containing removable electric heater elements in its lower section and a water spray nozzle in its upper section. The pressurizer communicates with the reactor coolant at the reactor outlet loop piping through a bottom surge line penetration. Because the surge line is unisolable from the reactor coolant system the pressurizer is provided with over pressure protection by two code safety valves and one electromatic relief valve. Each of these valves is attached to an individual nozzle and line penetrating the upper vessel head of the pressurizer. The electrically heated pressurizer establishes and maintains the reactor coolant system pressure by providing a steam surge chamber and water reserve to accommodate reactor coolant density changes during operation.

Topical Report BAW-2244A "Demonstration of the Management of Aging Affects for the Pressurizer" was reviewed by the NRC in a revised final safety evaluation report dated November 26, 1997. This review identified actions required of a license renewal applicant before BAW-2244A could be accepted in a license renewal application. Except for the timing of the inspection of the heater sleeve-to-sheave partial penetration weld for Oconee Unit 1 and the sheave-to-diaphragm partial penetration weld for Units 2 and 3 (these units do not contain a heater sleeve) these open items were resolved in the NRC draft SER of June 1999.

As a result of the license renewal aging management review and the analysis performed in BAW-2244A pressurizer aging effects were identified that require new or additional inspections. The additional aging effects are:

- cracking of the pressurizer cladding, and items attached to the cladding, aging management of the partial penetration welds that connect the heater sheaths to the diaphragm plates for Units 2 and 3 and the heater sleeve to the heater sheave in Unit 1,

- cracking of small bore nozzles and safe ends, and

- cracking of the internal spray line and spray head .

The applicant proposed the Pressurizer Examinations Program in order to address inspections of the pressurizer not covered by the Alloy 600 Management Program or the Small Bore Piping Inspections. The Pressurizer Examinations program specifically covers the aging management of the pressurizer cladding, internal spray line, spray head, and pressure boundary welds of heater bundle.

The applicant proposed to perform a one-time visual examination of the interior surfaces of the vessel and a liquid penetrant test of the accessible partial penetration weld to evaluate the applicability of these aging mechanisms to Oconee. This examination is intended to determine the need for a more comprehensive and continuing program during the period of extended operation. Because the Pressurizer Examinations Program does not currently exist, the NRC team was unable to judge the adequacy of the program in managing the aging effects identified.

E8.3.2.d Control Rod Drive Mechanism and other Vessel Closure Penetrations Inspection Program

There are 69 4-1/4" OD by 2-3/4" ID Alloy 600 nozzle bodies attached to the interior of the reactor vessel closure head by partial penetration welds. These nozzle bodies are, in turn, joined by a full penetration weld to a stainless steel flanged control rod drive mechanism (CRDM) nozzle adapter. Oconee Unit 3 is equipped with a Type C CRDM and Units 1 and 2 are equipped with a Type A CRDM. The control rod shim safety drive mechanism is attached to the flanged adapter and includes the motor, motor tube, plug and vent valve, actuator, lead screw, rotor assembly, torque extension tube and torque taker, buffer , lead screw guide, and position indicators. A Type C assembly also includes a snubber assembly as part of the lower end of the torque taker assembly.

The Oconee Unit 1 reactor vessel closure head also contains eight 1" (3/4" Sch 160) thermocouple nozzles which are installed by internal partial penetration welds outside the region of the CRDM nozzles. The nozzles are two pieces consisting of a nozzle tube fabricated from Alloy 600 and a mating flange made of Type F 304 stainless steel. Subsequent to the design of the reactor closure head assembly the thermocouples were eliminated and the internal portions of the nozzles were removed by cutting them off 6" below the lower surface of the closure head. Stainless steel blind flanges were installed on the external portion of the nozzle using a bolted configuration.

BAW-2251 “Demonstration of the Management of Aging Affects for the Reactor Vessel”, incorporated in the Oconee application by reference and accepted by the NRC staff in a safety evaluation report issued April 26, 1999, and the Oconee specific aging management review identified primary water stress corrosion cracking as an aging affect for these locations. In addition the applicant has operating experience indicating the presence of craze cracking in the Alloy 600 surfaces of the CRDM nozzles. Inspections of all 69 nozzles were performed during the 1994 refueling outage of Unit 2 at which time twelve indications were found. Eleven of the indications, when investigated further, were below the 2mm calibration threshold. During the 1996 outage two of the nozzles were reexamined using refined techniques. This examination showed the indications had not increased in size. The applicant is planning to perform additional examinations during the 1999 outage to further characterize the indications.

The applicant is actively managing CRDM aging effects at Oconee. The program is comprehensive, the implementing staff are knowledgeable, and the industry information available at Oconee is current. Oconee has information on recent developments at other plants with similar CRDM designs and is using the information to refine the program at Oconee. The team concluded that the content and current implementation of the program is acceptable for managing the aging of the CRDMs and, if expanded to include other penetrations, such as the blanked off thermocouple nozzles, is sufficiently comprehensive to manage them as well.

E8.3.2.e Inservice Inspection Program

Each of the Oconee Units is in the third interval of their ISI program. Unit 1 started this interval on July 15, 1994, and Units 2 and 3, on December 16, 1994. The ISI programs conform to the requirements of ASME Section XI, 1989 Edition, without addenda. The Oconee ISI program uses the alternates offered in seventeen Code Cases. Thirteen of the code cases were endorsed in NRC Regulatory Guide 1.147 with the remaining 4 code cases separately approved by the NRC for use at Oconee. The Oconee license renewal application identifies cracking, loss of material and loss of closure integrity as the applicable aging effects the ISI program is able to manage.

The ISI program, with a few exceptions, cannot by itself detect a loss of material and is generally coupled in the license application with other programs such as the Boric Acid Wastage Surveillance Program for the purpose of detecting corrosion, erosion, and reduction in material by simple wear. The ISI program is basically structured to interrogate welds, and the base material adjacent to welds, for the presence of cracking. Because the program is well suited to the detection of cracking, and a loss of fracture toughness will result in cracking at lower stresses, ISI can be used as an indication of degraded fracture toughness when cracking is detected.  The program is given credit in Table 3.4-1, of the application for specifically managing the reduction in fracture toughness in the Reactor Coolant Pump Casing and Reactor Coolant Pump Cover, when supplemented by the Cast Austenitic Stainless Steel flaw evaluation procedure,  as well as managing the aging conditions identified in the application in paragraph 4.18.1.  It should be noted the applicant uses Code Case N-481, which effectively limits the inspection of the Reactor Coolant Pump Casing and Reactor Coolant Pump Cover to a visual inspection once every ten years.  Although the applicant has committed to ultrasonic test qualifications in accordance with ASME Section XI, Appendix VIII, the appendix currently has no method to qualify the examination of cast stainless components.  Thus, the applicant is in-effect proposing fracture toughness degradation in these components be managed by a visual examination once every 10 years, in accordance with the approved code case.  If a crack were detected, the crack size would be categorized by ultrasonic testing, which is  not supported by a structured qualification under Appendix VIII.  Because the Code requires visual examination that is not sufficient to detect cracking in these components, the NRC staff has proposed the use of an enhanced VT-1 if the components are not screened out by a modified EPRI TR-106092 bounding calculation. The team noted that there is no history of verified cracking in cast stainless components in the industry, thus the examinations proposed by the applicant, as modified by the NRC SER, should be sufficient until Appendix VIII offers a more structured solution to the problem of ultrasonic inspections of cast components.

The applicant states, in paragraph 4.18, that the “inspection intervals are not restricted by the Code to the current term of operation and are valid for any period of extended operation.”  This is not true for the 1989 ASME Edition, the edition the applicant is currently authorized to use, and the most recent edition embraced by the NRC in 50.55a.  For example Examination Category B-D for full penetration welds of nozzles in vessels has a very different inspection sample set for the 2$^{nd}$ and 3$^{rd}$ intervals.  The 1989 edition of the code has no provision for extending the period beyond the fourth interval and does not make any accommodation for the differences in sample sets that may result in extending the 4$^{th}$ interval alone.  Currently no licensee of the NRC can use a more current edition of the code without seeking special dispensation from the NRC.

The 1995 Edition of the code, however, does not limit the samples to 4 intervals, but refers to all intervals beyond the first as subsequent intervals.  The 1996 Addenda expands the idea of extending intervals in IWB-2420 by stating that “the sequence of component examinations which was established during the first inspection interval shall be repeated during each successive inspection interval, to the extent practical.”  This addenda therefore allows for a 5$^{th}$ and 6$^{th}$ interval that are the same as the preceding 2$^{nd}$ through 4$^{th}$ intervals.  These later editions of the ASME code, when reviewed and approved by the NRC, would be appropriate for an extended period of operation because they allow for the last interval to be repeated endlessly. The inspectors pointed out to the applicant that this matter needs to be resolved in the future with the NRC.

Based on its review and discussion with applicant personnel, the team concluded that the Oconee “Third Ten-Year Interval Inservice Inspection Plan”  Revision 4, Addenda ONS-024, complies with the requirements of ASME Section XI, 1989 Edition and is sufficiently robust to manage the aging affects listed in the application as modified by the NRC.

E8.3.2.f Boric Acid Wastage Surveillance Program

The Boric Acid Wastage Surveillance Program, primarily controlled by procedure OP/0/A/1102/028, Revision 002 “Reactor Building Tour”, is given credit, in the license renewal application for managing the loss of material due to boric acid corrosion of carbon steel and low alloy steel. The Boric Acid Wastage Surveillance Program is primarily a issued inspection of the systems and components the reactor building to detect leakage. The inspection is conducted after first entering the reactor building following periods of reactor operation and before final reactor building closure. Leakage is evidenced by moisture or the presence of boric acid powder or crystals on the exterior of valves, connections, and insulated surfaces. Any evidence of leakage is noted on a summary sheet and referred to the program manager for review and disposition. If the program manager subsequently verifies the presence of leakage, the system manager is informed and a work request is issued. If the leak is repaired before the end of the outage the work order is closed. If the leak cannot be repaired and/or an evaluation is made to accept the leak as-is, the condition is entered into the plant investigation program.

Although the procedure does not included a check list to assure that each system is inspected and that key components are not missed, the procedure generally refers to systems and valves that need to be examined. For example , in Mode 3, the inspection of the reactor building 3$^{rd}$ floor consists of two instructions: “2.3.1 Inspect RxV Head for leaks (RCS, Component Cooling)” and “ 2.3.2 Verify missile shield blocks installed.” The directions for the 4$^{th}$ floor are slightly more prescriptive because they include the ‘A’ and ‘B’ MS line vents, RC-3 spray control outlet block, RC-4 Pressurizer Relief Block, Pressurizer heater bundles, $T_{hot}$ RTD in the ‘A’ and ‘B’ cavity, A1 and B1 RCP Bowl, A2 and B2 RCP Bowl, and the $T_{colc}$ RTD in the ‘A’ and ‘B’ cavity.

The NRC inspection team concluded that the plant procedures could be improved with more specific instructions, but the Boric Acid Wastage Surveillance Program will manage the aging effect of boric acid corrosion of susceptible materials.

E8.3.2.g Program to Inspect the High Pressure Injection Connections to the Reactor Coolant System

This was an existing program that was identified for managing cracking of the nozzles, thermal sleeves, and associated piping and piping welds in the HPI portions of the Reactor Coolant branch lines. This program is described in Section 4.22 of the LRA, which indicates that it involves radiographic, dye-penetrant, and ultrasonic examinations of the effected components. The ultrasonic and dye-penetrant examinations are used to identify cracks in the nozzles, piping, and piping welds. The radiographic examinations are used to identify gaps growing at the thermal sleeve/piping connection interface, indicating loosening of the thermal sleeves. The inspectors reviewed the description of this inspection program provided in the LRA and discussed the program with responsible applicant personnel. In addition, the inspectors reviewed further details of the attributes of the program described in Specification OSS-0274.00-00-0004. The inspectors verified implementation of the program through:

- Review of Section 7 of the Inservice Inspection Plan
- Review of the piping and piping weld ultrasonic examination procedures
- Review of the thermal sleeve radiographic procedures

- Review of records for ultrasonic examinations G02.001.007B (3/28/98); G02.001.005C (4/12/98), and G02.001.007B (3/28/98)
- Review of the radiographic film of the 1998 thermal sleeve examinations

The inspectors found that this program was implemented consistent with the LRA and the NRC SER, dated June 1999.

E8.3.2.h Chemistry Control Program

This was an existing program that was identified for managing corrosion in systems containing primary, secondary, and component cooling water; and corrosion in the Standby Shutdown Facility Fuel Oil System. The program is described in Section 4.6 of the LRA, which indicates it involves sampling and analysis of the fluids, limiting the levels of certain impurities, and use of chemical additives to preclude corrosive environments.

The inspectors reviewed the description of this inspection program provided in the LRA, and discussed the program with responsible applicant personnel. The inspectors verified implementation of the program through a review of the following:

- Chemistry Manual 3.10, which specifies primary and component cooling water sampling frequencies, parameters sampled, limits, and corrective actions

- Chemistry Manual 3.8, which specifies secondary water and SSF fuel oil sampling frequencies, parameters sampled, limits, and corrective actions

- Oconee Nuclear Station, January - May 1999 Primary Chemistry Data Review Meeting, issued as Memorandum to File dated July 6, 1999 (File: OS-709.00)

- Oconee Nuclear Station, January - May 1999 Secondary Chemistry Data Review, issued as Memorandum to File dated July 6, 1999 (File: OS-709.00)

- Trended chemistry levels recorded in the applicant's electronic database from January to June 1999 for all three Oconee units, including: Component Cooling water chromate and phosphate; Reactor Coolant chloride, fluoride, oxygen, and sulfate; Spent Fuel Pool water chloride; Hotwell oxygen; and final Feedwater oxygen, chloride, and sulfate

- Trended carbohydrazide levels recorded in the applicant's electronic database from May 23 to June 19, 1999, for the wet layup of both Unit 1 Steam Generators

The inspectors found that the Chemistry Control Program was implemented consistent with the LRA and the NRC SER dated June 1999. The inspectors noted that the program did not require monitoring of some chemical parameters at all sampling locations, as discussed in Section E.8.2.4 of this report.

E.8.3.2.i Galvanic Susceptibility Inspection

This was a new, one-time, program for assessing the impact of galvanic corrosion as an aging effect in Oconee raw water systems. It was described in Section 4.3.3 of the LRA, which indicated that it will involve volumetric examinations at selected carbon steel to stainless steel junctions. The examination results will be used to determine whether additional programmatic oversight will be required to manage galvanic corrosion as an aging effect.

The inspectors reviewed the description of this inspection program provided in the LRA and discussed the program with responsible applicant personnel. In addition, they reviewed further details of the attributes of the inspection described in Section 4.1.7.4.2 of Specification OSS-0274.00-00-0005. However, procedures have not been developed for this inspection. The LRA indicated that the inspection would be completed following issuance of the license extension, and prior to February 6, 2013. The plans for the inspection discussed by licensee personnel and described in Specification OSS-0274.00-00-0005, were consistent with those stated in the LRA and the NRC SER.

E8.3.2.j Cast Iron Selective Leaching Inspection

The Cast Iron Selective Leaching Inspection is a new, one-time, program that the applicant intends to implement for assessing the impact of selective leaching of cast iron as an aging effect in Oconee raw water, treated water, and underground environments. The planned inspection is described in Section 4.3.2 of the LRA, which indicates it will involve Brinnell Hardness checks on cast iron pump casings from several systems. The checks will be used to determine whether loss of material due to selective leaching will be a concern during the period of extended operation.

The inspectors reviewed the description of this inspection program provided in the LRA and discussed the program with responsible applicant personnel. In addition, the inspectors reviewed further details of the attributes of the inspection described in Section 4.1.6.4.2 of Specification OSS-0274.00-00-0005, however, procedures have not been developed for this inspection. The LRA indicated that the inspection would be completed following issuance of the license extension, and prior to February 6, 2013. The plans for the inspection described by licensee personnel and in Specification OSS-0274.00-00-0005 were consistent with those stated in the LRA and the NRC SER.

E8.3.2.k Small Bore Piping Inspection

This inspection is a new, one-time, program for the small-bore Reactor Coolant System piping that does not receive a volumetric examination during Inservice Inspection. This program will be used to confirm that service-induced weld cracking is not occurring in the small-bore Reactor Coolant System piping. The planned inspection is described in Section 4.3.12 of the LRA, which indicates it will involve either a destructive or a non-destructive examination of the inside surface of the piping at selected locations. The team reviewed the description of this program provided in the LRA and discussed the program with responsible applicant personnel. The inspectors found that the applicant plans to replace the Oconee Steam Generators and that small-bore pipe samples obtained during the replacement were to be used for the examinations. The inspection procedures have not been developed, however, the LRA indicated that the inspection would be completed following issuance of the license extension, and prior to February 6, 2013. The plans for the inspection described by licensee personnel were consistent with those stated in the LRA and the NRC SER.

E8.3.2.l The Reactor Building Spray System Inspection Program

The Reactor Building Spray System Inspection is a planned, one-time, new inspection to address the aging effects of cracking in stainless steel components exposed to a treated water environment. The planned inspection is described in Section 4.3.9 of the LRA and involves volumetric examination of a length of pipe chosen from susceptible piping locations between valves BS-1 and BS-2, and normally open drain valves BS-15 and BS-20. The inspection will be used to determine whether loss of material due to pitting corrosion and cracking due to stress corrosion have occurred and whether further programmatic aging management will be required to manage these effects.

The inspectors reviewed the description of the planned inspection as defined in the LRA and discussed the planned program with responsible applicant personnel. Although the inspection procedure has not been developed, the applicant stated in its LRA that the inspection will be implemented after issuance of the renewed operating license, and prior to February 6, 2013. The plans for the Reactor Building Spray System Inspection were found to be consistent with the LRA and the Oconee License Renewal SER.

E8.3.2.m Treated Water Systems Stainless Steel Inspection

The Treated Water Systems Stainless Steel Inspection is a planned, one-time, new inspection to address the aging effects of loss of material due to pitting corrosion and cracking due to stress corrosion of stainless steel components exposed to treated water. The planned inspection is described in Section 4.3.13 of the LRA. Three groups of components are involved; 1) those exposed to filtered water developed by the Oconee water treatment process, 2) those exposed to demineralized water developed by an additional step in the Oconee water treatment process, and 3) those exposed to potable water from the city of Seneca, South Carolina. The planned inspection involves volumetric examination of samples of piping, including a weld and heat affected zone, and internal inspection of valves in each of the three groups. The inspection will be used to determine whether loss of material due to pitting corrosion and cracking due to stress corrosion have occurred and whether further programmatic aging management will be required to manage these effects.

The inspectors reviewed the description of the planned inspection as defined in the LRA and discussed the planned program with responsible applicant personnel. Although the inspection procedure has not been developed, the applicant stated in its LRA that inspection will be implemented after issuance of the renewed operating license, and prior to February 6, 2013. The plans for the Treated Water Systems Stainless Steel Inspection were found to be consistent with the LRA and the Oconee License Renewal SER.

E8.3.2.n Service Water Piping Corrosion (Inspection) Program

As noted in section E8.2.3 above, the Service Water Piping Corrosion Program is an existing program for managing the effect of loss of material due to general corrosion and microbiological corrosion in components exposed to a raw water environment. As discussed in Section 4.25 of the LRA, the program will be enhanced to add inspection locations for the Keowee Service Water System. The inspectors reviewed Revision 1, dated November 1, 1995, to the program and discussed the program with responsible applicant personnel. The program consisted of ultrasonic testing measurements of wall thickness of over 30 piping components in the three Oconee Units. During the review, the inspectors noted the following:

- The program was an informal program, i.e., it had not been documented and formally approved as a site procedure or program.;

- If wall thinning is identified at an inspection location, the informal program provides only for disposition of inspection results at that location and does not address generic actions, i.e., evaluations or sample expansion for the affected system or other systems ; and
- The program provides little detail on required inspection intervals. Review of inspection data revealed that Unit 1 components were inspected in 1990 and again in 1995. Units 2 and 3 components were inspected in 1991. The responsible engineer stated that Units 2 and 3 components will be inspected a second time in the next few years.

Although the above program concerns were identified, available inspection data indicated that the raw water piping has experienced minimal deterioration from internal corrosion. The inspectors concluded that the Service Water Piping Corrosion Program, when enhanced by adding inspection locations for Keowee components, will be consistent with the LRA and the NRC SER.

E8.3.2.o Service Water System Performance Testing Activities

As noted in section E8.2.3, the LRA refers to System Performance Testing Activities for managing the effects of fouling for the LPSW System. This testing involves periodic flow testing of various piping and components in the system. In addition to the review of specific completed Performance Test Procedures and data as detailed above, the inspectors reviewed Nuclear Station Directive (NSD) 408.8 and Site Directive 4.1.1, which govern the performance of all periodic testing at the site. The inspectors team concluded that Performance Testing Activities had been implemented and procedures covered the activities referred to in the LRA for the LPSW System. The inspectors concluded that the Performance Testing Activities for the Low Pressure Service Water System were consistent with the LRA and the SER.

<u>E8.3.2.p Preventive Maintenance Programs for Aging Management</u>

The applicant credited ten preventive maintenance (PM) activities in managing the effects of aging, as discussed in the LRA, Subsection 4.3.8, and as evaluated in the NRC SER, Subsection 3.2.10. The inspectors reviewed the overall application of PM as a means of aging management and specific applications, including the aging management of Auxiliary Service Water (ASW) piping fouling, Borated Water Storage Tank (BWST) internal coating degradation, Component Cooler tube degradation, and Condenser Circulating Water (CCW) internal piping coating degradation.

E.8.3.p.1 Quality Assurance Relationship to Preventive Maintenance

E.8.3.2.p1 In reviewing the PM program, the inspectors noted that the NRC SER stated that the PM program is controlled by the NRC required quality assurance plan pursuant to 10 CFR Part 50 , Appendix B, and that the quality assurance plan covers all structures and components subject to aging management review. Through discussions with the applicant, the inspectors were told that the PM Program is not controlled under the applicant's Appendix B Program, with the exception of the BWST and Decay Heat Coolers (QA-1 components). The applicant stated that if problems are discovered as a result of performing PMs, the Problem Investigation Process (PIP) would still be used to implement corrective action. The initial step in the PIP is to categorize each event as “more significant events” (MSE) or “less significant events”(LSE). The criteria for determining MSE/LSE appear to be complex and subjective, and independent of safety-related/nonsafety-related characterizations or the need to implement corrective actions under Appendix B. In addition, applicant procedure NSD-208 states that any event may be reclassified to a lower category per management discretion even though it meets the specified criteria if a root cause or apparent cause is not needed.

The inspectors reviewed application materials and meeting minutes and found records indicating that the applicant's PM activities do not fall under the oversight of the applicant's quality assurance program. However, if the PMs uncover a problem, the problem would be placed in the applicant's problem investigation process. Specifically, Duke stated that responses to RAIs 4.3.9-3, 4.3.9-4, G-8 and 4.3.13-3 discuss the PIP and the quality assurance corrective action process. The SER statements relating to the PM activities being implemented in accordance with Appendix B need to be reevaluated and revised accordingly.

E8.3.2.p.2 Coating Inspection PMs

The Oconee Nuclear Station (ONS) Coating Program is used to manage all structure and component coating activities on site. The program is divided into two separate programs for safety-related (as documented in the Nuclear Coatings Maintenance Manual) and nonsafety-related (as documented in the Field Coatings Maintenance Manual) structures and components. All coating activities relating to safety-related structures and components are implemented under the site QA programs, 10 CFR Part 50, Appendix B and nonsafety-related structures and components are not.

The program activities are well documented in a variety of documents. The PM program is used to initiate the aging management inspection activities for the interior coating of the Borated Water Storage Tank (BWST), and the Condenser Circulating Water (CCW) intake and discharge piping. Each of these components was coated during initial installation and have been maintained through the life of the plant. The formal coating program was implemented in about 1981 for the CCW piping, and 1991 for the BWST. The CCW piping has been inspected once every five years since initial installation. A PM activity to inspect the interior coating of the BWST once every five years was initiated in approximately 1991. Although these inspection activities have been in place for some time, limited documentation is available for many of the earlier inspections.

The inspection activities are automatically initiated under the PM programs and the results are currently being documented. The results for the last CCW and BWST inspections were documented in OSC-7380, an ONS calculation entitled “CCW Intake and Discharge Piping 5 year Civil Coating Inspection,” and as part of the “Task Completion Comments” in the PM computerized system, respectively. The team verified that the content and implementation of this program were consisted with the LRA and NRC SER. In addition, the team determined that the program documentation is currently being maintained in an auditable and retrievable form sufficient to provide the necessary demonstration that the effects of aging are being maintained consistent with the CLB.

E8.3.2.p.3 Eddy Current Testing

Tubes for the Component Coolers, Condensate Coolers, Decay Heat Coolers (Low Pressure Injection heat exchangers), Main Condenser, and Reactor Building Coolers are all cleaned and inspected for wall thinning by Eddy Current Testing (ECT) under the PM Program once every two years. The PM process automatically generates a work order to initiate cleaning and ECT activities for each of the coolers and the main condenser.

This work is performed by Duke Engineering Services, a subsidiary wholly owned by the applicant. There are no site procedures for ECT, however, the applicant indicated that Duke Engineering Services has the necessary procedures to perform this work. The results of the ECT are documented in an auditable and retrievable form in individual reports for each cooler. The results are reviewed by the system engineer responsible for that equipment. The system engineer stated that they generally use the industry standard of a 60% through-wall indication as the criterion for plugging a tube. However, the only ONS requirement to ensure plugging at 60% through-wall is a internal letter and a calculation for plugging of the Decay Heat Coolers. The applicant indicated that it usually uses the 60% through-wall criteria as guidance for plugging tubes in the remaining coolers and the main condenser. The system engineer informal practice/procedural requirement with the DES staff performing the ECT, and may choose not to plug a tube until there is indication of up as much as 85% through-wall degradation.

Based on discussions with the applicant engineer, the inspectors learned that in 1996 and 1998 ECT for the Component Coolers was canceled. Because ECT is performed once every two years, the Component Cooler ECT PM, which is normally done every two years will be delayed at least six years. The applicant indicated that when the renewed license is issued, all aging management activities will be identified as licensing commitments, which can not be voided or eliminated without the proper engineering evaluations.

E8.3.2.p.4 Auxiliary Service Water System Inspection

Aging management of the Auxiliary Service Water (ASW) System is performed by a PM that requires a visual inspection of the piping down stream of the pump discharge check valve. In Specification OSS-0274.00-00-005, the applicant states that this location is downstream of the recirculation line and therefore is stagnant. This location is expected to be indicative of the entire section of piping and associated components that is downstream of the recirculation line and upstream of the piping containing condensate grade water. The inspection is to used to examine the general condition of the piping, although fouling is the primary focus. In the LRA, the applicant states that aging management of the ASW system due to loss of material will also be managed by visual PM inspection.

In the LRA, Table 4.3-1, Preventive Maintenance Activities, the applicant also states the purpose of ASW piping inspection activity (PM) is to identify fouling due to Micro-organisms, and silt. In addition, in its response to the staff's request for additional information, RAI 4.3.8, the applicant restated that the purpose of the PM is to perform a visual inspection in the vicinity of the discharge check valve (as a lead indication of the entire section of pipe) for the purpose of detecting loss of material.

In the SER, Subsection 3.2.10.2, the staff assessed the loss of material of the ASW piping under the PMs evaluation. The SER states that the loss of material is managed by the PM activity that initiates a visual inspection of the piping downstream of the pump discharge check valve and accepted this location to determine the general condition for the portions of ASW system piping in question.

During this inspection, the inspectors were informed that the PM was limited to a visual inspection for fouling only, and that this PM was not used to manage the loss of material. Photographs of the piping taken during the last inspection performed under this PM showed indications of corrosion and possible pitting. In response to questions from the team, the applicant indicated that no measurements or ultrasonic testing, and trending of wall thickness was performed under this PM. However, the applicant stated that ultrasonic testing under the ONS Service Water Piping Inspection Program which is assessed in Section 3.2.13 of the NRC SER. was used to monitor loss of material. Ultrasonic testing for the ASW piping is performed at the discharge of CCW-101 and not in the piping with the stagnant flow condition at the pump discharge check valve. Because the aging management program implemented at Oconee differs from the program described in the licensing material submitted by the applicant, the relevant information in the SER should be reevaluated and revised, as appropriate.

E8.3.2.q Piping Erosion/Corrosion Program

As noted in Section E8.2.4 and E8.2.5, , one of the aging management programs for the effect of loss of wall thickness in the Feedwater (FW) System and portions of the Emergency Feedwater (EFW) System is the Piping Erosion/Corrosion (E/C) Program. The inspectors reviewed the E/C program as documented in Engineering Support Program "Piping Erosion/Corrosion Program", Revision 1, dated August 5, 1998. The program included the portion of the FW and EFW Systems included in the scope of License Renewal. In addition to review of the Program document, the inspectors reviewed the E/C Program Test Results Manual for Units 1, 2, and 3. Additionally, the following specific test data were reviewed:

- Summary of historical wall thickness measurements for FW and EFW Systems for Units 1, 2, and 3
- EPRI CHECKWORKS "PASS 1" and "PASS 2" Wear Rate Analysis Combined Summary Reports for FW System for Units 1,2 and 3
- Data Evaluation Work Sheets, including ultrasonic (UT) thickness measurement data for the recent Unit 1 refueling outage (EOC-18) for the FW and EFW Systems

Review of the data indicated that no significant E/C is occurring in the FW and EFW systems. The inspectors concluded that the E/C program has been implemented consistent with the LRA and the NRC SER.

E8.3.2r Keowee Oil Sampling Program

As noted in Section E8.2.9 of this report, the Keowee Oil Sampling program was a new program identified for managing the effect of loss of material in Keowee scoped components exposed to an oil environment. Although the Keowee Oil Sampling Program is an existing program, the applicant treated the program like a new program since it had been in effect as an informal program performed by Keowee Hydro personnel and was in the process being formalized into plant procedures. Maintenance Procedure MP/0/A/2000/075, which described the requirements for sampling oil from various equipment at the Keowee Hydro plant, was issued on February 17, 1998, as the first step to formalize the oil sampling program into plant procedures. The inspectors reviewed the last 3 completed records for MP/0/A/2000/075, which documented taking oil samples in April 1998, October 1998 and April 1999. The inspectors also attempted to review the results from these three samples. However, only the results from the sample taken April 1998 could be located. Although the MP was signed off as being completed in October 1998 and April 1999, the applicant could not locate oil analysis results from these samples and could not determine what happened to the samples. In addition to review of the oil analysis results for April 1998, the inspectors reviewed a summary of the oil analysis results from 1990 through 1996. Although the results indicated that the oil quality had always been maintained, the frequency of sampling had been inconsistent. For example, no data was available for 1991 and 1993 and in some years, the oil was only sampled once instead of every 6 months. The inspectors concluded that, although the Keowee Oil Sampling Program was in place and had been implemented for the Governor Oil System, improvements in implementation were needed. The inspectors found that MP/0/A/2000/075 only covered the method and locations to sample. No details were provided as to frequency of sampling, the logistics of how oil samples get analyzed, what parameters to analyze for, acceptance criteria, etc. The applicant stated that they were aware of the deficiencies in the program and thus identified it as a new program to be formalized and improved for license renewal purposes.

E8.3.2.s Keowee Fire Protection Program

For the portion of the Keowee Service Water System in the scope of license renewal, the LRA refers to the Fire Protection Program for managing the effects of fouling for components exposed to raw water and loss of material for components exposed to an air environment. The fire protection activities taken credit for in the LRA were periodic surveillances of the fire protection portion of the Keowee Service water system. In addition to review of the completed Performance Tests (surveillances) detailed in Section E8.2.8, the inspectors reviewed the Engineering Support Program Basis Document Fire Protection Program, Revision 0. The Fire Protection Program and surveillances for the Keowee Fire Protection equipment had been implemented and covered the activities referred to in the LRA for the Keowee Service System. The team determined that the Fire Protection Program for the Keowee Service Water System was consistent with the LRA and the NRC SER.

E8.3.2.t Keowee Air and Gas Systems Inspection

The Keowee Air and Gas Systems Inspection is a new, one-time, program that the applicant intends to implement for assessing the general corrosion of carbon steel components exposed to air or gas in the Keowee Carbon Dioxide, Depressing Air, and Governor Air Systems. The planned inspection is described in Section 4.3.3 of the LRA, which indicates it will involve volumetric and visual examinations at specified locations. The examination results will be used to determine whether additional programmatic oversight will be required to manage general corrosion in these systems as an aging effect.

The inspectors reviewed the description of this inspection program provided in the LRA and discussed the program with responsible applicant personnel.  In addition, they reviewed further details of the attributes of the inspections described in Sections 4.1.47 and 4.1.48 of Specification OSS-0274.00-00-0005.  Selected portions of carbon steel components in each system are to be inspected for loss of material due to general corrosion.  The inspection results will be used to assess the likelihood of the impact of general corrosion on component functions.  The LRA indicated that the inspection would be completed following issuance of the license extension, and prior to February 6, 2013.  The plans for the inspection described by applicant personnel and Specification OSS-0274.00-00-0005 were consistent with those stated in the LRA and the NRC SER.

The inspectors found that an inspection of the Keowee Unit 2 tanks and pipe had been completed on September 16, 1998.  They reviewed the inspection procedure and results documented in Work Order 98084472.  The inspection implemented by the procedure was consistent with that stated in the LRA, Specification, and the NRC SER, except that the pipe was not inspected volumetrically.  Applicant personnel stated that the inspection had not been accepted as meeting the program requirements and that inspections meeting the criteria would be completed by the February 6, 2013, date given in the LRA.  The inspection found there was little or no rust and that the interiors of the tanks were in excellent condition.

8.3.2.u Keowee Turbine Generator Cooling Water System Performance Testing Activities

This is an existing program that the LRA identified for managing fouling in the Keowee Turbine Generator Cooling Water System.  The inspectors reviewed the description of this program provided in the LRA and discussed the program with responsible applicant personnel.  In addition, they reviewed further details of the attributes of the program described in Section 4.1.50.4.3 of Specification OSS-0274.00-00-0005.  As described in the LRA, this performance testing is simply normal operation of Keowee to supply power to the grid.  This results in more severe loads on the cooling system than experienced in supplying power for an Oconee accident condition.  The performance testing activities were adequately implemented, as Keowee is routinely operated to supply power to the grid.  According to the applicant’s July 13, 1999, Intrasite Letter, Keowee Units 1 and 2 have run fully loaded to the grid 6.4% and 3.8% of the time during 1999.  The inspectors found that the Keowee performance testing described by applicant personnel and Specification OSS-0274.00-00-0005 was consistent with that stated in the LRA and the NRC SER.

E8.3.2.v Keowee Turbine Generator Cooling Water System Preventive Maintenance Program

The LRA indicated that Preventive Maintenance Activities would be used to manage general and localized aging in this system.  It did not describe this program but, instead, indicated that a one-time activity assessment would be performed which would assess the effectiveness of the program.  Subsequently, the applicant’s response to NRC RAI 4.3.8-1 provided a description of the attributes of the Keowee Turbine Generator Cooling Water System Preventive Maintenance Program; and, in a response to NRC RAI 4.3.8-8, the applicant withdrew the proposed one-time activity assessment.

The inspectors reviewed the description of this preventive maintenance program provided in the RAI 4.3.8-1 response and discussed the program with responsible applicant personnel. In addition, they reviewed further details of the attributes of the preventive maintenance described in Section 4.1.50.4.4 of Specification OSS-0274.00-00-0005. The program consists of cleaning the strainers in the system and inspecting them for deterioration at specified intervals.

The inspectors verified the applicant's implementation of these activities through a review of the following completed weekly and bi-monthly preventive maintenance work orders for the two Keowee units: 98172753 (Unit 1, weekly), 98172754 (Unit 2, weekly), 98158947 (Unit 1, bi-monthly), and 98158946 (Unit 2, bi-monthly). The program implemented in work orders (and associated procedures) reviewed by the inspectors was consistent with that described in the applicant's RAI response, Specification OSS-0274.00-00-0005, and the NRC SER dated June 1999.

E8.3.2.w 230 Kilovolt (kV) Keowee Transmission Line Inspection

The team reviewed the ONS 230 kV Keowee Transmission Line Inspection as described in section 4.29 of the Application for Renewed Operating License (LRA). This program was an existing program used to monitor the condition of the overhead 230 kV Keowee transmission line structures between the Keowee Hydroelectric Station and the ONS switchyard. The inspection is performed by Duke Power Delivery personnel and coordinated by ONS personnel. The inspection consisted of a visual examination while climbing the towers and has been performed on 5 year intervals. Operating experience to date have identified some instances of loose bolts and slight rust where galvanizing was burnt off due to lightning strikes. Wear and aging of the structures was not identified.

The team discussed the inspection history with ONS personnel and performed a visual inspection of the portions of the towers visible from the ground and found no evidence of wear or aging. The team determined that the inspection frequency for the implementation of this program has changed from the frequency described in section 4.29 of the LRA. The LRA indicated a visual inspection every 5 years while the current plans for the inspections by Duke Power Delivery personnel are to perform a visual inspection while climbing the tower every 7 years with an annual visual inspection by helicopter flyover. The annual helicopter flyover inspections were utilized for the rest of the Duke Transmission System. The team concluded that the proposed change to the inspection would satisfactorily manage the aging of the Keowee to Oconee transmission towers, but that the applicant would have to revise the appropriate license renewal documents to reflect the program inspection type and frequency change.

c. <u>Conclusions</u>

The team concluded that the existing aging management programs for civil structures were conducted in a manner as described in the License Renewal Application. However, in the past these inspections have not always been completed in the specified time frame.

The team concluded that the existing mechanical aging management programs were being conducted as described in the applicant's License Renewal Application. However, the inspection revealed that the existing informal programs have minimal procedural guidance and were not always conducted at the specified frequency.

The team determined that some aging management programs described in the applicant's LRA have not been developed. The team expressed concern that there was no management program or tracking mechanism in place to inservice the development and implementation of these programs. In addition, there were instances where the scope or content of existing programs were had been changed from that described in the License Renewal Application.

E8.4 Electrical Component Aging Management

a. Inspection Scope (71002)

The applicant described its aging management review of electrical components at ONS for license renewal in Section 3.6, "Aging Effects for Electrical Components" of Exhibit A of the License Renewal Application (LRA). In its onsite inspection, the team examined the ONS material condition, analyses, and supporting documentation to verify the LRA conclusions for Phase Bus, Switchyard Bus, Insulated Cables and Connections, Insulators, and Transmission Conductors "that the identified aging effects for these electrical components are not applicable and no aging management programs at ONS are necessary for these electrical components".

b. Observations and Findings

In the LRA the applicant discussed possible aging effects and concluded that the identified aging effects for Phase Bus, Switchyard Bus, Insulated Cables and Connections, Insulators, and Transmission Conductors are not applicable and no aging management programs are required. The inspection team performed visual inspections of these electrical components and reviewed ONS operating experience to attempt to verify the applicant's conclusion in the LRA. For Phase Bus, Switchyard Bus, Insulators and Transmission Conductors, the inspection did not identify the existence of any of the applicable aging effects and, the conclusion in the ONS LRA and NRC SER " that no aging management programs are required for these electrical components" is valid. However, for electrical cables and connections, the inspection team concluded that the potential aging effects of moisture, radiation, and heat identified in the LRA are applicable at ONS. Based on the evidence of aging effects and the team's review of actual plant experience, the team could not agree with the applicant that no aging management review is needed for electrical cables and connectors for the period of extended operation. The areas of focus and the inspection team's findings for electrical cables and connections that support this conclusion are discussed below:

Observations within Unit 1 Reactor Building

During a June 22, 1999, visual inspection (walkdown) of the Unit 1 Reactor Building, the inspectors identified a number of concerns regarding electrical cable and connections:

- Cables in the area above and adjacent to the reactor core that supply power to the fuel handling bridges were badly damaged from exposure to elevated temperature, possibly radiation, and mechanical stress to the cables as a result of movement of the two refueling bridges.

- A cable tray on the Unit 1 East Side second level showed severe signs of thermal degradation to most of the cables in the tray. The cables appeared to have been damaged from heat generated from a 16" feedwater line located directly beneath the cable tray. ONS personnel stated that this condition exists at the same location in all three operating units with Unit 3 cables exhibiting the most degradation. ONS personnel indicated that they had no reason to question whether the cables were still functional.

- Rust was noted on a number of cables with flex-conduits and braided metal jackets. The applicant explained that the rust resulted from contact with boric acid solution dripped or sprayed on them during plant operation or outages. The metal jacket prevents visual observation of the insulation so the potential effects from boric acid on the cable insulation could not be observed. The applicant was requested to evaluate the potential effect of boric acid on cable insulation.

- Numerous electrical cables have been designated as abandoned, with cut off ends hanging out of cable trays not tagged or marked “deleted” after being abandoned.

Observations within Unit 1 Auxiliary and Turbine buildings

During June 23, and July 28, 1999, walkdowns of the Unit 1 Auxiliary Building and Turbine Building, the following observations were made:

- Similar to the Reactor building, numerous electrical cables have been designated as abandoned without clear marking.

- Electrical panels containing cables, connectors, and terminal blocks were inspected for any ongoing aging degradation and none was observed. ONS personnel stated that there were early construction problems with terminal blocks but they have been corrected.

- One situation was noted in the lower level of the turbine building where a conduit was noted to be routed beneath the piping insulation creating a hot spot.

- The applicant earlier identified a potential problem with floor wax and wax strippers getting on cables potentially resulting in cable aging due to contact with chemical stressors.

- The sump pump located in the CT-5 cable trench in the turbine building has not operated properly for many years. A portable sump pump had been installed, but was ineffective in removing the water. Currently, water is removed by a rubber hose to the Unit 3 Turbine Building sump via siphon action. The cables in the trench were coated with mud and silt indicating that they have been frequently submerged.

Additional walkdowns were performed of the SSF, yard area, and intake area cable trenches and selected manholes. One manhole at the intake area was noted to have standing water in it.

Review of past operating experience for cables and connections

At the request of the inspection team, the applicant searched their Problem Investigation Process (PIP) database on the keyword “cables” and identified approximately 500 PIPs on cables and connections from the period 12/93 thru 6/99. The inspection team reviewed summaries of the 500 PIPs and selected 63 PIPs on cables and connections for further review that appeared to be potentially related to cable aging.  Attachment 1 to this report lists the PIPs reviewed sorted by the inspectors' observation of the type of problem documented.  The inspectors observed that 55% of the PIPs were potential aging issues related to connectors, high temperature effects, moisture/boric acid, and Keowee underground cable.  The remaining 45% of the PIPs were related to improper installation or "other" causes.  The inspectors also reviewed selected "work orders" documenting corrective actions that have been taken for various problems.  The documents described local conditions in the plant that over time could produce the aging effects of heat, radiation, and moisture with boric acid exposure that were identified in the LRA.  Areas of particular concern are thermal aging in the steam generator cavity and pressurizer areas of the Reactor Building; boric acid contact with Kapton insulated pressurizer heater cables and nylon terminal blocks; standing water or submergence in cable trenches; and potential degradation of the 13.8kV underground feeder cable from Keowee to the plant (1 mile) based on recent partial discharge test results.

Following the June 22,1999, walkdown in the Unit 1 Reactor Building, the applicant was requested to evaluate the potential effect of boric acid solution on cable insulation.  The inspectors were shown a letter dated 7/22/99, from an industry cable consultant to an applicant engineer stating the applicants conclusion that with the exception of Kapton insulation and Nylon (connectors and terminal blocks) boric acid solution will not have a negative effect on the cable insulation materials used at ONS.  The inspectors agreed with the applicant's conclusion with the exception of potential boric acid ingress into cable connector pins which can result in connector failure due to shorting.

The inspectors discussed cable experience with the ONS cable system engineer and applicant personnel and determined that there have been instances where moisture aging stressors have affected cables at Oconee.  Additionally the team learned that ONS performs cable megger checks of pressurizer heater cables at each refueling outage and that there have been repeated problems with the cable to heater connectors.   PIPs reported moisture and boric acid noted near the pressurizer and this can have an aging affect on Kapton insulation which is used in the pressurizer heater cables.

There was a failure of a 4 kV cable to the B High Pressure Service Water Pump which occurred in 1980 where the cable had minor jacket damage and there was water in the buried conduit containing the cable.  Moisture was stated as the most likely cause of the failure combined with the jacket damage.

Following the July 15, 1999, walkdown of the Turbine Building in which the inspectors observed that some cables in the cable trench are subjected to standing water or submergence on occasion, the applicant provided a letter dated July 26,1999, from an industry cable consultant to an applicant engineer which concluded that the types of materials typically used for cable jackets and insulation at Oconee can be subjected to submergence without a deterioration of the materials.  While industry submergence tests typically last for 14 days, the inspectors noted that the effects of long-term submergence on the insulation resistance is unknown.  Currently, the applicant does not periodically measure insulation resistance values for cables in trenches that have been subjected to standing water or submergence.  Therefore any insulation degradation that may be occurring on cables that have been repeatedly submerged is unknown.

The inspectors reviewed the results of an electrical system visual inspection conducted by Duke personnel in support of license renewal. A series of electrical walkdowns were performed in February, March, August, and November, 1996, to look at the general condition of electrical equipment within the scope of license renewal to determine if any applicable aging effects are occurring. The potentially adverse conditions observed as a result of the walkdowns were documented in a series of PIPs. Examples of the deficient conditions identified during the walkdowns were as follows:

- Cable support, separation, and bend radius issues.
- Damaged cable jacket, conduit, or missing hardware.
- Potential thermal hot spot.
- Evidence of corrosion damage to cable, boxes, or components.
- Potential chemical interaction.

After reviewing this information, the inspectors observed that the applicant's inspections were comprehensive and could have formed the baseline inspection of an aging management program of periodic monitoring of cable and connector conditions. It was noted that the applicant did not provide any information on cables and connections in the LRA under "Oconee operating experience" from the 1996 electrical walkdowns. Some of the conditions identified during the walkdowns were corrected and some remained open.

During the inspection the team learned that the applicant has performed several partial discharge tests on the Oconee/Keowee buried underground cables to attempt to detect any cable insulation degradation. The inspectors discussed the test methods and results with the applicant engineers. The partial discharge test is a new experimental non-destructive test method where step increasing voltage is applied to a cable conductor while electronically monitoring for an indication of insulation weakness at the applied voltage level. On August 5, 1997, a partial discharge test to a 9kV voltage level phase to ground, which is 113% of nominal operating voltage, was performed with no indications of partial discharge detected. On March 11, 1999, another partial discharge test to 16 kV, which is >200% of operating voltage was performed. This time partial discharge was observed on four of the six cables with the lowest indication observed at 113.5% of operating voltage. At the close of this inspection, the inspectors and the applicant were unsure if the results of the first two tests indicated cable insulation deterioration due to aging. The inspectors were told that the applicant was procuring replacement cable as a contingency for future replacement needs.

Subsequent to this inspection, on August 6, 1999, another partial discharge test was performed to 16kV and the reported results were similar to the results of the second test. The lowest partial discharge indication was 121.1% observed on the same cable which was lowest in the second test. Therefore these test results did not indicate a negative trend of cable degradation.

c. <u>Conclusions</u>

Based on the inspectors observations ,the team agrees with the applicant that for Phase Bus, Switchyard Bus, Insulators, and Transmission Conductors, no aging effects are applicable and no aging management program is required. However, for electrical cables and connections, the findings of the inspection team do not support the conclusion in the ONS LRA that there are no applicable aging effects for cables and connections and no aging management is required. Based on the results from the walkdowns conducted by the inspection team, the more extensive 1996 Duke walkdowns and a review of the documented operating experience (PIPs) for cables and connections, the inspection team believes that cables and connections at ONS are experiencing applicable aging effects as discussed in the LRA. The NRC team could not agree with the applicant's conclusion that no aging management program is needed for electrical cables and connectors.

E8.5 Review of Open Items

During the ONS license renewal scoping and screening inspection the team determined that the applicant had based its cable material evaluations on the cable types identified in Oconee and Keowee Cable Tabulation Drawings which did not contain all cable types included in the Oconee and Keowee cable databases. Problem Investigation Process (PIP) 99-1737 was written for resolution.

The applicant completed the Oconee Cable Type Database Review Project which included a review of the following sources to determine all cable type data for Oconee:

Oconee and Keowee Cable Tabulation Drawings
Keowee and Oconee Cable Databases
Duke Power PreFabricated Cable Report
Oconee Vendor Document Index
Oconee Cable Purchase Requisitions and Purchase Orders
Oconee Cable Transfer Records
Oconee 1E Cable Traceability Records
Oconee Cable Specifications
Duke Power Cable Sizing Engineering Criteria Manual
Duke Power Cable Mark Nos. Ampacity Design Criteria Manual.

The Oconee Cable Type Database Review Project identified fourteen cable types which were not included in the ONS license renewal cable material evaluation contained in ONS LRA electrical specification OSS-0274.00-00-0006, revision 1, "Oconee Electrical Component Aging Management Review For License Renewal." The fourteen additional cable types contained four materials which had not been previously evaluated in the ONS LRA electrical specification. The four new materials were polypropylene, teflon, tefzel, and vinyl. The Oconee Cable Type Database Review Project data search for additional cable types was a comprehensive review. The applicant performed an engineering evaluation of the four additional materials. The results were contained in Memorandum: W. M. Denny to R. P. Colaianni, dated June 30, 1999, "Additional Cable Insulation Materials at Oconee." The results of the review project were that the original conclusions of the ONS LRA electrical specification OSS-0274.00-00-0006, revision 1, were not changed.

The team verified that the three cable mark number types identified during the scoping and screening inspection as not being listed in the ONS and Keowee cable tabulation drawings were included in the review project database. The team reviewed the material evaluation for the additional cable materials and determined that the new materials were evaluated consistent with the process performed for the original cable material evaluations included in electrical specification 0SS-0274.00-00-0006, revision 1. The team concluded that the new material evaluations did not identify any cable material applications which were more limiting than the previous evaluations or that would be unsuitable for the period of extended operation. The applicant had completed the evaluation of the additional cable types but the results of the evaluations contained in the June 30, 1999, memorandum have not yet been incorporated into the ONS LRA documents. The Oconee and Keowee cable tabulation drawings have not yet been updated with the new data and PIP 99-1737 remains open.

## II. Management Meetings

### Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on July 30, 1999 Proprietary information was reviewed during this inspection and identified as such by the applicant to the inspectors, however, no proprietary information is included in this report.

### Partial List of Persons Contacted

Applicant

L. Nicholson, Regulatory Compliance manager
P. Colaianni, License Renewal
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
R. Gill, License Renewal
W. McCollum, Site Vice President, Oconee Nuclear Station
R. Nader, License Renewal
D. Ramsey, License Renewal
G. Robison, License Renewal

NRC

D. Billings, Resident Inspector
E. Christnot, Resident Inspector
S. Freeman, Resident Inspector
V. McCree, Deputy Director, Division of Reactor Safety, RII
J. Sebrosky, Project Manager, RLSB, NRR

Other licensee employees contacted during the inspection included engineers, operators, regulatory compliance personnel, and administrative personnel.

### Inspection Procedures Used

IP 71002: License Renewal Inspection Procedure

**Partial List of Documents Reviewed**

Application for Renewed Operating Licenses, Exhibit A, License Renewal - Technical Information, OLRP-1001

License Renewal Flow Diagrams, OLRP-1002

Oconee Nuclear Station Updated Final Safety Analysis Report (UFSAR)

NRC Safety Evaluation Report related to license renewal of Oconee Nuclear Station, Units 1, 2, and 3, June 1999

Specification OSS-0274.00-00-0003, “Oconee Reactor Building Containment Aging Management Review for License Renewal,” Rev. 1. March 3, 1997.

Specification OSS-0274.00-00-0004, “Oconee Reactor Coolant System Aging Management Review for License Renewal,” Rev. 0.

Specification OSS-0274.00-00-0005, “Oconee Mechanical Component Aging Management Review Specification Screening for License Renewal”, Rev. 1

Specification OSS-0274.00-00-0006, “Oconee Electrical Component Aging Management Review For License Renewal,” Rev. 1, April 9, 1999.

Oconee Electrical Cable Drawings OEE-14 through OEE 14-14

Keowee Electrical Cable Drawing KEE- 40-2 through KEE-40-6

Duke document: Summary of Duke Electrical Walkdowns at Oconee (February, March, August, November, 1996)

Duke document: Oconee Electrical Cable Guidance Document

Contractor Memorandum: W. M. Denny to R. P. Colaianni, dated 6/30/99, “ Additional Cable Insulation Materials at Oconee”

Contractor Memorandum: W. M. Denny to R. P. Colaianni, dated 7/26/99, “Cables Subjected to Water in the Turbine Building Cable Trench (Submerged Cables Test Data)”

Contractor Memorandum: W. M. Denny to R. P. Colaianni, dated 7/22/99, “ The Effects of Boric Acid Solution on Cable Insulation”

Duke document: Oconee/Kewoee Underground Cable Partial Discharge Tests, dated 6/10/99

Duke document: PVC Cables Found in Cable Tray over the Feedwater Line in Units 1, 2, and 3 Reactor Building, dated 7/26/99

DOE Cable Aging Management Guide, SAND96-0344

Duke document: Oconee Cable Type Database Review Project

Chemistry Manual 3.8, “Secondary Lab Sampling Frequencies, Specifications, and Corrective Actions,” Rev. 12

Chemistry Manual 3.10, “Primary Lab Sampling Frequencies, Specifications, and Corrective Actions,” Rev. 15

Oconee Nuclear Station, January - May 1999 Primary Chemistry Data Review Meeting, issued as Memorandum to File dated July 6, 1999 (File: OS-709.00)

Oconee Nuclear Station, January - May 1999 Secondary Chemistry Data Review, issued as Memorandum to File dated July 6, 1999 (File: OS-709.00)

Report BAW-2270, “The B&W Owners Group Generic License Renewal Program, Non-Class 1Mechanical Implementation Guideline and Mechanical Tools,” Rev. 1

Report BAW-2248, “Demonstration of the Management of Aging Affects for the Reactor  Vessel Internals”

Report BAW-2244A, “Demonstration of the Management of Aging Affects for the Pressurizer”

Report BAW-2251, “Demonstration of the Management of Aging Affects for the Reactor Vessel”

Calculation OSC-6892, “Aging Effects in Treated Water Systems Within the Scope of License Renewal,” Rev. 1, with Addendum 4

Calculation OSC-7380, “CCW Intake and Discharge Piping 5 Year Civil Coating Inspection”

“Third Interval Inservice Inspection Plan, Oconee Nuclear Station Units 1, 2, and 3 and Keowee Hydro Station Units 1 and 2,” Rev. 4

Procedure NDE-960, “Ultrasonic Examination of High Pressure Injection System Piping Welds and Base Metal Material at Oconee Nuclear Station,” Rev. 1

Procedure NDE-600, “Ultrasonic Examination of Similar Metal Welds in Ferritic and Austenitic Piping, Rev. 12

Procedure NDE-105, “ Radiographic Examination of Oconee Nuclear Station Thermal Sleeves,” Rev. 3E8.3

Engineering Support Program “Basis Document Fire Protection Program”, Revision 0

Engineering Support Program “Piping Erosion/Corrosion Program”, Revision 1

Service Water Piping Corrosion Program, Revision 1, dated November 1, 1995

Calculation OSC-4488, Revision 5, Unit 3 LPSW Benchmark

OP/0/A/1102/028, Rev. 2, “Reactor Building Tour”

OP/0/B/1106/033 “Primary System Leakage Identification”

PT/1/A/0600/010 “Reactor Coolant  Leakage”

PT/1/A/0600/012, Revision 057, Turbine Driven Emergency Feedwater Pump Test

PT/1/A/0600/013, Revision 038, Motor  Driven Emergency Feedwater Pump Test

PT/1/A/0230/015, Revision 005, High Pressure Injection Motor Cooler Flow Test

PT/2/A/0251/023, Revision 8, LPSW System Flow Test

PT/0/A/2200/010, Revisions 021and 022, KHS Fire Protection Equipment Surveillance

PT/0/A/2200/012, Revisions 14, 16 and 18, Fire Protection Pump and Mulsifyre Systems Wet Surveillance

MP/0/A/1705/037, Revision 004, Fire Protection - Strainer - Grinnell - Removal, Cleaning, and Installation

MP/0/A/2000/075, Revision 000, KHS Oil Sampling

NRC RAI 4.3.8-1, Preventive Maintenance Activity Assessment, and applicant’s response

NRC RAI 4.3.8-8, One time assessment of PM activities, and applicant’s October 29, 1998 and December 14, 1998 responses

April 7, 1999, NRC-Duke meeting minutes relating to PM program.

OMCS-0170.02, Rev. 15, Oconee Nuclear Station Maintenance Coating Schedule Manual

Duke document: Nuclear Coating Maintenance Manual, Rev. 13, 5/17/99

Duke document: Field Coating Maintenance Manual

Specification OSS-0101.00-00-0002, Duke Power Company Oconee 1-3 Coating Materials Required for Field Painting of Condenser Cooling Water Pipe

Engineering Support Program, “CCW Intake and Discharge Pipe Coating”

Specification OSS-101.00-00-0000, Condenser Cooling Water Intake and Discharge Pipe Specification

Duke document: Model Work Order for inspection of CCW Intake and Discharge Piping

Procedure QAC-3, “Inspection of Field Applied Coatings”

ONS Nuclear Policy Manual, Nuclear System Directive 208, Problem Investigation Process (PIP)

Duke document: 1993, 1994, and 1995 Eddy Current Results for Component Coolers.

Duke document: “ONS Service Water Piping Inspection Program Manual,” Revision 1.

## List of Acronyms

ANSI - American National Standards Institute
ASME - American Society of Mechanical Engineers
ASW - Auxiliary Service Water
BS - Reactor Building Spray System
BWST - Borated Water Storage Tank
CC - Component Cooling System
CCW - Condenser Circulating Water
CF - Core Flood System
CLB - Current Licensing Basis
CRDM - Control Rod Drive Mechanism
E/C - Piping Erosion Corrosion Program
ECT - Eddy Current Testing
EFW - Emergency Feedwater
FW - Feedwater System
HPI - High Pressure Injection
ISI - Inservice Inspection
kV - Kilovolt
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LOCA - Loss of Coolant Accident
LPSW - - Low Pressure Service Water
LRA - License Renewal Application
NRC - Nuclear Regulatory Commission
NRR - NRC office of Nuclear Reactor Regulation
NSD - Nuclear Station Directive
ONS - Oconee Nuclear Station
PIP - Problem Investigation Process
PM - Preventive Maintenance
RAI - Request for Additional Information
RCM - Reactor Coolant Makeup
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
SER - Safety Evaluation Report
SSF - Standby Shutdown Facility
UFSAR - Updated Final Safety Analysis Report
UT - Ultrasonic Testing

ATTACHMENT 1
OCONEE NUCLEAR STATION PROBLEM INVESTIGATION PROCESS (PIP)
REVIEW FOR CABLE AND CONNECTORS

TEMPERATURE EFFECT PIPS

| | | | | | |
|---|---|---|---|---|---|
| 96-0605 | 96-1042 | 96-1044 | 96-2513 | 96-2514 | 96-2515 |
| 96-2516 | 96-2518 | 96-2519 | 96-2523 | 97-0356 | 97-2455 |
| 97-3356 | 97-4303 | 98-5144 | | | |

MOISTURE/BORIC ACID EFFECT PIPS

| | | | | | |
|---|---|---|---|---|---|
| 94-0447 | 94-1680 | 95-0058 | 96-2415 | 96-2499 | 97-0102 |
| 97-1627 | 98-2483 | 98-2538 | 98-5254 | 98-5591 | 98-6050 |

CONNECTOR PIPS

| | | | | | |
|---|---|---|---|---|---|
| 93-1077 | 95-1387 | 97-1236 | 97-2994 | 97-4558 | 98-3685 |

KEOWEE UNDERGROUND CABLE PIPS

| | |
|---|---|
| 95-0611 | 95-0947 |

NON-AGING CABLE/CONNECTOR PIPS

| | | | | | |
|---|---|---|---|---|---|
| 94-0435 | 96-1676 | 97-0359 | 97-0430 | 98-0957 | 98-1615 |
| 98-2533 | 98-3270 | 98-3808 | 99-0288 | 99-0354 | 99-0478 |
| 99-0530 | 99-0787 | 99-1153 | 99-1179 | 99-1439 | 99-1495 |
| 99-1585 | 99-2287 | 99-2621 | 99-2676 | 99-2679 | 99-2680 |
| 99-2688 | 99-2800 | 99-2857 | 99-2946 | | |