

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos: 50-269, 50-270, 50-287, 72-04

License Nos: DPR-38, DPR-47, DPR-55, SNM-2503

Report No: 50-269/97-15, 50-270/97-15, 50-287/97-15

Licensee: Duke Energy Corporation

Facility: Oconee Nuclear Station, Units 1, 2, and 3

Location: 7812B Rochester Highway  
Seneca, SC 29672

Dates: October 19 - November 15, 1997

Inspectors: M. Scott, Senior Resident Inspector  
S. Freeman, Resident Inspector  
E. Christnot, Resident Inspector  
D. Billings, Resident Inspector  
B. Crowley, Regional Inspector (Section M1.4)  
J. Blake, Regional Inspector, Review at Eddy Current  
Analysis Center (Sections M1.6 and M2.2)  
N. Economos, Regional Inspector (Section M2.3)  
R. Franovich, Resident Inspector, Catawba (Section M1.7)  
R. Moore, Regional Inspector (Sections E2.1, E3.1, and E8.1)  
N. Merriweather, Regional Inspector (Sections E2.1, E3.1,  
and E7.1)  
D. Forbes, Regional Inspector (Sections R1 through R7)  
B. Miller, Regional Inspector (Sections F1 through F7)

Approved by: C. Ogle, Chief, Projects Branch 1  
Division of Reactor Projects

Enclosure 2

9712310358 971215  
PDR ADOCK 05000269  
G PDR

## EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3  
NRC Inspection Report 50-269/97-15,  
50-270/97-15, and 50-287/97-15

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a four-week period of resident inspection, and the results of announced inspections by region-based inspectors.

### Operations

- In general, the conduct of operations was professional and safety conscious. (Section 01.1)
- Refueling activities were completed in a professional and conservative manner. The use of the reactor engineer on the refueling bridge in the reactor building, the use of an extra licensed operator in the spent fuel pool area during refueling, and the new level of licensee safety conscious overview were strengths. (Section 01.2)
- The licensees power reduction and replacement of a degrading Unit 2 main seal oil pump was proactive and performed without incident. (Section 02.1)
- The inspectors concluded that the licensee's program and preparations for cold weather were good. (Section 02.2)

### Maintenance

- The inspectors concluded that general maintenance activities were completed thoroughly and professionally. (Section M1.1)
- During the period, the licensee searched for and found a missing piece from the 1A1 Reactor Coolant Pump impeller. During the search, the licensee found other reactor vessel related pieces that had been missing since 1981. The licensee was generating an evaluation on the vessel related piece that would remain in place. Video inspection of the Unit 1 reactor coolant pumps had been performed and the licensee was evaluating continued operations of the three pumps with observed impeller degradation for an additional fuel cycle. (Section M1.2)
- Strong management oversight, good communications, and sound coordination by engineering and maintenance resulted in an error free recovery of a broken MARBO stopple plug from the low pressure service water system. (Section M1.3)
- The Failure Investigation Process team was aggressively pursuing the root cause for the failure of the MARBO plugging tool. All maintenance

and inspection activities observed for installation of the 24-inch MARBO plug were performed in a conscientious manner by qualified personnel in accordance with detailed procedures. Welding and non-destructive examination activities observed and reviewed were performed in accordance with the applicable code and procedure requirements. (Section M1.4)

- The failure by maintenance personnel to complete a Technical Specification required surveillance on low pressure injection flow instruments resulted in a violation. (Section M1.5)
- The licensee's process for the evaluation of steam generator eddy current data was being conducted in accordance with current industry guidelines and expectations. (Section M1.6)
- The practice of obtaining an oil sample from the Unit 2 turbine driven emergency feedwater pump without it running was a weakness in the oil sampling methodology. A request by operations for a procedure to govern the realignment of the pump's steam supply was seen as a conservative measure to protect the steam header piping and structural supports from possible water and steam hammers. (Section M1.7)
- Assembly of low pressure service water valves with the wrong parts resulted in an Unresolved Item concerning parts identification. (Section M2.1)
- The condition of the Ocone once-through-steam-generators has seen additional licensee attention through Babcock & Wilcox Owners Group sponsored tube pulls in each unit, and the contract with Dominion Engineering Incorporated to do an independent review of the Ocone steam generator program. (Section M2.2)
- The failures of mechanical feedwater piping connections to the Unit 1B steam generator were not being identified and trended as repeat failures. (Section M2.2)
- The licensee implemented repairs in once-through-steam-generator 1B tubes in a conservative manner, following administrative controls and applicable controlling procedures. Technical support provided good guidance and oversight while the activity was in progress. (Section M2.3)

### Engineering

- Based on a review of engineering activities, engineering support to operations and maintenance was adequate. (Section E2.1)

- Design control for a Unit 1 low pressure service water modifications was good. The 10 CFR 50.59 evaluations were detailed and thorough. (Section E3.1)
- The engineering self-assessments performed in 1997 were effective in identifying and assuring correction of deficiencies in engineering performance. (Section E7.1)
- The failure to revise the Updated Final Safety Analysis Report to reflect different fuel enrichments since 1994 was identified as a violation. The discrepancy had been previously identified, but went uncorrected. (Section E8.3)

#### Plant Support

- Based on observations and procedural reviews, the inspectors determined the licensee was effectively maintaining controls for radioactive waste and waste processing. One unresolved item was identified to determine monitoring requirements for radiological work in two onsite buildings. The licensee's initiative to improve resin sluice processing systems to maintain exposures As Low As Reasonably Achievable and to improve environmental controls for resin sluicing was viewed as a strength. (Section R1.1)
- It was concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented, for those parameters reviewed, in accordance with the Technical Specification requirements and the Station Chemistry Manual for Pressurized Water Reactor water chemistry. (Section R1.2)
- The inspectors determined that the licensee had effectively implemented a program for shipping radioactive materials required by NRC and Department of Transportation regulations. (Section R1.3)
- It was concluded that the meteorological instrumentation had been adequately maintained and that the meteorological monitoring program had been effectively implemented. (Section R2.1)
- The inspectors determined that the licensee was performing Quality Assurance audits and effectively assessing the radiation protection program as required by 10 CFR Part 20.1101. The inspectors also determined that the licensee was completing corrective actions in a timely manner. (Section R7.1)
- The licensee's fire protection staff demonstrated an aggressive attitude in the identification and correction of fire protection deficiencies. (Section F1.1)

- Three non-cited violations were identified for the licensee's failure to meet the fire protection operability requirements for three required fire protection features. (Section F1.1)
- The low number of inoperable or degraded fire protection components, in conjunction with the good material condition of the fire protection components and fire brigade equipment, indicated appropriate emphasis had been placed on the maintenance and operability of the fire protection equipment and components. (Section F2.1)
- Adequate surveillance and test procedures were provided for the fire protection systems and features, and implementation of the procedures was effective. (Section F2.2)
- The fire barrier penetration seals were functional. However, the licensee had implemented a project to provide documentation to identify the design specification and bounding test criteria applicable to each fire barrier penetration. (Section F2.3)
- In general, fire protection program implementing procedures were well written and met the licensee's commitments to the NRC requirements. Procedure implementation for the control of ignition sources and transient combustibles was good. Overall, general housekeeping was satisfactory. (Section F3.1)
- A violation was identified involving the failure to provide fire fighting strategies for all plant areas which contained safety-related equipment or presented an exposure hazard to safety-related components. (Section F3.1)
- The fire brigade organization and training met the requirements of the site procedures. The use of the fire brigade safety officer position during fire emergencies was identified as a program strength. (Section F5.1)
- Fire brigade performance during a drill conducted during this inspection period was mixed. Subsequent brigade performance after resolution of drill identified deficiencies was satisfactory. (Section F5.1)
- The 1995 audit and assessment of the facility's fire protection program were comprehensive and appropriate corrective action was promptly taken to resolve identified issues. (Section F7.1)

## Report Details

### Summary of Plant Status

Unit 1 began and ended the period in a scheduled refueling outage. Major outage work completed included the replacement of the 1A1 reactor coolant pump, inspection of the other reactor coolant pump impellers, and low pressure service water system modifications.

Unit 2 began the period at 100 percent power and decreased to 56 percent power on November 6, to repair the generator main seal oil pump motor. The unit returned to 100 percent power on November 7, and remained at 100 percent power for the rest of the period.

Unit 3 began and ended the period at 100 percent power.

### Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. Except for the issues discussed in Sections E8.3 and F, the inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

## I. Operations

### 01 Conduct of Operations

#### 01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

#### 01.2 Unit 1 Refueling Activities

##### a. Inspection Scope (71707)

The inspectors observed portions of the defueling and refueling activities for Unit 1.

##### b. Observations and Findings

The inspectors observed control room, spent fuel pool (SFP), and reactor building (RB) activities by operations personnel. The activities were conducted in a professional manner with emphasis on attention to detail, conservative judgement, and timeliness. During the initial checkout of equipment, problems with the RB manipulator were identified and resolved. The licensee made enhancements in refueling activities

including the use of a reactor engineer on the refueling bridge in the RB and the use of an extra licensed operator in the SFP area during refueling. Licensee management also articulated a new level of licensee safety conscious overview for refueling. The inspector observed that operators in the control room were aware of the movement of each fuel assembly by number and monitored appropriate nuclear instrumentation.

c. Conclusions

Refueling activities were completed in a professional and conservative manner. The use of the reactor engineer on the refueling bridge in the RB, the use of an extra licensed operator in the SFP area during refueling, and the new level of licensee safety conscious overview were strengths.

02 Operational Status of Facilities and Equipment

02.1 Unit 2 Power Reduction for Seal Oil Motor Replacement

a. Inspection Scope (71707, 62707)

The inspectors attended several meetings and observed work in progress as the licensee reduced power to replace the Unit 2 seal oil pump motor.

b. Observations and Findings

On November 6 and 7, 1997, the licensee evaluated a degrading bearing on the main seal oil pump motor. Routine vibration monitoring detected higher than expected vibration levels on the motor, which worsened over November 6. After a management meeting on the afternoon of November 6, the licensee reduced power on Unit 2 to 56 percent. As the down power continued, maintenance personnel removed the equivalent motor from Unit 1, which was shut down for refueling, and overhauled it by replacing the bearings. The switch between seal oil skid pumps was safely performed and the main pump motor was changed out using the overhauled pump from Unit 1. The unit was restored to full power on November 7.

c. Conclusions

The licensee's power reduction and replacement of a degrading Unit 2 main seal oil pump were proactive and performed without incident.

## 02.2 Cold Weather Preparations

### a. Inspection Scope (71714)

The inspectors reviewed the licensee's program for cold weather preparations and the status of freeze protection equipment.

### b. Observations and Findings

The inspectors documented in Inspection Report (IR) 50-269,270,287/96-16 previous work orders and discrepancies involved with freeze protection equipment. The IR indicated the following: a corporate audit was performed to formalize a freeze protection program for all three nuclear sites; Problem Identification Process (PIP) report 096-0639 was initiated to address concerns raised by the audit; and procedure upgrades that are planned or being evaluated by site management were discussed. In addition, the IR also identified three susceptible areas: (1) the borated water storage tank (BWST) level indication; (2) the elevated water storage tank (EWST) level indication; and (3) the cooling water to the condenser circulating water (CCW) pumps.

The inspectors reviewed PIP 096-0639 and observed that several corrective actions were initiated. Among the items affected by the corrective actions were: plant equipment used for freeze protection, such as heat trace and heaters; areas of the plant and equipment requiring cold weather protection, including Keowee; and administrative control, inspection, and maintenance procedures required to implement a freeze protection program.

The inspectors reviewed applicable procedures and observed the following:

- IP/0/B/1606/009, Preventive Maintenance and Operational Check of Freeze Protection, Revision 0, provided a method for inspecting, cleaning, and performing an operational check of freeze protection equipment.
- Nuclear System Directive (NSD) 317, Freeze Protection Program, Revision 1, provided the guidelines and requirements to ensure that sub-freezing conditions do not impair the safe and efficient operation of nuclear power plant equipment.
- MP/0/B/3007/059, Plant Heater - Testing, Revision 1, provided guidance for the testing of plant heaters.

The inspectors observed and reviewed work activities involved with procedure IP/0/B/1606/009. These activities were performed on freeze



protection equipment associated with the BWST, EWST, and the CCW cooling water supply.

c. Conclusions

The inspectors concluded that the licensee's preparations and program for cold weather were good.

03 Operations Procedures and Documentation

03.1 Failure to Perform Instrument Surveillance on the Inadequate Core Cooling Monitor (ICCM)

a. Inspection Scope (71707)

On October 29, 1997, during the performance of PT/3/A/0600/01, Periodic Instrument Surveillance, operations identified that Technical Specification (TS) requirements had not been met due to the operator aid computer (OAC) subcooling monitor calculation being non-conservative.

b. Observations and Findings

TS 1.5.3 requires an instrument channel check to verify acceptable instrument performance by comparison to an independent channel measuring the same variable. To meet this requirement for the ICCM, PT/3/A/0600/01 required the operator compare the ICCM subcooling values with the OAC subcooling values. PIP 097-1394 was initiated on April 30, 1997, to document a problem with the coefficients used in the OAC subcooling monitor calculation. The operators had been initialing the step in PT/3/A/0600/01 with a note stating that the OAC points were out of service. This did not meet the intent of the TS surveillance. As an interim corrective action, engineering developed a procedure to allow operators to perform a manual calculation using control room instrument values to verify the subcooling margin. The inspectors will continue to follow the licensee's evaluation through Licensee Event Report (LER) 50-287/97-04 and the associated PIP 097-3784 concerning TS surveillance requirements.

## II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

The inspectors observed all or portions of the following maintenance activities:

- TT/1/A/0400/28 Standby Shutdown Facility Reactor Coolant Makeup Pump Flow Distribution
- WO 97092286-01 Unit 1 Perform Video Inspection of Reactor Core Support Area
- PT/1/A/0610/01J Emergency Power Switching Logic Functional Test
- IP/0/B/1606/009 Preventive Maintenance and Operational Check of Freeze Protection
- MP/0/A/3007/059 Plant Heater - Testing
- IP/0/A/3000/015 125 Volt Direct Current 230 Kilovolt Switchyard Battery Service Test and Annual Surveillance
- WO 97062732-1 Perform Annual Switchyard Battery Surveillance

b. Observations and Findings

The inspectors found the work performed under these activities to be professional and thorough. All work observed was performed with the work package present and in use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress. Quality control personnel were present when required by procedure. When applicable, appropriate radiation control measures were in place.

c. Conclusion

The inspectors concluded that the maintenance activities listed above were completed thoroughly and professionally.

M1.2 Unit 1 Reactor Coolant Pump (RCP) Impellers and Loose Parts in Reactor Coolant System (RCS)

a. Scope of Inspection (62707, 37551)

As discussed in IR 50-269,270,287/97-014, Section M1.9, the licensee found a piece of the vane missing from the 1A1 RCP impeller. The inspectors followed the licensee's actions and were informed that these actions will be captured in PIP 097-4012.

b. Observations and Findings

The licensee inspected the RCS and reactor vessel to the maximum extent practicable to locate the missing piece. The piece was found in the bottom of the reactor vessel. Additionally, the licensee found a

thermal shield bolt head and a core support assembly guide block which were previously reported missing. These parts were discussed in LER 50-269/81-11. The LER included supporting documentation from the RCS vendor Babcock & Wilcox, to justify continued operation. The impeller piece and bolt were removed. The guide block was firmly wedged between the core support assembly rib section and the incore guide support plate. The licensee was in the process of completing an evaluation of the observed conditions at the end of the report period. To date, the licensee's retrieval actions have been adequate.

The licensee inspected the impellers on the three remaining RCPs for potential cavitation induced erosion. The licensee contracted with a vendor for an articulated, high-resolution camera that could completely inspect the details of the impellers, particularly the back side of each impeller vane. All three impellers had indications of erosion damage that was to be documented in PIP 097-4012. The inspectors viewed the video tape made during the inspection and discussed the findings with the licensee and other NRC personnel. The licensee and the pump vendor were evaluating the damage at the end of the inspection period.

### M1.3 Low Pressure Service Water (LPSW) MARBO Stopple Plug Failure

#### a. Inspection Scope (62707,40500)

The inspectors reviewed documents and drawings, interviewed personnel, and observed activities associated with the failure and subsequent recovery of a 36-inch MARBO stopple plug in the LPSW piping.

#### b. Observations and Findings

On October 17, 1997, while removing the 36-inch MARBO stopple plug, a loud knock was heard at the stopple machine and a water and oil mixture was observed coming from the view port. Licensee personnel quickly reacted to contain the oil and prevent a oil discharge to the lake. Vendor personnel, with licensee approval, continued to attempt to remove the stopple plug and close the 36-inch isolation valve. The valve closed smoothly to the halfway point and stopped. The valve was cycled and again an attempt was made to remove the stopple plug. The valve would not close fully and the coordinator entered the stopple plug loss contingency plan. A Failure Investigation Program (FIP) team was formulated to determine the cause and PIP 097-3621 was generated.

On October 20, 1997, a video was completed by the vendor of the inside of the valve. The video showed that the stopple plug was separated from the ram assembly used to position the plug. The break was located at the point where the ram met the pivot plate. The contingency plan to remove the broken stopple plug was discussed with management. A modification package, TN/1/A/11029/00/01M, for performance of another

MARBO plug to allow recovery of the 36-inch plug was completed on October 23, 1997. The new 24-inch MARBO connection was completed on October 26, 1997. The 24-inch MARBO plug was installed on October 27, 1997, with the subsequent recovery of the 36-inch MARBO plug and the removal of the 24-inch MARBO plug on October 28, 1997.

The broken 36-inch MARBO plug was sent to Southwestern Research Institute for metallurgical analysis.

c. Conclusions

Strong management oversight, good communications, and sound coordination by engineering and maintenance resulted in an error free recovery of a broken MARBO stopple plug from the LPSW system.

M1.4 LPSW Piping Modification

a. Inspection Scope (62700)

The inspectors observed ongoing work activities relative to installation of a stopple (MARBO) plug in a 24-inch diameter LPSW pipe. See paragraph M1.3 for further discussion on problems encountered with a 36-inch MARBO plug upstream of the 24-inch plug, which necessitated the installation of the 24-inch plug.

b. Observations and Findings

As discussed in paragraph M1.3, while removing a stopple (MARBO) plug from the 36-inch LPSW line downstream of the C LPSW pump, the plugging machine hydraulic ram broke before the plugging head was completely removed from the split tee fitting and sandwich valve. The sandwich valve could not be closed to isolate the plugging machine from the system. Therefore, another MARBO plug was installed in the 24-inch line downstream of the 36-inch plug to isolate the plug so that the broken ram and plugging machine could be removed from the 36-inch line. The inspectors observed the following activities relative to investigation of the cause of the ram failure for the 36-inch plug and installation of the 24-inch plug:

Failure Investigation

A failure investigation had been initiated by a FIP team. The inspectors discussed the failure with the FIP team leader and reviewed the preliminary results of the investigation. The ram broke near the end-cap weld at the attachment to the plugging head. Based on pictures taken with a remote camera prior to removal of the plugging machine, the FIP team stated that the failure appeared to be fatigue in nature. A

metallurgical analysis was planned after removal of the plugging machine.

#### Installation of 24-inch Plug

The 24-inch MARBO plug was installed by Minor Modification Project Numbers ONOE-11028 and ONOE-11029. The applicable code for fabrication and installation of the split tee was USA Standard Code for Pressure Piping B31.1, July 1967 Edition. In addition to reviewing the modification packages and various in-process work procedures and documents, the inspectors observed and reviewed the following welding and inspection activities:

- In-process welding was observed for Weld 6 (flange to split tee) on Isometric Drawing 1-LPS-570. In addition, in-process final visual and magnetic particle examinations were observed for the weld.
- Final weld surfaces were visually inspected on the split-tee Welds 2, 3, 4 and 5 on Isometric Drawing 10LPS-570.
- For Welds 2, 3, 4, 5, and 6 on Isometric Drawing 10LPS-570, weld process control sheets and weld material issue records were reviewed; and welder qualification, welding material certification, and nondestructive examination/quality control (NDE/QC) inspector qualifications were verified.

#### c. Conclusions

The FIP team was aggressively pursuing the root cause for the failure of the MARBO plugging tool. All maintenance and inspection activities observed for installation of the 24-inch MARBO plug were performed in a conscientious manner by qualified personnel in accordance with detailed procedures. Welding and NDE activities observed and reviewed were performed in accordance with the applicable code and procedure requirements.

#### M1.5 Low Pressure Injection Flow Instrument Surveillance Interval Exceeded

##### a. Inspection Scope (62707)

The inspectors interviewed licensee personnel and reviewed documents and work orders associated with the low pressure injection (LPI) system flow instrumentation surveillances.

b. Observations and Findings

On October 7, 1997, the inspectors requested documentation to verify the testing of the LPI system. On October 10, 1997, with Unit 1 in a refueling outage, Unit 2 at 100 percent power, and Unit 3 in hot shutdown, the licensee identified that the surveillance for the flow transmitters had not been completed on Unit 1 since January 26, 1995, and on Unit 3 since February 1, 1995.

The procedure containing this calibration had been performed on Unit 1 and 3, but only the calibration of the differential pressure indicator had been performed. The complete surveillance, including the flow transmitters, had been completed for Unit 2 on July 21, 1997. Following identification of the omission, the complete calibration procedure was completed for Unit 1 on October 11, 1997, and for Unit 3 on October 10, 1997, with no discrepancies noted.

An investigation was initiated to verify no other omissions of TS surveillances. PIP 7-097-3465 and LER 50-269/97-09 were generated. The investigation revealed no other missed TS surveillances. The root cause was identified as failure to follow procedure. The surveillance had been scheduled, but the technicians did not perform the procedure as specified. Failure to complete required TS surveillances is a violation (VIO) of TS requirements and is identified as VIO 50-269,287/97-15-01: Failure to Complete Required TS Surveillances on LPI Flow Instruments.

c. Conclusions

The failure by maintenance personnel to complete a Technical Specification required surveillance on low pressure injection flow instruments resulted in a violation.

M1.6 Steam Generator (SG) Eddy Current Examinations

a. Inspection Scope (50002)

The inspector reviewed the licensee's program and procedures for eddy current analysis, and observed the activities of the resolution analyst team for the Oconee 1 outage, which commenced on September 18, 1997. The procedures reviewed were as follows:

- NDE-701, Multifrequency Eddy Current Examination of Steam Generator Tubing at McGuire, Catawba, and Oconee Nuclear Stations, Revision 3, Field Change 97-09, September 9, 1997.
- NDE-703, Evaluation of Eddy Current Data for Steam Generator Tubing, Revision 5, Field Change 97-10, September 9, 1997.

- NDE-707, Multifrequency Eddy Current Examination of Non-ferrous Tubing, Sleeves and Plugs Using a Motorized Rotating Coil Probe, Revision 3, Field Change 97-13, September 16, 1997.
- NDE-708, Evaluation of Eddy Current Data for Non-ferrous Tubing, Sleeves and Plugs Using a Motorized Rotating Coil Probe, Revision 3, Field Change 97-11, September 9, 1997.
- Data Management/System Administration Guidelines - Oconee Unit 1 End of Cycle-17 (EOC-17), Revision 0, September 17, 1997.
- Eddy Current Guidelines, Oconee Nuclear Station, Unit 1, EOC-17, Revision 0, September 17, 1997.

The licensee's eddy current data evaluation facility is located on the grounds of the McGuire Nuclear Station, near Charlotte, North Carolina (NC). For the Oconee Unit 1 SG eddy current examinations the primary analysts were working in Lynchburg, Virginia (VA), and the secondary and resolution analysts were working at the licensee's facility.

b. Observations and Findings

As required by the licensee's program, eddy current data were being analyzed by two independent groups of analysts, referred to as the primary and secondary analysts, with differences between the two resolved by independent resolution analysts. The primary analysts for this Oconee Unit 1 outage were working at the Framatome facility in Lynchburg, VA, and the secondary and resolution analysts were working at the licensee's facility at the McGuire site.

The inspector observed the activities of the resolution analysts during resolution of differences between the results of primary and secondary analyses. As a part of the resolution process, the analysts were able to bring past inspection data on the screen for direct comparison of previous signals with the current data.

c. Conclusions

The licensee's process for the evaluation of steam generator eddy current data was being conducted in accordance with current industry guidelines and expectations.

M1.7 Maintenance on Turbine-Driven Emergency Feedwater Pump (TDEFWP) Turbine Steam Supply Valves

a. Inspection Scope (61726)

A Unit 2 TDEFWP surveillance test was scheduled to be performed on October 28, 1997, and maintenance activities were scheduled to be performed the same day before pump testing. The inspectors reviewed surveillance test procedure PT/2/A/0600/12, Turbine Driven Emergency Feedwater Pump Test, Revision 53; reviewed maintenance procedure MP/0/A/1840/040, Pumps-Motors-Miscellaneous Components-Lubrication-Oil Sampling-Oil Change, Revision 6; reviewed operating procedure OP/2/A/1106/06, Enclosure 3.13, Isolation and Return of Main Steam Supply to the TDEFWP, written October 30, 1997; discussed the maintenance and testing activities with operations, maintenance, work control and engineering personnel; observed various maintenance and testing activities; reviewed the UFSAR, design basis documentation, and associated system drawings; and observed pre-job briefings and various operator actions in support of maintenance and testing activities in the control room.

b. Observations and Findings

At 5:32 a.m., on October 28, 1997, the Unit 2 TDEFWP was removed from service for planned maintenance in preparation for a quarterly TDEFWP surveillance test. Maintenance activities included analysis of the TDEFWP bearing oil and repair of 2SD-307, a drain valve in the main steam supply line to the pump turbine. In preparation for the repairs to the steam line drain valve, main steam to the TDEFWP was isolated; auxiliary steam from the Unit 3 main steam line was available.

Oil samples were obtained from the inboard and outboard pump bearing housings and analyzed; the results indicated that the sample was contaminated with suspended solids. A second sample was obtained and met acceptance criteria; the pump was declared operable (the remaining steam drain valve repair did not require that the TDEFWP be inoperable since auxiliary steam was available and at the required pressure).

To ensure that the pump bearings were unaffected, engineering personnel proposed running the pump to demonstrate that the bearings were not damaged and confirm the results of the second oil sample. Operations personnel had already returned the TDEFWP pump to service under the assumption that, since the second sample results met acceptance criteria, the pump was operable. Although the pump run proposed by the engineering personnel was a conservative measure to demonstrate pump operability, a miscommunication between the organizations resulted in a premature return to service of the TDEFWP. Station PIP 097-3797 was



initiated to address the discrepant oil samples and subsequent decision to test the pump bearings.

On October 29, 1997, a performance test of the TDEFWP was performed to demonstrate that the pump bearings were functional. The inspectors observed the pump start and run; no discrepancies were identified.

The inspectors questioned a maintenance supervisor why the initial oil sample was contaminated. Maintenance technicians initially had drawn the oil samples through a small piece of plastic tubing by inserting one end of the tubing into the bearing housing and using a hand-pump to transfer the sample from the housing through the plastic tube and into a sample bottle on the other end of the tube. Apparently, the end of plastic tubing had traveled along the inner wall of the bearing housing and disturbed a film of debris on the wall surface, which was drawn into the sample bottle. To obtain the second sample, maintenance technicians drained the oil from the bearing housings into a container. The oil was stirred, and a sample was taken from the mixed medium.

The inspectors determined that the initial oil sample had not been obtained after the pump had been run to ensure that the sample represented a well-mixed, homogenous population of oil. The inspectors reviewed maintenance procedure MP/0/A/1840/040, Pumps-Motors-Miscellaneous Components-Lubrication-Oil Sampling-Oil Change, Revision 6, and determined that the procedure did not require that the pump operate prior to sampling to ensure adequate mixing of the oil. The inspectors discussed sampling methodology with a maintenance supervisor, who indicated that sometimes pumps are run prior to oil sampling, but not always. The inspectors expressed concern that the practice of not running a pump, or other piece of equipment with components requiring oil lubrication, prior to obtaining an oil sample could fail to reveal contaminants in the sample and, thereby, contaminants in the population. The inspectors considered the practice a weakness in the oil sampling methodology.

The inspectors verified that the TDEFWP was restored to operable status within the time allowed by TS. The inspectors also observed portions of the maintenance to repair the steam leak on 2SD-307, which was completed on October 29, 1997. Operations personnel raised concerns with water/steam hammers associated with returning the isolated portion of main steam supply piping to service. Although this realignment had been performed in the past, it was not proceduralized and controlled to minimize the risk of water/steam hammers. Operations requested that a procedure be developed to govern the steam line's return to service. The procedure, OP/2/A/1106/06, Enclosure 3.13, Isolation and Return of Main Steam Supply to the TDEFWP, was developed on October 30, 1997. The inspector reviewed the procedure and identified no concerns. The steam line was returned to service without incident. The inspectors

considered the request for a procedure to govern the realignment a conservative measure to protect the piping and structural supports.

c. Conclusions

The inspectors considered the practice of obtaining an oil sample without running the associated equipment a weakness in the oil sampling methodology. The request for a procedure to govern the realignment of the Unit 2 TDEFWP steam supply was a conservative measure to protect the piping and structural supports.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Wrong Service Water Valve Parts

a. Scope of Inspection (61726)

During the inspection period, the licensee was rebuilding several valves in the LPSW system. The inspectors followed activities on two valves.

b. Observations and Findings

During re-assembly of valve 1LPSW-565, supply to reactor building auxiliary coolers, maintenance personnel observed that the new trunnion parts could not be installed properly. The trunnions connect the bottom and top of the ball valve to the operating shaft; thus allowing ball rotation/movement. The new trunnions were approximately 1/4-inch taller than the removed trunnions. PIP 097-4025 was initiated on November 11, 1997, the day of discovery.

Investigation indicated that the eight-inch trunnion parts intended for 1LPSW-565 had been installed into 1LPSW-4, the 1A LPI cooler outlet isolation valve, which was a ten-inch valve. This valve had been returned to service. The 1A train of LPI was declared inoperable and the 1B LPI train was available for service as required in Selected Licensee Commitment 16.5.6. Tentative licensee review indicated that the parts had been marked incorrectly and not detected prior to dispersal from the licensee's supply.

The eight-inch parts were removed from 1LPSW-4, examined and re-certified. The 10-inch parts were re-certified and installed in 1LPSW-4 and the eight-inch parts inspected and installed in 1LPSW-565. Both valves were tested and returned to service. As of the end of this period, the PIP and its attendant investigation were not complete. Unresolved Item (URI) 50-269,270,287/97-15-02, Valve Parts Identification Problem, is identified to track this issue.

c. Conclusions

Assembly of LPSW valves with the wrong parts resulted in an Unresolved Item concerning parts identification.

M2.2 Once-Through-Steam-Generators (OTSGs)a. Inspection Scope (50002)

During the week of September 8, 1997, the inspectors reviewed licensee and contractor reports related to the material condition of the Oconee OTSGs. The reports reviewed included the licensee's latest steam generator maintenance, outage summary reports for each of the units; a component health status determination report prepared by the licensee; a series of reports prepared by Dominion Engineering Incorporated (DEI) concerning the condition of the Oconee OTSGs; and Asea Brown Boveri Combustion Engineering test reports about eddy current and pressure testing of Unit 3 OTSG tubes pulled during the last outage.

b. Observations and FindingsLicensee Outage Summary Reports

The review of outage summary reports showed the following data concerning the number of tubes plugged during the last outage, why they were plugged, and the total number of tubes currently plugged in each OTSG.

	<u>Unit 1</u>		<u>Unit 2</u>		<u>Unit 3</u>	
	<u>EOC-16 (11/95)</u>		<u>EOC-15 (4/96)</u>		<u>EOC-16 (10/96)</u>	
	<u>SG 1A</u>	<u>SG 1B</u>	<u>SG 2A</u>	<u>SG 2B</u>	<u>SG 3A</u>	<u>SG 3B</u>
Dings	7	5	-	-	-	-
Erosion/Corrosion	17	47	0	6	23	13
Groove Intergranular Attack (IGA)	2	42	119	54	51	16

	<u>Unit 1</u>		<u>Unit 2</u>		<u>Unit 3</u>	
	<u>EOC-16 (11/95)</u>		<u>EOC-15 (4/96)</u>		<u>EOC-16 (10/96)</u>	
	<u>SG 1A</u>	<u>SG 1B</u>	<u>SG 2A</u>	<u>SG 2B</u>	<u>SG 3A</u>	<u>SG 3B</u>
Wear	4	1	8	14	2	5
% Through-Wall (TW)	27	36	11	43	3	9
Sleeve	1	0	0	0	1	-

Other	7	17	7	12	9	6
IGA or Precursor Groove IGA	-	-	5	29	-	-
IGA	-	-	47	55	26	42
Lane & Wedge	-	-	2	0	-	-
Upper Roll Transition	-	-	-	-	-	19
Total this Outage	65	148	199	213	115	110
Previous	334	1177	138	268	455	371
Total Plugged	399	1325	337	481	570	483
% This Outage	0.42%	0.95%	0.89%	1.37%	0.74%	0.71%
Total Tubes	15,531	15,531	15,531	15,531	15,459	15,531
% of Total Tubes	2.57%	8.71%	2.17%	3.10%	3.69%	3.11%

While the data from these reports indicate that OTSG 1B is in the poorer condition (8.71% plugged), the Units 2 and 3 OTSGs had a significant number of tubes plugged due to freespan axial indications. (The freespan axial indications are referred to as Groove IGA and IGA in the data set.)

The outage reports for Units 2 and 3 described tube pulls that were done as a result of a Babcock and Wilcox Owners Group (BWOOG) program to investigate free-span cracking, originally found in the Oconee Unit 1 OTSG. There were four full-length tubes removed from the 2A OTSG, and three full-length and two partial-length tubes pulled from the 3A OTSG. These tubes were in addition to the seven tubes pulled from the Oconee Unit 1 OTSG in 1994, where the free-span cracking (IGA/IGSCC) was initially confirmed.

#### Electrosleeving™ field trial

Other items of interest in the outage summary reports included the fact that during the Unit 1 outage in November 1995, Framatome Technologies conducted a field demonstration of the Electrosleeving™ process for electro-plating metallic Nickel on the inside surface of OTSG tubes to seal off existing defects and provide a barrier against further degradation. Nine tubes that were scheduled to be plugged were selected

and Electrosleeves™ were deposited at the first support plate. The Electrosleeving™ process was jointly developed by Framatome Technologies and Ontario Hydro Technologies. Oconee Unit 1 was the first field deployment of the system. The use of the process under field conditions, including processing of the electroplating solutions as contaminated, hazardous waste, was reported as a success. The condition of the tube and the resulting Nickel plating were not reported, in that the tubes were plugged after plating.

#### OTSG 1B Feedwater Nozzle Leakage

The inspectors noted that the Unit 1 outage summary reported that repair work was done to remove leak-seal clamps from the flange connections between main feedwater risers No. 1 and No. 32 and the 1B OTSG shell. This item was of interest because the inspectors had learned that these same two flange connections were found to be leaking last January, while the unit was shut down for other reasons, and were leak-sealed again.

During the review of how the licensee was handling the repeat leakage problems on feedwater risers No. 1 and 32, the inspectors questioned whether these failures would be considered a functional failure under the maintenance rule. Discussions with the engineers responsible for administering the maintenance rule program revealed that for the feedwater system, because it is a Class 2 system, the absence of system leakage was not one of the fifteen listed functions monitored by the program. After additional discussions, which included the site Engineering Manager, the licensee decided to generate a PIP form to document the repeat failure for trending purposes, and to question whether system leakage should be a maintenance rule function of the portion of the feedwater system inside the containment.

#### Dominion Engineering, Inc. (DEI) Reports

The inspectors reviewed the following three reports concerning the Oconee OTSGs:

- DEI-483 - Evaluation of Steam Generator Tube Damage Mechanisms
- DEI-484 - Steam Generator Life Prediction Analysis
- DEI-485 - Review of Chemistry and Operating Procedures

These reports, dated February 1997, were provided as an independent analysis of the Oconee 1, 2, and 3 OTSGs. During discussions with licensee engineering, operations, and chemistry personnel, the inspectors learned that as a direct result of recommendations in the DEI reports, the licensee had already implemented changes.

The licensee had revised operations procedure OP/1/A/1106/08, Steam Generator Secondary Hotsoak, Fill, Drain, and Layup, Revision 35, because DEI had concluded that the condition of the secondary water chemistry during startup operations was more critical to the condition of the OTSG tubes than the water chemistry during full-power operations.

The licensee had ordered equipment, and was preparing to modify the feedwater system for the injection of titanium oxide during the next refueling outage for each unit. The addition of titanium oxide is to provide an inhibitor in an attempt to tie up sodium hydroxide (NaOH), especially during startups, to assist in the prevention of additional intergranular attack (IGA) to the outside surface of the OTSG tubing.

#### ABB Combustion Engineering Nuclear Operations (ABB CENO) Reports

The inspectors reviewed the following reports provided to the licensee by ABB CENO concerning tests conducted on three full-length, and two partial-length tubes removed from the 3A OTSG:

- 447-PENG-TR-086, Comparison of Field and Laboratory Eddy Current Testing (ECT) Results, Helium Leak Tests and Observations of Oconee Unit 3 Steam Generator Tube Sections
- 447-PENG-TR-091, Burst Testing of Oconee 3 Steam Generator Tube Sections

The tests reported by ABB CENO were presented in the reports in a clinical fashion; that is, the parameters and results of the tests were presented without final conclusions. The conclusions concerning the tests will be provided upon completion of the metallurgical analyses of the tube sections. This part of the examination is still under way by ABB CENO.

#### c. Conclusions

The condition of the Oconee OTSGs has seen additional licensee attention through BWOG sponsored tube pulls in each unit, and the contract with DEI to do an independent review of the Oconee steam generator program.

The failures of mechanical feedwater piping connections to the Unit 1B steam generator were not being identified or trended as repeat failures.

### M2.3 Repairs of Unit 1 OTSG Tubing

#### a. Inspection Scope (50002)

Through work observation, procedure and records review, the inspector determined the adequacy of OTSG 1B tube repairs in response to eddy

current identified indications in the roll transition area of the upper tube sheet (UTS).

b. Observation and Findings

Background

Eddy current inspection of OTSG 1B tubes was performed during the current outage (EOC-17). This inspection showed that certain tubes exhibited indications at the roll transition region within the UTS and at certain freespan locations. The UTS indications were identified as single or multiple axial or volumetric which typically require roll repair or plugging. In general, the subject indications were characterized as internal diameter intergranular stress corrosion cracks (IGSCC).

The volumetric indications were believed to be the result of intergranular attacks (IGA). In order to investigate these indications further, the licensee selected five tubes with representative indication for investigation. These tube sections were pulled and sent to a laboratory for destructive and non-destructive examinations to determine the failure mechanism. At the time of this inspection, November 3, 1997, the licensee had not received an official report on the subject tubes. At the completion of the eddy current examination the licensee had identified approximately 1936 tubes in OTSG 1B that required repair. This repair involved the re-roll of a one-inch long section of tube below the region where tube defects were identified. The repair established a new mechanical tube-to-tubesheet structural joint and a new primary pressure boundary within the tube.

Observation

Through work observation, document review and discussions with the licensee's cognizant personnel and the vendor's onsite lead engineer, the inspector ascertained the following:

Tube re-roll repairs were being performed by Framatome Technologies, Inc., (FTI). The work was being performed under FTI's QA program and as such FTI was responsible for control of equipment and processes. Representatives of Duke's Supplier Verification Group observed the subject activity and reviewed applicable procedures, equipment calibration records and personnel qualification records for adequacy. The verification group found them to be satisfactory.

During the inspection, as of November 3, 1997, the roll repair activity was still in progress. The inspector observed the repair of selected tubes to verify that the applied torque to achieve the desired tube

expansion did not exceed established procedural limits; that post-roll tube diameter was within established maximum and minimum limits; that equipment was properly calibrated and performing its functions and that personnel were properly qualified. The controlling procedure for the repair was FTI's Document 1246068A, Revision 3 dated June 18, 1997. In addition, the inspector reviewed FTI's two nonconformance reports applicable to this activity. One of these involved a communication problem between the computer and the roll expander tool and the other involved operator error resulting in the inadvertent repair of 13 tubes. Corrective measures taken to prevent recurrence of these problems were considered appropriate.

Following the close of this inspection, the inspector obtained the following information on Oconee's Unit 1 OTSG tube repairs.

#### Tubes Plugged

- 1A 52 tubes were removed from service. Five were located in the lower tubesheet (LTS).
- 1B 122 tubes were removed from service. Five were located in the UTS roll transition area of interest.

#### Tube Pulls

- 1A Five tubes were pulled from LTS. These were scheduled for analysis.
- 1B Five tubes were pulled from UTS and sent for analysis. Two of the three samples with volumetric indications were subjected to nondestructive and destructive examinations.

#### Re-Roll

- 1A 39 tubes were re-rolled in the UTS that will remain in service
- 1B Approximately 1956 tubes were re-rolled in the UTS and will remain in service.

In addition, the inspector determined that the subject repair activity was implemented with relatively good results in that only five re-rolled tubes failed to meet acceptance criteria and were plugged. Also, out of approximately 2000 tubes roll repaired, only 16 were re-rolled inadvertently.

Finally, by letter dated November 18, 1997, from W. R. McCollum, Jr., to the Nuclear Regulatory Commission, the licensee indicated that all roll repaired tubes in the Oconee Unit 1 OTSG B UTS region, have been



classified as Category C-3 as defined in Technical Specifications 4.17.3.d. Therefore all roll repaired tubes will have the new roll area inspected during future inservice inspections.

c. Conclusion

The licensee implemented repairs in OTSG B tubes of Unit 1 in a conservative manner, following administrative controls and applicable controlling procedures. Technical support provided good guidance and oversight during the activity.

### III. Engineering

#### E2 Engineering Support of Facilities and Equipment

##### E2.1 Review of Engineering Backlog

###### a. Inspection Scope (37550)

The inspectors reviewed the engineering support of facilities and equipment as demonstrated by backlogs of engineering work associated with operator workarounds, work orders on engineering hold, PIP reports, nuclear station modifications, minor modifications, and temporary modifications (TMs). Applicable regulatory requirements included 10 CFR 50 Appendix B and the licensee's Quality Assurance program.

###### b. Observations and Findings

The inspectors noted that the overall backlog in engineering had increased during the past year. A significant portion of the increase was in the number of PIPs. The licensee attributed this increase to the Unit 2 pipe rupture event that occurred in September 1996 and the ensuing code compliance work that was performed on all 3 units. The inspectors found that the number of PIPs open for greater than 6 months has declined for the past 3 months to the current level of approximately 315. However, this total was still higher than that in October 1996. The licensee tracks PIPs greater than 6 months old and has established goals to reduce this number to 204 by the end of the year.

The inspectors reviewed the active TMs and found that 12 had been installed for greater than 18 months. Six were installed on Unit 1, which was in a refueling outage. Of those six on Unit 1, five were being closed or removed during this outage. The one remaining item (TM 1188) was to be closed in the next Unit 1 end-of-cycle (1EOC18) refueling outage which was scheduled for March 1999. The licensee indicated that a nuclear station modification was required. Temporary modification number 1188 was installed because the 1D3 reactor building

auxiliary cooling coil was leaking and closing the isolation valves both upstream and downstream of the coil did not fully isolate the leak. The TM installed blind inserts in the LPSW line to isolate the 1D3 reactor building auxiliary cooling coil that was leaking. The inspectors reviewed the IM and associated 10 CFR 50.59 safety evaluation and found them to be acceptable. The licensee indicated that two additional TMs greater than 18 months old were also being closed. This would leave five TMs still open that were greater than 18 months old; however, none of the remaining ones involved safety-related systems.

The inspectors found that the Mechanical Civil Equipment Group (MCE) had a much larger backlog of work orders on hold over 30 days old than those in the other engineering groups. The inspectors discussed this with the licensee and found that MCE considered most of these items to have a lower priority as compared to other work items such as operator workarounds or PIPs. The inspectors discussed the status of most of these items with the supervisors and found that the technical basis for these items having a lower priority appeared to be acceptable.

The inspectors found that the backlog of operator workarounds was up due to 11 new items being added between July and October of this year. The licensee indicated that this increase was a reflection of their ability to better identify from the PIP database those issues that are considered operator workarounds and was not reflective of a lack of engineering response.

The inspectors found that 36 modifications were unscheduled or unslotted. This issue had been identified during the licensee's Modification Selection/Activation Process Performance Assessment SA-97-58 conducted in May 1997. The assessment included a recommendation to management to have the large number of outstanding activated modifications be evaluated by an independent review group to assure that each modification can be justified. The licensee indicated that this review was scheduled for November 1997.

c. Conclusions

Engineering support to operations and maintenance was adequate.

E3 **Engineering Procedures and Documentation**

E3.1 Review of Modifications

a. Inspection Scope (37550)

The inspectors reviewed the modifications to the Unit 1 LPSW system and an unrelated electrical minor modification. The LPSW modifications

review included issues identified by previously identified NRC item IFI 50-269,270,287/96-13-03 related to service water system modification and testing. The following modifications were reviewed:

- NSM-13001/AM1, Install Minimum Flow Piping at LPSW Pumps, dated June 17, 1997
- NSM-13001/AM2, Tie in Minimum Flow Piping to LPSW Pumps, dated August 15, 1997
- NSM-13001/CM1, Installation of Valve 2LPSW-139, dated July 30, 1997
- NSM-13002, Replace 1A, 1B, and 1C LPSW Impellers, dated May 28, 1997
- NSM-13022, Replace Valves 1LPSW-251, -252, -254, and -256, dated August 28, 1997
- NSM-12977, Replace Valves 1LPSW-4, -5, -6, and -15, dated September 11, 1997
- ONOE-10447, Hot Taps for 14-inch and 36-inch LPSW Piping, dated August 19, 1997
- ONOE-11028, Installation of 24-inch Split Tee Fitting on LPSW Piping, dated October 19, 1997
- ONOE-11029, Perform 24-inch Hot Tap and Line Stop on LPSW Piping, dated October 23, 1997
- ONOE-8790, Analog to Digital Conversion of Reactor Protection System (RPS) Channels A,B,C, and D Hardware, dated April 1, 1997

Applicable regulatory requirements included American National Standards Institute (ANSI) N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, 10 CFR 50.59, 10 CFR 50 Appendix B, UFSAR, and the licensee's Quality Assurance (QA) program.

b. Observations and Findings

Design change documentation adequately identified and referenced appropriate design inputs. Post-modification testing was adequate to verify the function of modified equipment. In particular, the modification to install the new pump impellers included adequate flow testing to establish baseline values for Section XI testing. The testing verified that pump capacity was essentially equal to previous capacity and consistent with the vendor pump performance curves. Testing was performed by the vendor to verify that the minimum flow

capacity (500 gallons per minute) provided by the installed recirculation lines was adequate for at least 24 hours of pump operation as required by the recirculation line modification design criteria.

Several minor modifications were implemented to facilitate installation of in-line piping stops (MARBO plugs) for isolation to replace valves or pump changes. Implementing procedures included contingency actions to address potential problems anticipated during the plug replacement and removal. Appropriate seismic analysis was performed to facilitate temporary hardware for plant installation. Field walkdowns demonstrated that seismic supports were consistent with design drawings.

c. Conclusion

Design control for the Unit 1 LPSW modifications was good. The 10 CFR 50.59 evaluations were detailed and thorough.

**E7 Quality Assurance in Engineering Activities**

**E7.1 Review of Engineering Self-Assessments**

a. Inspection Scope (37550)

The inspectors reviewed engineering self-assessment activities that were performed in 1997. Applicable regulatory requirements included 10 CFR 50 Appendix B, and the licensee's QA program.

b. Observations and Findings

The inspectors reviewed 13 self-assessment reports of engineering support and design control activities that were performed in 1997 and found them to be adequate. The assessments resulted in several findings and recommendations being identified. The inspectors found that the reports were clear and concise and that the findings were being tracked by the corrective action program.

c. Conclusions

The engineering self-assessments performed in 1997 were effective in identifying and assuring correction of deficiencies in engineering performance.

**E8 Miscellaneous Engineering Issues (92903)**

**E8.1 (Closed) IFI 50-269,270,287/96-09-03: Expected End-of-Cycle Heat Loads**

This item addressed an apparent inconsistency between the UFSAR and supporting design calculations regarding end-of-cycle SFP heat load

values associated with normal and abnormal SFP loading. The licensee was revising the SFP heat load calculation to address anticipated changes in fuel design and cycle lengths at the time the item was identified. The IFI was identified to track the licensee's verification that the UFSAR specified heat load values for the two conditions bounded the calculated values.

The inspectors reviewed OSC-4998, Units 1 and 2 SFP Heatup Rate Calculation, Revision 7, and UFSAR Sections 9.1.3.1.1 and 9.1.3.3.1, which were revised December 31, 1996, to verify resolution of this item. The calculation determined the bounding heat load conditions for the normal and abnormal SFP loading using fuel burn-up assumptions appropriate to the anticipated core design and cycle length. The normal case heat load was within the previously specified UFSAR value. The abnormal heat load for future anticipated fuel conditions slightly exceeded the previously specified UFSAR value for this case. Both values were within the capacity of the SFP cooling system specified in the UFSAR. The December 31, 1996, UFSAR revision deleted the specific heat load values and core off load descriptions from the UFSAR. The revision additionally clarified that the abnormal case (full core offload) was the routine condition during refueling outages. The inspector concluded this item was adequately resolved.

E8.2 (Closed) LER 50-269/97-03 Revision 0 and 1: Post LOCA Boron Dilution Design Basis Not Met Due to Deficient Design Analysis

(Closed) URI 50-269,270,287/97-01-06: Boron Dilution Flow Path Inoperability

This issue involved the identification of a possible failure of the Post LOCA Boron Dilution flowpaths through LP-1 and LP-2. In Revision 0, the licensee identified through an engineering evaluation of Generic Letter 96-06, that LP-1, LP-2, LP-103, and LP-104 could be inoperable due to thermal over pressurization. This would remove both active boron dilution flow paths from service. Following questioning by the inspectors, the licensee realized they had conservatively neglected the impact of the holes drilled in the upstream disk of LP-1 and the bonnet reliefs on LP-2. These modifications had been made in 1985, 1986, and 1987. Therefore, the active path through LP-1 and LP-2 were operable from the time these modifications were completed to the present. LP-103 and LP-104 were inoperable from initial installation until the recent outages when a void was introduced between the valves. Engineering will perform an evaluation to determine if any other actions are recommended to provide additional margin for LP-1 and LP-2. This evaluation is captured in PIP 0-097-0279; therefore, this LER and URI are closed.

### E8.3 (Closed) URI 50-269,270,287/97-12-02: Fuel Load UFSAR Statements

This URI concerned a discrepancy between the UFSAR and two existing refueling 10 CFR 59.59 evaluations. Specifically, UFSAR Section 4.3.3.1.4 stated in part that "Each fuel rod is identified by an enrichment code, and the design of the reactor is such that only one enrichment is used per assembly." However, the licensee had installed fuel in Unit 2 in 1994 and Unit 3 in 1997 that contained different enrichment (axial blankets) without indicating this discrepancy in their safety evaluations or clarifying the statements in the UFSAR that described one enrichment fuel. This was an oversight, but was not recognized until after the refuelings had occurred. Once recognized in PIP 0-097-0448 (February 3, 1997), it was not addressed in the next UFSAR update issued in July 1997 nor were the 10 CFR 50.59 evaluations changed. PIP 0-097-2511, initiated on August 13, 1997, by an independent site review, brought the matter to a head and an investigation was performed. The 10 CFR 50.59 evaluation for the pending Unit 1 refueling had yet to be completed at the time that PIP 0-097-2511 was initiated. The licensee subsequently completed their evaluation of the problem with the issuance of Root Cause Investigation for PIP 0-097-2511, dated September 23, 1997. The inspectors discussed the problem with the licensee and observed the corrective action scheme.

The investigation revealed that several causes had prevented a proper 10 CFR 50.59 review for a fuel change or the accomplishment of UFSAR updates to reflect actual fuel configurations. The investigation summary root causes were primarily attributed to misjudgement in the level of UFSAR review for the 10 CFR 50.59 evaluation and misjudgement in the level of validation and verification needed to assure corrective action commitments such as a PIP were adequately documented and responsibilities were assigned.

Based on the above, the inspector concluded that the failure to revise the UFSAR to reflect the different fuel enrichments was a violation of 10 CFR 50.71(e). This is identified as VIO 50-270,287/97-15-09: Failure to Update the UFSAR Regarding Fuel Enrichment.

#### IV. Plant Support Areas

##### R1 Radiological Protection and Chemistry Controls

##### R1.1 Tour of Radiological Protected Areas

##### a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program as required by 10 CFR Parts

20.1902, and 1904. The review included observation of radiological protection activities for control of radioactive material, including postings and labeling, and radioactive waste processing.

b. Observations and Findings

At the time of the inspection, Unit 1 was shut down for a scheduled 54 day refueling outage (UIEOC17). The inspectors reviewed survey data of radioactive material storage areas. Observations and survey results determined the licensee was effectively controlling and storing radioactive material and all material observed was appropriately labeled as required by 10 CFR Part 20.1904. The inspectors determined the licensee was processing radioactive waste to maintain exposures As-Low-As-Reasonably-Achievable (ALARA) and to minimize quantities of radioactive waste stored on site.

The inspectors also reviewed and discussed radioactive liquid processing during tours of the radioactive waste (radwaste) facility and observed part of a radioactive liquid discharge in progress. The licensee had recently installed a new radwaste resin sluice system which allowed for the transfer of spent resin from the Units 1, 2, and 3 spent fuel pools, purification and deborating demineralizers to the resin batch tank located in the Radwaste facility. The chief purpose of the modification was to perform radwaste spent resin sluices inside of the facility and not be affected by weather conditions. Another benefit of the modification was that resin sluices could be performed in shorter times, also minimizing personnel radiation exposure.

During tours of the auxiliary building and radioactive waste storage/handling facilities, the inspectors observed the licensee had performed radiological work in 2 onsite buildings, the reactor coolant pump building and the ice blast building, not specified as monitored pathways for radioactive material in the licensee's Offsite Dose Calculation Manual. The inspectors requested additional information regarding the licensee's evaluations of the intended work scope to be performed in the buildings and the associated radiological engineering controls that would be applicable. Pending follow up information to be provided and reviewed, one Unresolved Item (URI) was identified concerning the applicability of monitoring requirements of Criterion 64 of 10 CFR 50 Appendix A and reporting requirements of 40 CFR 190 and 10 CFR 50.36a. This issue will be tracked by URI 50-269,270,287/97-15-03: Determine the Applicability of Monitoring Requirements of Criterion 64 of 10 CFR 50 Appendix A and Reporting Requirements of 40 CFR 190 and 10 CFR 50.36a Regarding Potential of Unmonitored Release Pathways.

c. Conclusions

Based on observations and procedural reviews, the inspectors determined the licensee was effectively maintaining controls for radioactive waste and waste processing. One URI was identified to determine monitoring requirements for radiological work in two onsite buildings. The licensee's initiative to improve resin sluice processing systems to maintain exposures ALARA and to improve environmental controls for resin sluicing was viewed as a strength.

R1.2 Water Chemistry Controls

a. Inspection Scope (84750)

The inspectors reviewed implementation of selected elements of the licensee's water chemistry control program for monitoring primary and secondary water quality as described in the TS limits, the Station Chemistry Manual, and the UFSAR. The review included examination of program guidance and implementing procedures, as well as analytical results for selected chemistry parameters.

b. Observations and Findings

The inspectors reviewed selected analytical results recorded for Units 1, 2 and 3 reactor coolant and secondary samples taken between August 1, 1997, and October 31, 1997. The selected parameters reviewed for primary chemistry included dissolved oxygen, chloride, pH, and fluoride. The selected parameters reviewed for secondary chemistry included hydrazine, iron, and chloride. Those primary parameters reviewed were maintained well within the relevant TS limits for power operations. Those secondary parameters reviewed were maintained according to station procedures. During tours, the inspectors also observed the licensee performing primary system chromate sampling in accordance with licensee procedures. The inspectors observed that the licensee exercised good radiological work practices during the sampling evolution.

c. Conclusions

Based on the above reviews, it was concluded that the licensee's water chemistry control program for monitoring primary and secondary water quality had been effectively implemented, for those parameters reviewed, in accordance with the TS requirements and the Station Chemistry Manual for Pressurized Water Reactor water chemistry.



### R1.3 Transportation of Radioactive Materials

#### a. Inspection Scope (86750, TI 2515/133)

The inspectors evaluated the licensee's transportation of radioactive materials programs for implementing the revised Department of Transportation (DOT) and NRC transportation regulations for shipment of radioactive materials as required by 10 CFR 71.5 and 49 CFR Parts 100 through 177.

#### b. Observations and Findings

The inspectors reviewed and discussed licensee procedures and computer tracking systems and determined that they adequately addressed the following: assuring that the receiver has a license to receive the material being shipped; assigning the form, quantity type, and proper shipping name of the material to be shipped; classifying waste destined for burial; selecting the type of package required; assuring that the radiation and contamination limits are met; and preparing shipping papers.

Licensee's records for three shipments of radioactive material performed since the last inspection of this area were reviewed and the inspectors determined the shipping papers contained the required information. The inspectors also determined the licensee had maintained records of shipments of licensed material for a period of three years after shipment as required by 10 CFR 71.91(a). In addition, the licensee possessed a current certificate of approval (NRC Form 311) for their "Quality Assurance Program Description for Radioactive Material Shipping Packages Licensed Under 10 CFR 71."

#### c. Conclusions

Based on the above reviews, the inspectors determined that the licensee had effectively implemented a program for shipping radioactive materials required by NRC and DOT regulations.

### R2 Status of RP&C Facilities and Equipment

#### R2.1 Meteorological Monitoring Program

##### a. Inspection Scope (84750)

Section 2.3.3.2 of the UFSAR described the operational and surveillance requirements for the meteorological monitoring instrumentation.

b. Observations and Findings

The inspectors toured the control room with cognizant licensee personnel and determined that the meteorological instrumentation was operable and that data for wind speed, wind direction, air temperature, and precipitation were being collected as described in the UFSAR. Records revealed that the licensee had maintained a high level of operability for meteorology equipment during 1997. Wind speed and wind direction at 10 and 60 meters was operable approximately 99.3 percent, air temperature approximately 99.3 percent, and precipitation 99.6 percent.

c. Conclusions

Based on the above reviews and observations, it was concluded that the meteorological instrumentation had been adequately maintained and that the meteorological monitoring program had been effectively implemented.

**R7 Quality Assurance in Radiological Protection and Chemistry Activities**

**R7.1 Quality Assurance in Radiation Protection and Chemistry**

a. Inspection Scope (84750, 86750)

10 CFR 20.1101 requires that the licensee periodically review the radiation protection (RP) program content and implementation at least annually. Licensee periodic reviews of the RP program were reviewed to determine the adequacy of identification and corrective actions.

b. Observations and Findings

The inspectors reviewed the most recent QA audits in the area of RP, chemistry, and transportation. These audits were accomplished by reviewing RP procedures, observing work, reviewing industry documentation, and performing plant walkdowns to include surveillance of work areas by supervisors and technicians during normal work coverage. The inspectors also reviewed documentation of potential radiological problems or areas for improvement through the licensee's PIP.

c. Conclusions

The inspectors determined that the licensee was performing QA audits and effectively assessing the radiation protection program as required by 10 CFR Part 20.1101. The inspectors also determined that the licensee was completing corrective actions in a timely manner.

**R8 Miscellaneous Radiation Protection & Chemistry Issues (92904)****R8.1 (Closed) URI 50-269,270,287/97-01-07: Failure to Meet Requirements of 10 CFR 70.24**

This issue involved the failure to have in place either a criticality monitoring system for storage and handling of new (non-irradiated) fuel or an NRC approved exemption to this requirement contained in 10 CFR 70.24.

10 CFR 70.24 requires that each licensee authorized to possess more than a small amount of special nuclear material (SNM) maintain in each area in which such material is handled, used, or stored a criticality monitoring system which will energize clearly audible alarm signals if accidental criticality occurs. The purpose of 10 CFR 70.24 is to ensure that, if a criticality were to occur during the handling of SNM, personnel would be alerted to that fact and would take appropriate action.

Most nuclear power plant licensees were granted exemptions from 10 CFR 70.24 during the construction of their plants as part of the Part 70 license issued to permit the receipt of the initial core. Generally, these exemptions were not explicitly renewed when the Part 50 operating license was issued, which contained the combined Part 50 and Part 70 authority. In August 1981, the Tennessee Valley Authority (TVA), in the course of reviewing the operating licenses for its Browns Ferry facilities, noted that the exemption to 10 CFR 70.24 that had been granted during the construction phase had not been explicitly granted in the operating license. By letters dated August 11, 1981, and August 31, 1987, TVA requested an exemption from 10 CFR 70.24. On May 11, 1988, NRC informed TVA that "the previously issued exemptions are still in effect even though the specific provisions of the Part 70 licenses were not incorporated into the Part 50 license." Notwithstanding the correspondence with TVA, the NRC has determined that, in cases where a licensee received the exemption as part of the Part 70 license issued during the construction phase, both the Part 70 and Part 50 licenses should be examined to determine the status of the exemption. The NRC view now is that unless a licensee's licensing basis specifies otherwise, an exemption expires with the expiration of the Part 70 license. The NRC intends to amend 10 CFR 70.24 to provide for administrative controls in lieu of criticality monitors.

The NRC has concluded that a violation of 10 CFR 70.24 existed. The NRC has also determined that numerous other licensees have similar circumstances that were caused by confusion regarding the continuation of an exemption to 10 CFR 70.24 originally issued prior to issuance of the Part 50 license. After considering all the factors that resulted in these violations, the NRC has concluded that while a violation did

exist, it is appropriate to exercise enforcement discretion for Violations Involving Special Circumstances in accordance with Section VII B.6 of the "General Statement of Policy and Procedures for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600.

## F1 Conduct of Fire Protection Activities

### F1.1 Licensee Identified Fire Protection Discrepancies

#### a. Inspection Scope (64704)

The inspectors reviewed the adequacy of the licensee's evaluations and corrective actions on the following licensee identified fire protection discrepancies in which PIP reports had been issued.

<u>PIP No.</u>	<u>PIP Description</u>
3-097-1483	Failure to Install Fire Detection in New Unit 3 Computer Room
0-097-1484	High Pressure Service Water (HPSW)/Fire Pump Enclosure Was Not 3-Hour Fire Rated Construction
5-097-2667	Inoperable Fire Door Between Turbine and Auxiliary Buildings
0-097-2806	Fire Protection Valves for Hose Stations Were Not Stroke Tested
1-097-3309	Obstructed Fire Detectors in Unit 1 Reactor Building

#### b. Observations and Findings

The licensee's evaluations on these PIP discrepancies were thorough and corrective action was appropriate. These identified discrepancies demonstrated that the licensee's fire protection staff was performing detail assessments of the site's fire protection program and were taking appropriate action to identify the cause and take corrective action on identified discrepancies. The inspector's observations and findings on each of these PIP items are as follows:

- PIP 3-097-1483: This issue involved the failure to extend the automatic fire detection system to provide coverage for a new computer room in the Unit 3 control room complex. The corrective action for this PIP included the installation of automatic fire detection for the Unit 3 computer room addition. In addition, the modification in process for the Unit 1 and 2 computer rooms was revised to include the installation of automatic fire detectors.

Section 9.5.1.5 of the Oconee UFSAR states that fire detector locations were selected based on engineering judgement to monitor areas containing vital equipment. The computer rooms adjacent to the control rooms were not initially provided with automatic fire detection coverage, but the fire detection system was provided for this area during the upgrades to the plant fire alarm system in the early 1990s. Since the computers were not considered vital equipment, automatic fire detection was not required to be provided for this area during the NRC licensing review. This is documented by the NRC Fire Protection Safety Evaluation Report dated August 11, 1978. The cause for not providing fire detector coverage for this area was identified by the licensee as a design oversight since this area was not initially provided with fire detector coverage. Therefore, although providing fire detector coverage for the computer rooms adjacent to the control room complex is a good fire protection practice, the failure to provide fire detection for these areas is outside the NRC licensing basis for Oconee.

The inspector considered the licensee's identification and correction of this problem as proactive.

- PIP 0-097-1484: During a routine surveillance, the licensee identified that the concrete roof construction of the HPSW/fire pump room enclosure was equivalent to 1-hour fire rated construction whereas the walls for these rooms had a 3-hour fire rating.

Section 9.5.1.5.2 of the Oconee UFSAR states, "The HPSW pumps are located in separate concrete block structures with power cables to the motors being embedded in concrete floor. Separation is by fire rated wall assemblies." The Oconee Fire Protection Safety Evaluation Report dated August 11, 1978, states, "The HPSW pumps are located in the turbine building, each in a small masonry room enclosing the pump and motor... We find the basic water supply system satisfies the provision of Appendix A to Branch Technical Position (BTP) 9.5-1 and is, therefore, acceptable."

The inspector reviewed the Oconee fire barrier drawing series 0-310K and 0-310L and noted that the drawings indicated a 3-hour fire wall enclosure for the pumps, but did not address the fire rating of the roofs/ceilings for the pump enclosures. The licensee's PIP evaluation found the "as built" configuration satisfactory since: (1) HPSW pump rooms would not be exposed to turbulent flame impingement from an oil pool fire; (2) automatic sprinkler systems installed in Turbine Building would cool, dilute and suppress an oil pool fire before the fire reached the pump

rooms; (3) combustible materials were not located on the under side of the pump room ceilings; and (4) heat from oil pool fire which was not completely suppressed by the fire suppression system would dissipate to the open Turbine Building and would not concentrate at the roofs of the HPSW pump rooms.

The inspector performed a walkdown inspection of the Turbine Building and concluded that the licensee's evaluation and the fire protection features provided for the areas were appropriate for the hazards involved and should assure that a fire within the Turbine Building would not damage both HPSW pumps.

The licensee issued PIP 0-097-3920 to add a note on the applicable drawings for drawing series 0-310K and 0-310L to indicate the fire rating of the ceilings/roofs of the HPSW pump rooms had a 1-hour fire resistance rating.

The fire resistance rating of the HPSW pump rooms was not an NRC licensing issue; therefore, this item is not a regulatory issue. The licensee's identification and evaluation for resolution were considered positive actions.

- PIP 5-097-2667: This issue was related to inoperable fire door No. 325 on the 796' elevation of the Auxiliary Building. On August 25, 1997, a member of the licensee's staff found door number 325 with the locking mechanism removed, grey tape was placed over the missing locking mechanism, and a plastic tie wrap was being used for a handle. Operations personnel acknowledged that this door had been in this configuration for at least one day, and possibly longer, and that a work order had not been issued to repair the door. Also, the door had not been declared inoperable and the compensatory actions of UFSAR Section 16, Selected Licensee Commitments (SLC), Item 16.9.5, Fire Barriers, had not been implemented.

Paragraph 3.E of the Oconee Operating License states that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR and as approved in the SERs (i.e., NRC's Fire Protection Safety Evaluation Reports).

For inoperable fire barriers, UFSAR SLC 16.9.5 Action Item a.ii required verification that the area fire detection system was operable and the establishment of an hourly fire watch patrol for the area. Door 325 was located in a high traffic area; therefore, there were many opportunities during the work day for any of the many site employees who passed through this door to recognize that

the door was inoperable and to submit a work order to perform the required repairs.

The failure to promptly identify this inoperable fire barrier penetration and to implement the appropriate compensatory measures of UFSAR SLC 16.9.5 is a violation. However, this non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy and is identified as NCV 50-269,270,287/97-15-04: Inoperable Fire Door With No Compensatory Measures.

- PIP 0-097-2806: During a review of Procedure MP/0/A/1705/032, Fire Hose Stations, which was performed in September 1997, the licensee's reviewer noted that the hose station valves had not been stroke tested as required by the procedure.

The licensee reviewed the completed procedures for MP/0/A/1705/032 from 1992 through 1996 and noted that none of these procedures had stroke tested or cycle tested the valves associated with the fire hose system. All of the hose stations listed by UFSAR SLC 16.9.4 and SLC Table 16.9.4 were flushed and stroke tested on September 12, 1997. This demonstrated that adequate flow was available and the valves and hose stations were operable. All additional fire hose stations installed in facility were satisfactorily flushed and valves were stroke tested on October 24, 1997. Enhancements were made to the procedure to prevent recurrence. The licensee attributed the cause of this event as a human performance error. Personnel assigned the task of performing surveillance tests and inspections on the fire hose system were provided with additional training on the expectations and acceptance criteria for the fire hose system.

Paragraph 3.E of the Oconee Operating License states, "The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR and as approved in the SERs" (i.e., NRC's Fire Protection Safety Evaluation Reports).

UFSAR SLC Section 16.9.4, Surveillance Item a.iii, states, "At least tri-annually, the fire hose station valves shall be partial-stroke tested."

The failure to stroke test the valves for the fire hose station system in accordance with UFSAR SLC 16.9.4 is a violation. However, this non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy and is

identified as NCV 50-269,270,287/97-15-05: Failure to Stroke Test the Fire Hose Station Valves.

PIP 1-097-3309: This issue was related to covering the smoke detector devices in the Unit 1 RB with a plastic material to prevent damage to the detectors during the wash down of the RB while the unit was in a refueling outage. Most of the detectors were only partially covered with the plastic material. These smoke detectors would have been able to perform their intended function. However, on September 18, 1997, two adjacent detectors located on the west side of the second floor of the Unit 1 RB were completely enclosed with the plastic material and would not have performed their intended function. On October 2, 1997, during the performance of fire detection surveillance testing, the testing personnel found these obstructed detectors were not capable of performing their intended function and the RB fire detection system was declared inoperable. The plastic material was removed from these detectors and the system was restored to an operable condition. The licensee determined the cause of this event to be poor program design and work process implementation. The requirement for maintaining the operability of the Reactor Building fire detection systems and the required implementation of compensatory actions for inoperable fire detection systems were discussed with the appropriate personnel.

The inoperable smoke detectors were located in an area which contained electrical cables to components needed to assure reliable decay heat removal and were required to be operable.

Paragraph 3.E of the Oconee Operating License states, "The licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR and as approved in the SERs" (i.e., NRC's Fire Protection Safety Evaluation Reports).

UFSAR SLC Section 16.9.6, Fire Detection Instrumentation, Action Item a states, "When more than 50% of the provided detectors for each equipment/location, or any 2 adjacent detectors for each equipment/location as shown in Table 16.9-6 are not OPERABLE, appropriate action shall be taken consisting of: within 1-hour, a fire watch patrol shall be established to inspect the accessible equipment/location at least once per hour or as permitted by Site Directives." Table 16.9-6 lists the detectors provided for the RB as required to be operable.



The failure to implement the compensatory action requirements for the inoperable fire detection system in the Unit 1 RB in accordance with UFSAR SLC 16.9.6 is a violation. However, this non-repetitive, licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy and is identified as NCV 50-269/97-15-06: Failure to Implement the Compensatory Action Requirements for the Inoperable Fire Detection System in the Unit 1 Reactor Building.

c. Conclusions

The licensee's fire protection staff demonstrated an aggressive attitude in the identification and correction of fire protection deficiencies. However, three Non-Cited Violations were identified for the licensee's failure to meet the fire protection operability requirements for three required fire protection features.

**F2 Status of Fire Protection Facilities and Equipment**

**F2.1 Operability of Fire Protection Facilities and Equipment**

a. Inspection Scope (64704)

The inspectors reviewed the impairment log for fire protection components and features to assess the licensee's performance for returning degraded fire protection components to service. In addition, walkdown inspections were made to assess the material condition of the plant's fire protection systems, equipment, features and fire brigade equipment.

b. Observations and Findings

Operability of Fire Protection Equipment and Components

As of November 6, 1997, there were only five fire protection components listed on the impairment log as degraded. The following items were identified as inoperable: one smoke detector located in the Unit 1 RB, two smoke detectors in the Unit 2 RB, one smoke detector in the Unit 3 RB and the fire hose stations in the Unit 1 RB.

The fire detection systems for the RB were considered operable by UFSAR SLC Section 16.9.6 since more than 50 percent of the detectors were operable and no two adjacent smoke detectors were inoperable. The inoperable smoke detectors were scheduled to be replaced during the next available outage.

For the inoperable Unit 1 RB hose stations, the licensee was maintaining a minimum of four fire extinguishers adjacent to the personnel hatch entrance to the RB from the Auxiliary Building. This met the requirements of UFSAR SLC Section 16.9.4 Action Item b. The hose stations for the Unit 1 RB were inoperable due to modifications in process on the low pressure service during the current refueling outage.

The inspectors reviewed previous impairments listed in the fire protection impairment log and noted that a high priority had been placed on restoring inoperable fire protection features to service. Most of the inoperable features had been restored to service within 24 hours.

The inspectors toured the plant and noted that the material condition of the fire protection systems was good and that the systems were well maintained.

#### Fire Brigade Equipment

The turnout gear for the fire brigade members was stored in lockers adjacent to the two control rooms. Each fire brigade member was assigned his own personal turnout gear, consisting of a coat, pants, boots, gloves, etc. A sufficient number of turnout helmets were provided to equip the fire brigade members expected to respond in the event of a fire or other emergency. This equipment was properly stored and was well maintained.

Additional fire fighting equipment was stored on a motorized fire and rescue vehicle and an equipment trailer stored outside the protected area adjacent to the main administration buildings. An equipment storage trailer and another trailer equipped with foam fire fighting equipment were stored inside the protected area, north of the Radwaste Building. Fire fighting equipment was also stored on carts located on the generator level of the Turbine Building adjacent to Unit 1 and 2 control rooms and Unit 3 control room. Fire hose, nozzles, and miscellaneous fire fighting equipment was stored on the vehicle, trailers and equipment carts. This equipment was properly stored and was well maintained.

#### c. Conclusions

The low number of inoperable or degraded fire protection components, in conjunction with the good material condition of the fire protection components and fire brigade equipment, indicated that appropriate emphasis had been placed on the maintenance and operability of the fire protection equipment and components.

## F2.2 Surveillance of Fire Protection Features and Equipment

### a. Inspection Scope (64704)

The inspectors reviewed the following completed surveillance and test procedures:

- PT/0/A/0250/24, Fire Protection System Three Year Flow Test, Revisions 12 to 15; performed October 14, 1996 and April 3 and 18, 1997.
- PT/0/A/0250/25, High Pressure Service Water and Fire Protection Flow Test, Revision 18; performed May 30, 1997.
- PT/0/A/0250/35, Radwaste Contaminated Oil Tank Skid Areas Sprinkler System Test, Revision 5; performed August 26, 1997.
- PT/1/A/2200/006, Keowee Hydro Unit 1 CO2 Fire Protection System Three Year Flow Test, Revision 8; performed January 15, 1997.
- PT/1/A/2200/006, Keowee Hydro Unit 2 CO2 Fire Protection System Three Year Flow Test, Revision 8; performed June 13, 1996 and July 30, 1996.
- PT/0/A/2200/014, Keowee CO2 System Test, Revision 11; performed May 23, 1997.
- TT/0/A/06201/031, Keowee Fire Pump Performance Verification Test for CIGNA and Flow Meter Verification, Revision 0; performed June 4, 1997.

### b. Observations and Findings

The completed fire protection surveillance tests reviewed by the inspectors had been appropriately completed and met the acceptance criteria. The test procedures were adequate to perform the fire protection surveillance requirements specified by UFSAR Chapter 16.9, SLC.

### c. Conclusions

Adequate surveillance and test procedures were provided for the fire protection systems and features, and implementation of the procedures was effective.

### F2.3 Fire Barrier Penetration Seals

#### a. Inspection Scope (64704)

The inspectors reviewed the installation of the following fire barrier penetration seals to determine if the installed penetration seals met the design documents and were bounded by configurations which satisfactorily passed a fire test which met the requirements of NRC Generic Letter 86-10 and NRC Information Notices, 88-04, 88-56 and 94-28:

<u>PENETRATION NO.</u>	<u>LOCATION</u>	<u>TYPE</u>	<u>SIZE (Inches)</u>
1-M-S-2-A1	Cable Room	Silicone Foam	40x36
1-M-S-8-A1	Cable Room	Silicone Foam	22x68
1-M-S-10-A1	Cable Room	Silicone Foam	1
1-M-F-17-A1	Cable Room	Silicone Foam	18x18
1-N-F-2-A1	Equipment Room	Silicone Foam	26x28
1-N-F-19-A1	Cable Shaft	Silicone Foam	60x96
1-P-E-2-A1	Penetration Room	Silicone Foam	48x48
2-M-F-33-A1	Cable Room	Monocoat	14
2-M-N-3-A1	Cable Room	Silicone Foam	36x48
2-M-W-2-A1	Cable Room	Grout	1
3-P-E-4-A1	Penetration Room	Silicone Foam	41x42

#### b. Observations and Findings

The inspectors inspected each of the above penetrations and reviewed the licensee's design, construction and surveillance inspection records for these penetration seals. The silicone type penetration seals were covered by 1-inch thick ceraform damming boards; therefore, it was difficult to verify the specific design specifications that had been used during the installation of these penetration seals. The design and construction documents permitted several installation seal options to meet the design requirements. The specific requirements were dependent on the barrier construction, thickness of the barrier, and whether the penetration was through a wall or floor fire barrier.

The licensee had begun a project to revalidate the installation of these penetration seals to determine if each penetration was bounded by a

specific design specification that was substantiated by qualified test documents. During this inspection, the licensee initiated PIP 0-097-3922 to expedite the completion of this project. The fire barrier penetration seals for each unit were scheduled to be reevaluated following completion of their next scheduled refueling outage (i.e., early 1998 for Unit 1, Summer 1998 for Unit 2, and Winter 1999 for Unit 3).

The licensee considered the fire barrier penetration seals to be operable based on the previous inspections performed following each refueling outage using Procedure MP/1.2.3/A/1750/018, Fire Protection - Penetration Fire Barrier Inspection, (current Revisions 27, 20, 21 for Units 1, 2, and 3, respectively). These procedures required an inspection of each fire barrier penetration following a unit's refueling outage. In addition, in 1984 the licensee identified a number of discrepancies associated with the facility's fire barrier penetration seals, such as seals improperly installed, cracked, or missing (i.e., actually not installed). Major modification work was required to restore the penetration seals to operable status. Following these modification activities, documentation was apparently not provided to indicate the design specification used for each penetration seal installation.

This issue will be evaluated during a subsequent NRC inspection, upon completion of the licensee's revalidation of the installation of the fire barrier penetration seals. This is identified as Inspector Followup Item (IFI) 50-269.270,287/97-15-07: Review of Licensee's Revalidation of Fire Barrier Penetration Seals.

c. Conclusion

The inspector concluded that the fire barrier penetration seals were functional. However, the licensee had implemented a project to provide sufficient documentation to indicate the seal installations met the design specifications and were bounded by tested configurations.

**F3 Fire Protection Procedures and Documentation**

**F3.1 Fire Fighting Fire Pre-Plans**

a. Inspection Scope (64704)

The inspectors reviewed the following procedures for compliance with the NRC requirements and guidelines:

- Nuclear Station Directive (NSD) 112, Fire Brigade Organization, Training and Responsibilities, Revision 0

- NSD 313, Control of Combustible and Flammable Materials, Revision 0
- NSD 314, Hot Work Authorization, Revision 0
- Oconee Site Directive 3.2.9, Reporting of Fire Protection Impairments, Revision 1/30/96
- Pre-Fire Plans, Oconee Pre-Fire Plans and Procedures

Plant tours were also performed to assess procedure compliance.

b. Observations and Findings

The above procedures were the principal procedures issued to implement the facility's fire protection program. These procedures contained the requirements for program administration, controls over combustibles and ignition sources, fire brigade organization and training, and operability requirements for the fire protection systems and features. The procedures were well written and met the licensee's commitments to the NRC, except for the Pre-Fire Plans. Pre-Fire Plans had not been provided for all plant areas containing safety-related components.

The inspectors performed plant tours and noted that even though the plant was in a refueling outage, implementation of the site's fire prevention program for the control of ignition sources, transient combustibles were good with overall general housekeeping considered satisfactory. Appropriate fire prevention controls were being applied to the accumulation of transient combustible materials, the number of maintenance activities and welding operations in process due to the refueling outage.

During this inspection, the inspector noted that there were a number of areas within the plant which contained or presented a hazard to safety-related components in which the licensee had not developed fire fighting procedures. For example, fire fighting procedures had not been provided for the Unit 3 low pressure injection hatch area on the 771-foot elevation of the Auxiliary Building. This area contained electrical components for the low pressure injection and component cooling systems and presented an exposure fire hazard to the Unit 3 low pressure and high pressure injection pumps.

Paragraph 3.E of the Oconee Operating License states that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR and as approved in the SERs (i.e., NRC's Fire Protection Safety Evaluation Reports).

The licensee's January 6, 1978, fire protection submittal to the NRC stated that "in lieu of fire fighting procedures," general arrangement drawings of all levels within the station and yard areas have been marked showing the location of fire protection equipment and the location of combustibles. These drawings have been located in each control room and in the Safety Supervisor's office. We intend to expand the information on these drawings to indicate additional combustibles, hazards and ventilation systems supplying each location." NRC's August 11, 1978, Fire Protection Safety Evaluation Report, Section C.6.6 found the licensee's proposed actions to provide "the necessary strategies for fighting fires in safety-related areas and areas presenting a hazard to safety related equipment" to be acceptable.

However, the licensee had not provided the necessary strategies for fighting fires in all safety-related areas and areas presenting a hazard to safety-related equipment. This is identified as VIO 50-269,270,287/97-15-08: Fire Fighting Strategies Not Provided for All Safety-Related Areas.

The licensee had previously identified this problem and had developed fire fighting procedures for all safety-related and important plant areas. These procedures had not been issued due to several needed enhancements. PIP 0-097-3921 was issued during this inspection to address this issue and to expedite completing the revisions to these procedures. Revisions to these procedures were scheduled to be completed by June 1998.

c. Conclusions

In general, the fire protection program implementing procedures were well written and met the licensee's commitments to the NRC requirements. Procedure implementation for the control of ignition sources and transient combustibles was good. Overall, general housekeeping was satisfactory. However, a violation was identified involving the failure to provide fire fighting strategies for all plant areas which contained safety-related equipment or presented an exposure hazard to safety-related components.

F5 **Fire Protection Staff Training and Qualification**

F5.1 Fire Brigade

a. Inspection Scope (64704)

The inspectors reviewed the fire brigade organization and training program for compliance with the NRC guidelines and requirements.

b. Observations and Findings

The organization and training requirements for the plant fire brigade were established by NSD 112, Fire Brigade Organization, Training and Responsibilities, Revision 0. The fire brigade for each shift was composed of a fire brigade leader and at least four brigade members from operations and approximately five members from maintenance. The fire brigade leader was a senior reactor operator (SRO) and was normally one of the unit shift supervisors. The other members from operations were non-licensed plant operators. One of the fire brigade members was normally assigned the duties of fire brigade safety officer to provide technical and administrative assistance to the fire brigade leader and to help assure the safe performance of each fire brigade member by checking each member for appropriate dress out prior to entering the fire area, maintaining records of each fire brigade exposure to fire or radiation hazards, use of self-contained breathing apparatus, and reviewing the pre-fire plans during the emergency for assurances that appropriate measures are being followed for compliance with applicable safety and fire hazards in the area. Assignment of a fire brigade safety officer was identified as a program strength.

Each fire brigade member was required to receive initial, quarterly and annual fire fighting related training and to satisfactorily complete an annual medical evaluation and certification for participation in fire brigade fire fighting activities. In addition, each member was required to participate in at least two drills per year. The initial and annual fire fighting training was provided by the fire science department of a local college.

As of the date of this inspection, there was a total of 26 operations trained fire brigade leaders and 73 operations personnel and 32 maintenance personnel on the plant's fire brigade. Approximately five fire brigade leaders, eight operations fire brigade members and five maintenance fire brigade members were assigned to each of the five operations crews. This was a sufficient number to meet the staffing requirements for the plant operations and the facility's fire brigade complement of one team leader and nine members per shift.

The inspectors reviewed the training and medical records for the fire brigade members and verified that the training and medical records were up to date. The facility utilized off-site qualified state certified fire brigade training instructors and a state fire training facility to perform the annual fire brigade training and practical fire training scenarios.

During this inspection, the inspectors witnessed a fire brigade drill on November 4, 1997, involving a simulated fire in an electrical panel located in Room 159, low pressure hatch area on the 771 foot elevation



of the auxiliary building. The response of the fire brigade to the simulated fire was mixed. Shortcomings were identified in the performance of the fire brigade members and the safety officer. After these shortcomings were resolved, the subsequent drill performance was satisfactory. These shortcomings were identified by the licensee, discussed in the post-drill critique, and documented in PIP 0-097-3950 for resolution.

Based upon a review of the licensee's May 1995 QA Triennial Fire Protection Audit, a review of ten previous fire brigade drill summaries, and an NRC resident inspector witnessed drill documented in NRC IR 50-269.270.287/97-12 these shortcomings were not typical or a trend.

c. Conclusions

The fire brigade organization and training met the requirements of the site procedures. The use of the fire brigade safety officer position during fire emergencies was identified as a program strength. Licensee performance during a fire brigade drill conducted during the period was mixed.

**F7 Performance in Fire Protection Activities**

**F7.1 Review of Triennial Fire Protection Audit**

a. Inspection Scope (64704)

The inspector reviewed Triennial Fire Protection Audit, SA-95-24(ON)(RA), which was conducted May 15 through June 8, 1995.

b. Observations and Findings

Audit SA-95-24(ON)(RA) was a triennial QA audit of the facility's fire protection program. The licensee informed the inspector that this was the most recent comprehensive audit of the fire protection program. Duke's December 18, 1991, letter to the NRC stated that performance-based criteria were to be used for establishing audit frequencies at the Duke facilities. NRC's letter dated May 7, 1992, documented that this was satisfactory. Previously, the TS had required annual, biannual and triennial audits of the fire protection program. However, based on the licensee's assessment of good fire protection performance, the most recent audit performed of the Oconee fire protection program was the 1995 triennial audit. As documented in NRC Inspection Report 50-413.414/97-07 for Catawba, the NRC is re-evaluating this issue.

The inspectors reviewed the audit findings from the 1995 QA report and the corrective actions taken on the identified discrepancies. The report indicated that a comprehensive audit had been performed and seven

findings were identified. The inspector reviewed the status of each of these items and verified that the corrective action on each finding had been completed.

c. Conclusions

The 1995 audit and assessment of the facility's fire protection program were comprehensive and appropriate corrective action was promptly taken to resolve identified issues.

V. Management Meetings

**XI Exit Meeting Summary**

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 18, 1997. The licensee acknowledged the findings presented. Dissenting comments were received from the licensee and resolved by the NRC. Proprietary information is not contained in this report.

**Partial List of Persons Contacted**

Licensee

D. Brandes, Consultant Engineer, Nuclear Engineering  
 E. Burchfield, Regulatory Compliance Manager  
 T. Coutu, Scheduling Manager  
 D. Coyle, Mechanical Systems Engineering Manager  
 T. Curtis, Operations Superintendent  
 B. Dobson, Mechanical/Civil Engineering Manager  
 W. Foster, Safety Assurance Manager  
 D. Hubbard, Maintenance Superintendent  
 C. Little, Electrical Systems/Equipment Engineering Manager  
 W. McCollum, Vice President, Oconee Site  
 M. Nazar, Manager of Engineering  
 B. Peele, Station Manager  
 J. Smith, Regulatory Compliance

NRC

D. LaBarge, Project Manager

**Inspection Procedures Used**

IP37550      Engineering  
 IP37551      Onsite Engineering  
 IP37828      Installation and Testing of Modifications

IP40500 Effectiveness of Licensee Controls In Identifying and Preventing Problems

IP50002 Steam Generators

IP61726 Surveillance Observations

IP62700 Maintenance Program Implementation

IP62707 Maintenance Observations

IP64704 Fire Protection Program

IP71707 Plant Operations

IP71714 Cold Weather Preparations

IP71750 Plant Support Activities

IP84750 Radioactive Waste Treatment, and Effluent and Environmental Monitoring

IP84760 Solid Radioactive Waste Management and Transportation of Radioactive Material

IP92903 Followup - Engineering

IP92904 Followup - Plant Support

Items Opened, Closed, and Discussed

Opened

- 50-269,287/97-15-01 VIO Failure to Complete Required Technical Specification Surveillances on LPI Flow Instruments (Section M1.5)
- 50-269,270,287/97-15-02 URI Valve Parts Identification Problem (Section M2.1)
- 50-269,270,287/97-15-03 URI Determine the Applicability of Monitoring Requirements of Criterion 64 of 10 CFR 50 Appendix A and Reporting Requirements of 40 CFR 190 and 10 CFR 50.36a Regarding Potential of Unmonitored Release Pathways (Section R1.1)
- 50-269,270,287/97-15-04 NCV Inoperable Fire Door With No Compensatory Measures (Section F1.1)
- 50-269,270,287/97-15-05 NCV Failure to Stroke Test the Fire Hose Station Valves (Section F1.1)
- 50-269/97-15-06 NCV Failure to Implement the Compensatory Action Requirements for the Inoperable Fire Detection System in the Unit 1 Reactor Building (Section F1.1)
- 50-269,270,287/97-15-07 IFI Review of Licensee's Revalidation of Fire Barrier Penetration Seals (Section F2.3)
- 50-269,270,287/97-15-08 VIO Fire Fighting Strategies Not Provided for All Safety-Related Areas (Section F3.1)
- 50-270,287/97-15-09 VIO Failure to Update the UFSAR Regarding Fuel Enrichment (Section E8.3)

Closed

- 50-269,270,287/96-09-03 IFI Expected End-of-Cycle Heat Loads (Section E8.1)
- 50-269/97-03, Revs. 0 and 1 LER Post LOCA Boron Dilution Design Basis Not Met Due To Deficient Design Analysis (Section E8.2)

50-269.270.287/97-01-07      URI    Failure to Meet Requirements of 10 CFR  
70.24 (Section R8.1)

50-269.270.287/97-12-02      URI    Fuel Load UFSAR Statements (Section E8.3)

50-269.270.287/97-01-06      URI    Boron Dilution Flow Path Inoperability  
(Section E8.2)

Discussed

50-269.270.287/96-13-03      IFI    Service Water Modifications (Section E3.1)

### List of Acronyms

ABB	Asea Brown Boveri
ALARA	As Low As Reasonably Achievable
ANSI	American National Standard
ASME	American Society of Mechanical Engineers
BTP	Branch Technical Position
BWOG	Babcock and Wilcox Owners Group
BWST	Borated Water Storage Tank
CENO	Combustion Engineering Nuclear Operations
CFR	Code of Federal Regulations
CCW	Condenser Circulating Water
DC	Direct Current
DEI	Dominion Engineering, Incorporated
DOT	Department of Transportation
ECT	Eddy Current Testing
EPSL	Emergency Power Safeguards Logic
EWST	Elevated Water Storage Tank
FIP	Failure Investigation Process
FIT	Framatome Technologies, Inc.
GPM	Gallons Per Minute
HPSW	High Pressure Service Water
ICCM	Inadequate Core Cooling Monitor
IFI	Inspector Follow-up Item
IGA	Intergranular Attack
IR	Inspection Report
KV	kilovolt
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MFB	Main Feeder Busses
MCE	Mechanical Civil Equipment Group
MP	Maintenance Procedure
NC	North Carolina

NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NRC	Nuclear Regulatory Commission
NSD	Nuclear System Directive
OAC	Operator Aid Computer
OTSG	Once-Through-Steam-Generator
PDR	Public Document Room
PIP	Problem Investigation Process
PT	Performance Test
PWR	Pressurized Water Reactor
QA	Quality Assurance
QC	Quality Control
RB	Reactor Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REV	Revision
RP	Radiation Protection
SALP	Systematic Assessment of Licensee Performance
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SG	Steam Generator
SLC	Selected Licensee Commitment
SNM	Special Nuclear Material
SRO	Senior Reactor Operator
SSF	Safe Shutdown Facility
TDEFWP	Turbine Driven Emergency Feedwater Pump
TM	Temporary Modification
TS	Technical Specification
TT	Temporary Test
TVA	Tennessee Valley Authority
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UTS	Upper Tube Sheet
V	Volt
VA	Virginia
VIO	Violation
WO	Work Order