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Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7812B Rochester Highway Seneca, SC 29672
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/98-06,
50-270/98-06, and 50-287/98-06

This integrated inspection included aspects of licensee operations, maintenance, engineering, and plant support. The report covers a six-week period of resident inspection, as well as the results of announced inspections by three region based inspectors. [Applicable template codes and the assessment for items inspected are provided below.]

Operations

- The Unit 2 reduced inventory operation was completed properly with deliberate operator action, good supervisory oversight, and good procedure adherence. (Section O1.2, [1A, 3A, 3C - Good])

- The overall Unit 2 startup was performed by control room personnel with good command and control, control room communications, shift turnover activities, and use of appropriate procedures. (Section O1.3, [1A, 3A - Good])

- The control of personnel access to the main control panel areas was good. Access to the control room was restricted. The inspectors observed that discussions involving equipment status were generally conducted outside the main control panel areas. This resulted in minimal interference with the operating unit and the startup activities (**Human Performance under the Recovery Plan**). (Section O1.3, [1A - Good])

- During the Unit 2 outage, the inspectors observed some delays and some minor examples of poor communications. Those were fewer than those seen during the preceding lengthy Unit 1 outage (**Human Performance under the Recovery Plan**). (Section O1.3, [3A - Adequate])

- During the outage and through the Unit 2 startup, the licensee tracked and discussed outage problems. This process culminated in a post-outage meeting to critique outage problems and provide positive direction to the outage process (**Human Performance under the Recovery Plan**). (Section O1.3, [3B - Good])

- The lack of a procedure to adjust reactor coolant pump restraints was a violation of the licensee's Technical Specifications (Section O1.4, [2B - Poor])

- Operations response to the engineer's phone call regarding the reactor coolant pump shaft rubbing problem was prompt, showing good communications and plant understanding. (Section O1.4, [1B - Good])

- The surveillance procedure used to determine operability of the Unit 2 and 3 reactor coolant makeup pumps was found to be using the wrong reactor coolant pump seal return flow instrument for determining total reactor coolant system leakage. This item was left unresolved pending NRC review of the licensee's past operability determination. (Section

01.5 [2B - Poor])

- Plant systems responded appropriately following a Unit 2 reactor trip with only minor problems noted. (Section 01.6, [1B, 5A - Adequate])

- Reactor building tours conducted at hot shutdown prior to Unit 2 startup were thorough and detailed. This indicates corrective actions dealing with material conditions in the reactor building have been effective in upgrading housekeeping (**Material Condition under the Recovery Plan**). (Section 02.1, [2A, 2B, 3A - Good])

- Items found during Unit 2 reactor building tours at hot shutdown were properly dispositioned in the licensee's work management system, however, there was room for improvement in the procedure documentation of the resolution (**Human Performance under the Recovery Plan**). (Section 02.1, [2B - Adequate])

- Licensee response to a degraded grid was prompt and complete. Operators responded well and technical followup on the encountered problems was also prompt and continuing after the end of the inspection period. (Section 02.2, [1B - Good])

- During the period, there was a mispositioning of Valve 2HP-116 that requires further licensee analysis. The residents identified an unresolved item to track those issues. (Section 02.3, [3B, 4B, 5A - Poor])

- The licensee identified a mispositioned valve that may affect the penetration room ventilation system. This item was left unresolved pending completion of the licensee's investigation and further NRC review. (Section 02.4, [1A, 3A - Poor])

- As a corrective action resolution, the licensee positively implemented temporary defenses for continuous management oversight during Unit 2 startup and for periodic monitoring of Unit 2 reactor coolant system inventory (**Temporary Defense under the Recovery Plan - closed**). (Section 04.1, [1A, 5C - Good])

- Lack of attention to detail resulted in a violation of procedure requirements and the inadvertent starting of an engineered safeguards component. (Section 04.2, [1A, 3A, 3B - Poor])

- The failure to properly implement surveillance requirements at the times specified in the Technical Specifications resulted in a non-cited violation. (Section 08.1, [2B - Poor])

- The identification of discrepancies in the frequencies for refueling outage surveillance requirements was acceptable. (Section 08.1, [5A, 5C - Adequate])

- When it was determined that potential degraded fire protection existed, the licensee properly and promptly established compensatory action,

i.e., fire watches were initiated in accordance with commitments. (Section F2.1, [2A - Good])

- The licensee was timely in recognizing the fire protection issue and made an appropriate notification to the NRC. (Section F2.1, [5C - Good])

Maintenance

- Unit 2 tripped due to loss of vacuum. The licensee was still investigating the maintenance and configuration control problems that caused the trip with a Licensee Event Report to follow. (Section O1.6, [1A, 1C, 3A - Poor])

- The revision of the control rod drive thermal barrier procedure by maintenance to complete additional inspections was seen as a positive. Subsequent testing of the repaired control rod drive mechanisms did not indicate any problems **(Recovery Plan)**. (Section M1.2, [2B, 3C - Good])

- Engineering support of the control rod drive mechanism (CRDM) changeout and evaluation of the control rod drive mechanisms was seen as a positive **(Recovery Plan)**. (Section M1.2, [4B - Good])

- The use of operating experience feedback in the inspection of the CRDM motor tube welds was seen as a positive **(Self-Assessment under the Recovery Plan)**. (Section M1.2, [5B - Good])

- The inspectors identified an unresolved item with the failure of and maintenance on the Unit 1 and 2 low pressure service water pumps. (Section M2.1, [2A, 2B - Poor])

- The inspectors identified a violation for failure to issue a maintenance procedure to clean the system strainers following installation of the Unit 2 siphon seal water system. This failure resulted from a weakness in the process for implementing procedure changes following plant modifications. (Section M3.1, [2B - Poor])

- Corrective actions were found to be good for two violations which involved: (1)a failure to perform procedure prerequisites when draining the elevated water storage tank; and (2) a failure to provide adequate corrective actions for both an eroded high pressure mini-flow injection orifice and an inadequate weld on an orifice assembly **(Recovery Plan)**. (Sections M8.1 and M8.2, [5B, 5C - Good])

Engineering

- The early identification of a reactor coolant pump problem made by a touring engineer was positive in preventing the condition from worsening. (Section O1.4, [3A, 3B, 5A - Excellent])

- The failure to have a procedure to adjust the reactor coolant pump restraints indicated a lack of evaluation and understanding of plant

operation. This was identified as a violation of the licensee Technical Specifications. (Section O1.4, [1B, 5B - Poor])

- Engineering resolution of a minor problem with the essential siphon vacuum system was good. Testing met acceptance criteria. (Section E1.1, [4A, 3B, 5B - Good])

- The inspectors concluded that the failure investigation for the incore power tilt produced adequate conclusions and findings and that the recommendations were technically sound. (Section E2.1, [5B - Adequate])

- During the Unit 2 outage the licensee adequately completed reactor coolant pump impeller work and inspections as necessary to reliably operate for the next fuel cycle **(Operational Concerns under the Recovery Plan)**. (Section E2.2, [3B, 1C - Adequate])

- The licensee effectively planned and managed work on the Unit 2 reactor coolant pumps and activities surrounding the pumps and associated activities. (Section E2.2, [5C - Good])

- The inspectors identified a violation for failure to follow the procedure for safety evaluations performed under Title 10 Code of Federal Regulations Part 50.59 when changing the core operating limits report. (Section E3.1, [4B - Poor])

- Prior to the Unit 2 restart, the licensee completed all necessary problem report corrective actions. The 35 reviewed problem reports were technically sound and used good engineering judgement. **(Recovery Plan under Corrective Action)**. (Section E7.1, [4B - Good])

- The self initiated technical audit of the high pressure injection and low pressure injection systems and interconnecting systems was a thorough and detailed effort that was effective in identifying equipment and programmatic issues **(Recovery Plan under Corrective Action)**. (Section E7.2, [5A - Excellent])

- The licensee's documented evaluations were weak for some of the problem investigation process reports associated with findings from the self initiated technical audit of the high pressure injection and low pressure systems. Some of the reports were characterized by problem evaluations with indeterminate causes, poor supporting documentation of conclusions, and screening of the issues as low significance based on engineering judgement, which prevented operability determinations from being performed **(Recovery Plan under Corrective Action)**. (Section E7.2, [5B - Poor])

- The licensee's actions to resolve a previously identified weakness regarding the review of less significant event problem investigation process reports for generic applicability was noted as a positive observation **(Recovery Plan under Corrective Action)**. (Section E7.2, [5C - Good])

- Overall, the inspectors concluded the program used for post modification testing of the new integrated control system on Unit 2 was thorough and complete. The implementation of that program was well controlled with good evaluation of results. (Section E8.1, [2B - Excellent])

- The licensee discovered information about steam generator tube inspection activities from an outside source. The licensee factored this emergent operational data into their on-going Unit 2 generator inspection **(Self-Assessment under the Recovery Plan)**. (Section X2, [5A, 5B - Good])

- The evaluation of the operational data on Unit 2 steam generator tube inspections revealed a weakness in the licensee inspection program. (Section X2, [4B, 4C - Poor])

- The immediate evaluation of the steam generator tube end anomaly problem revealed there was no safety impact. Subsequent more thorough review of actual tube inspection data on Units 1 and 3 based on updated inspection criteria, revealed that Surveillance Requirement 4.17.2 had not been completed. (Section X2, [5B - Adequate])

- A notice of enforcement discretion was issued to allow continued operation of Units 1 and 3 until an appropriate Technical Specification amendment is approved. An unresolved item was identified to followup collateral issues around the discretion. (Section X2, [5C - Poor])

- The request for notice of enforcement discretion on the steam generator tube indication problem and the submitted Technical Specification change request were technically complete. (Section X2, [4B - Adequate])

- Previously identified apparent violation EEI 50-269,270/98-03-04 (Unresolved Safety Question Involving Single Failure Vulnerability Introduced by a 1984 Control Room Ventilation System Modification) was dispositioned by letter dated June 5, 1998, as a severity level IV violation. (Section X3, [4B - Poor])

- Previously identified apparent violation EEI 50-269,270/98-03-05 (Untimely Final Safety Analysis Report Change for 1984 Control Room Ventilation System Modification) was dispositioned by letter dated June 5, 1998, as a non-cited violation. (Section X3, [4A - Poor]; [5A - Adequate])

Plant Support

- The inspectors concluded that sample requirements for the out-of-service LPSW system radiation monitor were performed adequately. (Section R1.1 [1C; 3A, 3B - Adequate])

- The inspectors identified a violation for a worker exiting a contaminated area without properly removing protective clothing. This violation appeared to be caused by inadequate knowledge of protective clothing requirements on the part of the worker. (Section R4.1, [3B - Poor])

- The alarm stations were appropriately equipped and operating in an excellent manner. (Section S1, [2A - Excellent])
- The security communication equipment was operating properly and the required communication tests were being conducted. (Section S1, [1C, 2A - Good])
- The protected area access controls for packages, personnel and vehicles were implemented in an excellent manner and according to the physical security plan. (Section S1, [1C - Excellent])
- The excellent testing program and maintenance support provided to the security program was a major factor to the continued operability of the detection and assessment equipment. (Section S2, [1C - Excellent])
- The licensee used good compensatory measures that ensured the reliability of security related equipment and devices. (Section S2, [1B - Good])
- The protected area assessment aids had good picture quality and excellent zone overlap. (Section S2, [2A - Excellent])
- The protected area detection aids were functional and effective, and more than met the requirements of the physical security plan. (Section S2, [2A - Good])
- The licensee's security procedures were thorough and well documented concerning the physical security plan. (Section S3, [3C - Good])
- The licensee's safeguards event logging/reportability program properly analyzed, tracked, resolved and documented security incidences. (Section S3, [3C - Good])
- During 1998 there were two incidents of fire due to electrical equipment failures within safe-shutdown significant areas. In both cases, licensee personnel identified and extinguished the fire condition in a timely manner, contained the fire to the original source, and prevented the fire from spreading to other equipment or cables. (Section F1.1, [3B - Good])
- A violation of procedural requirements was identified for not using and correctly storing transient combustibles in safety-related areas. The observed material condition in the plant indicated that the various plant departments were not consistently implementing their responsibilities for combustible material control. (Section F1.2, [2A - Poor])
- The observed level of plant housekeeping did not reflect good prganization and cleanliness practices on the part of plant workers. (Section F1.2, [3A - Poor])

- The general material condition of the fire pumps and the fire protection water supply was good **(Material Condition under the Recovery Plan)**. (Section F2.2, [2A - Good])

- The physical separation of the redundant high pressure service water fire pumps was well maintained and met the criteria described in the updated final safety analysis. (Section F2.2, [4A - Adequate])

- Sufficient procedural guidance was provided to verify that the reactor coolant pump oil collection tanks were normally maintained empty and that the plant operators could identify an oil leak from the lubrication system of any one of the reactor coolant pump motors and take appropriate action. The reactor coolant pump oil collection system met the performance criteria of 10 CFR 50 Appendix R Section III.O. (Section F2.3, [2A - Good])

- The low number of inoperable or degraded fire protection components indicated that appropriate emphasis had been placed on the maintenance and operability of the fire protection equipment and components. Impaired fire protection components had been restored to service in a timely manner. (Section F2.4, [3A - Good])

- The scope and content of the maintenance inspection and surveillance test program procedures for the fire protection hose stations and standpipes were sufficient to assure that the fire protection design and surveillance requirements specified in the updated final safety analysis report were met. (Section F3.1, [1C - Adequate])

- The fire brigade organization and drill program met the requirements of the site procedures. The performance by the fire brigade as documented by the licensee's drill evaluations was good. (Section F5.1, [4C - Adequate])

- An unresolved item was identified regarding the licensee's installation, maintenance, repair, and inspection of penetration seals. (Section F7.1, [2A - Poor])

- The 1998 Triennial Fire Protection Audit of the facility's fire protection program was comprehensive and effective in identifying fire protection program performance to plant management **(Corrective Action under the Recovery Plan)**. (Section F7.1, [5A - Excellent])

Report Details

Summary of Plant Status

Unit 1 began the period at 100 percent power. On May 21, 1998, power was reduced to 60 percent for work on the 1B main feedwater pump. The unit was restored to 100 percent power on May 22, 1998, and remained there throughout the inspection period.

Unit 2 began the period in a scheduled refueling outage. The unit was taken critical on May 22, 1998, and connected to the grid on May 25, 1998. Unit 2 tripped from 80 percent power on June 3, 1998, due to loss of vacuum. The unit was restarted on June 6, 1998, reached 100 percent power on June 7, 1998, and remained there for the rest of the inspection 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. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and parameters.

I. Operations

O1 Conduct of Operations

O1.1 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.

O1.2 Unit 2 Drain for Nozzle Dam Removal

a. Inspection Scope (71707)

On May 3, 1998, the licensee drained the Unit 2 reactor coolant system (RCS) to mid-loop conditions to remove nozzle dams following completion of once through steam generator (SG) tube repairs. The inspectors observed reduced inventory activities.

b. Observations and Findings

The licensee entered reduced inventory operations when the operators reduced the RCS level to less than 50 inches above the centerline of the hot legs. The inspectors were present in the control room and observed draining operations until the RCS level stabilized at 19 inches above the centerline of the hot legs. The inspectors observed that licensee controls of electrical power, containment closure, RCS level indication, exit thermocouples, RCS makeup capability, and RCS vent path met licensee procedural requirements.

The inspectors also observed the operators routinely referring to their procedure and careful oversight by both senior reactor operators and licensee management.

c. Conclusions

The Unit 2 reduced inventory operation was completed properly with deliberate operator action, good supervisory oversight, and good procedure adherence.

01.3 Outage and Startup Activities Following Refueling - Unit 2

a. Inspection Scope (71707)

The inspectors periodically observed control room activities in the Unit 1 and 2 control rooms during the Unit 2 startup from May 13 through May 26, 1998. Among the observations were post-outage equipment testing, equipment operation, command and control, and shift turnovers. The observations were discussed with the licensee.

b. Observations and Findings

The inspectors observed the use of procedures by the operators, command and control by supervisors and managers, control room operator communications, and shift turnover activities. During the outage, licensee management raised expectations for conduct of operations. Licensee management indicated that communication within the control rooms was to be more formalized and controlled. While equipment problems were observed, most were much less severe than those experienced in the Unit 1 outage that ended in February 1998. From direct observation, the inspectors concluded that the overall Unit 2 startup was performed by control room personnel with good command and control, control room communications, shift turnover activities, and use of appropriate procedures.

The control of personnel access to the main control panel areas was good. Under new management instructions, access to the control room was severely restricted over what it had previously been. The inspectors observed that discussions involving equipment status were generally conducted outside the main control panel areas. This resulted in minimal interference with the operating unit and the startup activities.

During the Unit 2 outage, work delays were observed. The licensee documented these in problem identification process reports (PIPs). The inspectors reviewed these PIPs and discussed them with licensee management as appropriate. Further, the licensee discussed these problems during various outage meetings, using that forum as an instructional opportunity.

The inspectors found that some of the delays were due to equipment problems and some were due to poor communications between and within various organizations. During the last Unit 1 outage ending in February, the licensee experienced extensive delays and a high number of

equipment failures that resulted in an extended refueling and forced outage. The Unit 2 outage had fewer equipment problems and fewer delays. After the Unit 2 outage, the licensee held a critique on outage problems and delays. From a human performance measure, this was an extensive meeting involving upper management and all major department heads (and their immediate reports). This meeting attempted to systematically address the problems and provide future improvements in outage process. An outage report was to be issued after the end of the inspection period. The lessons learned were to be applied to future outages.

c. Conclusions

The overall Unit 2 startup was performed by control room personnel with good command and control, control room communications, shift turnover activities, and use of appropriate procedures.

The control of personnel access to the main control panel areas was good. Access to the control room was restricted. The inspectors observed that discussions involving equipment status were generally conducted outside the main control panel areas. This resulted in minimal interference with the operating unit and the startup activities.

During the Unit 2 outage, the inspectors observed some delays and some minor examples of poor communications. Those were fewer than those seen during the preceding lengthy Unit 1 outage.

During the outage and through the Unit 2 startup, the licensee tracked and discussed outage problems. This process culminated in a post-outage meeting to critique outage problems and provide positive direction to the outage process.

O1.4 Unit 2 Reactor Coolant Pump (RCP) Restraint Problem

a. Inspection Scope (71707, 37551, 62707)

In the early evening of May 18, 1998, Unit 2 operations personnel were notified that the 2A1 RCP was emitting sparks and rubbing noise in the vicinity of the pump/motor coupling area. The inspectors observed the pump conditions, talked with the licensee, and reviewed technical data on the pump condition.

b. Observations and Findings

A licensee engineer was inspecting the Unit 2 reactor building (RB), observing general piping vibration levels during plant heat up. The plant was being heated up for return to power operations after a refueling outage. The 2A1 RCP had been running for some period and then was shutdown for the repair of a minor oil leak on the motor. Prior to the shutdown at about 350 degrees F, the inspectors observed that the pump vibration levels and operating parameters were acceptable. The RCP was returned to service about 6:00 p.m. on May 18, 1998. At approximately 7:20 p.m., with the plant at about 1700 pounds per square

inch gauge (psig) and 520 degrees F, the engineer in the RB heard an unusual noise and saw sparks coming from the RCP. He called the control room and the 2A1 RCP was secured. A failure investigation process (FIP) team and PIP 2-098-2679 were initiated.

There are two loss of coolant accident (LOCA) restraints on each RCP which are provided to prevent excessive pump motion during a LOCA condition. The restraints are normally loose (i.e., the pinned connections to RCP motor and an adjacent concrete wall are slotted such that thermal growth can occur). In the case of the 2A1 and the 2B1 RCPs, the restraints were misadjusted such that one restraint on each pump was under tension. The tension on the 2A1 RCP was high enough that the motor stand and motor were deflected toward the wall, causing the motor shaft to rub on a cover over the pump seal package that produced heat and sparks without fire.

To relieve the stress on the tensioned restraint, the licensee cooled the plant to about 350 degrees F on the evening of May 20, 1998. This action reversed the thermal growth of the RCS piping, thereby, allowing piping contraction and tension removal from the restraint. The restraints on all RCPs were inspected and recentered. On restart, the 2A1 RCP vibration levels and other parameters were observed and found to be acceptable.

Since construction, there has not been a procedure for adjustment of the RCP LOCA restraints. This condition is a violation of Technical Specification (TS) 6.4.1.e in that a procedure important to safe operation of the RCPs was not available. This is identified as Violation (VIO) 50-269,270,287/98-06-01: Lack of Procedure for Adjusting RCP Restraints.

The PIP assessment supported the fact that the rubbed cover was satisfactory for continued operation and that the rubbing had not diminished any safety margin. Further, the RCP seal package was not damaged by the bending moment applied by the restraint stress. The failure investigation had not completed its final report by the end of the inspection period.

The FIP interim report (PIP 0-098-2679) evaluated the restraint condition on operating Units 1 and 3 RCPs. Based on satisfactory operational performance data, the pumps were considered operable. Restraint inspections were slated to be performed at the next hot shutdowns for these units. The inspectors reviewed the pump data and agreed with the licensee's conclusion.

c. Conclusions

The early identification of a reactor coolant pump problem made by a touring engineer was positive in preventing the condition from worsening.

The lack of a procedure to adjust the reactor coolant pump restraints was a violation of the Technical Specifications.

Operations' response to the engineer's phone call regarding the rubbing problem was prompt, showing good communications and plant understanding.

O1.5 Reactor Coolant Pump 2A1 Upper Seal Cavity Pressure

a. Inspection Scope (71707)

On May 20, 1998, while observing startup activities, the inspectors noted that the upper cavity seal pressure for RCP 2A1 was indicating lower than the remaining three pumps. The inspectors brought this to the attention of operations shift personnel and discussed it with appropriate operations, engineering, and maintenance personnel.

b. Observations and Findings

The upper seal cavity pressure for RCP 2A1 was indicating 340 psig, while the same indication for the other three pumps were all between 720 psig and 780 psig. RCP 2A1 was not running at the time. Unit 2 RCS pressure was 2150 psig. On May 21, 1998, with RCP 2A1 in operation and RCS pressure at 1400 psig and increasing, the upper seal cavity pressure for RCP was indicating 300 psig while the same indication for the other three pumps was between 450 psig and 500 psig. On the same two days, the lower seal cavity pressures for all four pumps indicated within 100 psig of each other.

In normal operation, upper seal cavity pressure would have been approximately one third of RCS pressure with the lower seal cavity pressure about two thirds of RCS pressure. This is because each Unit 2 RCP contains three seals each of which drops one third of the RCS pressure.

Licensee instrument personnel checked the instrument string and found it to be working properly. They also attempted to measure cavity pressure directly at the instrument root valve and found it to match what the chart recorder was indicating for RCP 2A1 upper seal cavity pressure. In the process of troubleshooting, the indicated upper seal cavity pressure for RCP 2A1 dropped to less than 50 psig. The licensee determined that the seals for RCP 2A1 were functioning properly but the instrument line was most likely blocked upstream of the root valve and could not be corrected without cooling and draining the RCS. The licensee provided operations guidance on how to determine seal performance with the upper seal cavity pressure indication not available.

The inspectors determined that RCP 2A1 upper cavity seal pressure indication was not working properly on May 20, 1998, even though RCP 2A1 was not running at the time. The inspectors also agreed with the licensee that the seals for RCP 2A1 were functioning properly but the upper seal cavity pressure instrument was not sensing the actual pressure in the cavity. The licensee indicated that whatever was preventing the instrument line from sensing the true pressure would be corrected at the next outage that required cooling and draining the RCS.

The licensee later discovered that Procedure PT/2/A/0600/010, RCS Leakage, Revision 15, Enclosure 13.4 for determining operability of the reactor coolant (RC) makeup pump could not be completed. This was because the enclosure relied on seal return flow calculated using the RCP 2A1 upper seal cavity pressure. They further determined that the engineering limit for total RCS leakage for RC makeup pump operability was based on flow signals from flow instruments in the seal return line and not the calculated flows from upper seal cavity pressure. The licensee initiated PIP Form 0-098-2765, changed procedures PT/2&3/A/0600/010, and performed an operability evaluation for the Unit 2 and 3 RC makeup pumps. This evaluation showed the pumps to be operable, but that further evaluation was needed for past operability. The Unit 1 RC makeup pump was not affected because Unit 1 contained a different make of RCPs.

The inspectors reviewed the PIP, the TS, and the design basis document for RC makeup pump operability. For the RC makeup pump(s) to remain operable, RCS leakage plus seal return flow from all RCPs must be within the capacity of the RC makeup pump(s). The inspectors determined that using calculated seal return flow based on upper cavity seal pressure instead of actual seal return flow could affect the validity of data obtained in procedures PT/2&3/A/0600/010. The validity of previous data will be confirmed when the licensee completes the evaluation for past operability. This item will be tracked as Unresolved Item (URI) 50-270,287/98-06-03: Unit 2 and 3 RC Makeup Pump Past Operability, pending licensee evaluation of past operability for the Unit 2 and 3 RC makeup pumps.

c. Conclusions

The surveillance procedure used to determine operability of the Unit 2 and 3 reactor coolant makeup pumps was found to be using the wrong reactor coolant pump seal return flow instrument for determining total reactor coolant system leakage. This item was left unresolved pending NRC review of the licensee's past operability determination.

O1.6 Oconee Unit 2 Reactor Trip

a. Inspection Scope (93702)

The inspectors responded to and observed actions in the control room and the plant following a Unit 2 trip. The inspectors also interviewed personnel and attended meetings concerning the causes and response to the trip.

b. Observations and Findings

On June 3, 1998, Oconee Unit 2 experienced a reactor trip caused by a turbine trip on low vacuum. The result of the preliminary investigation was that the loss of vacuum was caused by maintenance activities on the #2 desuperheater flange. The licensee will issue Licensee Event Report (LER) 50-270/98-03 for this event. The inspectors will follow this issue in the LER and root cause evaluation.

Operators entered the emergency operating procedure (EOP) for the trip, stabilized the plant at hot shutdown conditions, and initiated PIP 2-O-98-2947. All systems responded as expected with only minor problems noted. The 230KV switchyard voltage decreased as a result of the Unit 2 loss of generation and high electrical grid loading; this is discussed in Section O2.2 below.

c. Conclusions

The inspectors concluded that plant systems responded appropriately following a Unit 2 reactor trip with only minor problems noted.

Unit 2 tripped due to loss of vacuum. The licensee was still investigating the maintenance and configuration control problems that caused the trip, with a LER to follow.

O2 Operational Status of Facilities and Equipment

O2.1 Unit 2 Reactor Building (RB) Hot Shutdown Inspection Prior to Startup

a. Inspection Scope (71707,71750)

The inspectors accompanied licensee personnel on two separate RB walkdown inspections for material condition prior to startup.

b. Observations and Findings

On May 19, 1998, and May 21, 1998, the inspectors accompanied licensee personnel on RB material condition inspections in Unit 2. The inspectors observed operations personnel complete a thorough and detailed inspection of the RB material condition. Using Procedure OP/0/A/1102/028, Reactor Building Tour, Revision 0, operations personnel identified numerous minor items. These items were determined not to impact unit startup and were entered into the licensee's work management system. The inspectors noted, however, that resolution of several of the items were not documented in the procedure.

c. Conclusions

The inspectors concluded that reactor building tours conducted at hot shutdown prior to Unit 2 startup were thorough and detailed. This indicates corrective actions dealing with material conditions in the reactor building have been effective in upgrading housekeeping.

The inspectors concluded that items found during Unit 2 reactor building tours at hot shutdown were properly dispositioned in the licensee's work management system, however, there was room for improvement in the procedure documentation of the resolution.

02.2 Oconee Switchyard Problems Due to Unit 2 Trip

a. Inspection Scope (93702)

Due to the June 3, 1998, Unit 2 trip, all Oconee units experienced a low 230 kilovolt (KV) switchyard voltage problem. This was the result of the loss of the generation capacity of Unit 2 coupled with grid demands. The inspectors observed Unit 1 operator actions during the event.

b. Observations and Findings

Following the Unit 2 trip, the alarm for low yard voltage, 230 KV SWYD ISOLATE ES PERMIT (SA-16/C-1), annunciated on Unit 1. The annunciator alarms at a switchyard voltage of 227.5 KV. Operators completed required annunciator response actions such as, contacting the Duke load dispatcher and verifying that Transformer CT-4, as well as the standby busses, were available. The operators responded to generator alarms making adjustments as necessary to stabilize generation and protect the plant. The load dispatcher altered grid load to assist in yard stabilization. The problem persisted for about 9 minutes and then this annunciator cleared.

Trend data obtained following the transient indicated that yellow bus voltage dropped until all three yellow bus under voltage (227.5) relays energized. The relays stayed energized until voltage returned to above the 230 KV set point. During the relay energization, had an emergency safeguards (ES) signal occurred on one of the three Oconee units, Keowee would have stripped off the grid and loaded to the affected unit. The licensee initiated PIP 0-098-3015 to investigate the grid problem and immediate dispatcher actions under high grid load conditions. These actions were appropriate for the circumstances. After the end of the inspection period, the licensee was planning to have a followup meeting to discuss grid transients.

During the grid transient, switchyard voltages did not drop to the external grid trouble protection system level (annunciator SA15/C-1). This level has a set point of 222.5 KV and six relays on the yellow and red busses energize below that voltage. Had voltage levels dropped to that point, the switchyard would have isolated and Keowee would have loaded to the yellow bus. Neither of the degraded voltage conditions should cause a reactor plant trip.

Unit 3 did not receive nor does it have an annunciator for 230 KV degraded voltage. Its electrical output to the 500 KV yard does not provide power for safety related loads as does the yellow bus of the 230 KV yard. The unit did receive a high excitation alarm at 415 Volts (as did Unit 1) with the operators responding to that occurrence properly. As part of the above PIP investigation, the licensee is reviewing whether or not Unit 3 annunciation should be provided on a 230 KV degradation or the Unit 1 and/or 2 annunciator response guide should be modified to alert Unit 3 of such 230 KV yard voltage degradation.

c. Conclusions

Licensee response to a degraded grid was prompt and complete. Operators responded well and technical followup on the encountered problems was also prompt and continued after the end of the inspection period.

O2.3 Unit 2 Valve Mispositioning

a. Inspection Scope (71707 and 37551)

On May 16, 1998, a misposition event occurred while Unit 2 was shut down below hot shutdown conditions, and was preparing for unit restart. The residents walked down the areas involved and discussed the known findings with the licensee.

b. Observations and Findings

During performance of PT/2/A/0202/11, High Pressure Injection (HPI) Performance Test, Revision 47, Valve 2HP-116 (HPI discharge cross connect) was found to be mispositioned. The operations test group had supposedly opened valve 2HP-116, which should have provided a flow path from the 2C HPI pump to the common HPI header. Once on this header, the 2C pump could then be tested and provide injection flow to the RCP seals. After the running 2B HPI pump was secured, the control room reactor operator reportedly received a low seal injection flow alarm that cleared when acknowledged. The idle 2A HPI pump subsequently auto-started, but was secured (without involving the control room senior operator) after the operator verified normal flow. Very shortly after that, all individual RCP seal injection flows, total seal injection flow, and the 2C HPI header pressure control alarms annunciated. At that time, the operator restarted the 2A HPI pump. From the auto-start of the 2A HPI pump to its restart took 21 seconds. Testing was stopped and the plant was placed in a safe condition. Due to redundant as-built design, no RCP seal damage occurred.

Investigation into why the 2C HPI pump could not satisfy seal flow needs, revealed that valve 2HP-116 was closed. The valve had been modified this outage to be remotely operated by a cable arrangement. An equivalent valve on Unit 3 took 39 turns to open, but the Unit 2 valve was found to be only opened about 15 turns before the 2C HPI pump was started. The Unit 3 valve had a mounted placard by the manual operator indicating it takes 39 turns to open. The Unit 1 and 2 valves had no such placard. The licensee initiated PIP 2-98-2654 and operational guidance was provided. In addition to this Unit 2 PIP, it was revealed that four additional PIPs had been written previously against the Unit 3 valve which could be applicable to all three units. These were:

4/29/98	3-098-2315	3HP-116 Does Not Have Position Indication
8/20/97	3-097-2615	Reliability of Shear Pin in 3HP-116 Handwheel Questionable

5/04/97	3-097-1431	3HP-116 Valve Operator Tie-Wrapped to Safety Related Piping
3/10/97	3-097-0865	Flex Cable on Remote Operator too Long

Until the licensee completes its evaluation of the operator actions regarding the initial securing of the 2A HPI pump and reviews the details of the remote cable operator modification implemented on valve HP-116, this shall be identified as URI 50-269,270,287/98-06-04: Unit 2 Valve Misposition Issues.

c. Conclusion

During the period, there was a mispositioning of valve 2HP-116 during Unit 2 high pressure injection performance testing. Pending further evaluation of related issues, this has been identified as an unresolved item.

02.4 Penetration Room Drain Valve 2LWD-444 Misposition

a. Inspection Scope (71707)

The inspectors reviewed documents and interviewed personnel in response to the identification of the Unit 2 east penetration room floor drain isolation valve 2LWD-444 being found mispositioned.

b. Observations and Findings

On June 9, 1998, during the performance of PT/2/A/0152/002, Reactor Building Spray Valve Stroke, Revision 4, a non-licensed operator (NLO) had been sent to open valve 2LWD-44 and had found the valve already open. The valve was required to be normally closed. The NLO closed the valve following the completion of the test.

PIP 2-098-3039 and an operability evaluation were initiated. Present operability was satisfied once the valve was closed. Determination of past operability was still in progress at the end of the inspection period. This item will be followed as URI 50-270/98-06-05: 2LWD-444 Mispositioning May Affect Penetration Room Ventilation.

c. Conclusions

The licensee identified a mispositioned valve that may affect the penetration room ventilation system. This item was left unresolved pending completion of the licensee's investigation and further NRC review.

04 Operator Knowledge and Performance

04.1 Temporary Defenses During Unit 2 Startup

a. Inspection Scope (71707)

The inspectors reviewed the temporary defenses in place during the Unit 2 startup as part of the Oconee Recovery Plan.

b. Observations and Findings

As part of the Oconee Recovery Plan, the licensee initiated three temporary defenses to prevent events. Temporary defense number 1 was for operations management to conduct six hours per shift of direct observation during non-outage time. Temporary defense number 2 was for continuous management oversight during changes in power level and RCS heatup or cooldown. Temporary defense number 3 was initially implemented to provide continuous independent monitoring of RCS inventory during plant startup and shutdown. This last defense was changed on March 10, 1998, to have operators perform periodic monitoring every 2 hours.

The inspectors verified that operations management was present in the control room for a Unit 2 heatup and a Unit 1 power reduction on May 21, 1998, and that operators were periodically monitoring RCS inventory and logging the results in their periodic instrument surveillance. The managers involved in the overview process were knowledgeable of proper operations conduct and were providing real-time feedback to the crews and to upper management. Operations management was also present in the control room for the approach to criticality of Unit 2 on May 22, 1998. The inspectors verified that operations management oversight personnel discussed their findings with the control room senior reactor operator (SRO). The continuously operating computer software that constituted the RCS monitoring was a positive means of cross-checking control room instrumentation for detecting unintended changes. The operators were diligent in using the software and logging the observed results. The inspectors also noted that no major operational events occurred during this Unit 2 outage.

c. Conclusions

The licensee's implementation of temporary defenses from the Oconee Recovery Plan for continuous management oversight during Unit 2 startup and for periodic monitoring of Unit 2 reactor coolant system inventory were considered good. This Recovery Plan item is considered closed.

04.2 Inadvertent Start of Engineered Safeguards (ES) Pump

a. Inspection Scope (71707)

The inspectors interviewed personnel and reviewed procedures associated with the inadvertent start of the Unit 1A Low Pressure Injection (LPI) pump during ES testing.

b. Observations and Findings

On May 29, 1998, a reactor operator (RO) and an instrumentation and electrical (I&E) person were performing Procedure IP/0/A/0310/12B, Engineered Safeguards System Logic Subsystem 1 LPI Channel 3 On-Line Test, Revision 28. Step 10.9.7 states to start the 1A Low Pressure Service Water (LPSW) pump by depressing the manual push-button and verifying the start. The RO, with the I&E person observing, inadvertently started the 1A LPI pump at 4:18 p.m. The RO noted that the 1A LPSW pump had not started and realized that he had inadvertently started the 1A LPI pump.

The control room SRO was informed and he gave direction to stop the 1A LPI pump. Total run time for the 1A LPI pump was 22 seconds as recorded by plant computer. The RO and the I&E personnel had completed testing for the 1B and 1C LPSW pumps correctly. The RO was removed from licensed duties pending a full review of the incident and remediation.

This is a repeat missed action for the RO. On November 10, 1997, this same individual erroneously placed the Unit 2 Turbine Driven Emergency Feedwater (TDEFW) pump switch in "pull-to-lock" at 1:20 p.m. The individual had intended to place the Unit 1 TDEFW pump switch in "pull-to-lock" in support of maintenance on valve 1MS-87. The Unit 1 and Unit 2 SROs were informed, the Unit 2 TDEFW switch was realigned to AUTO, PIP 5-097-4003 was written and the limiting condition for operation (LCO) was entered and exited for the 40 seconds that the switch was misaligned. Corrective actions for this event included counseling the individual on the use of the licensee's self-checking program, and the use of peer checks.

The recent event was self-disclosing and appears to be similar to the previous event. The inspectors determined that both of these events were caused by the individuals lack of attention to detail. This will be identified as VIO 50-269/98-06-06: Failure to Follow Procedure During ES Testing.

c. Conclusions

Lack of attention to detail resulted in a violation of procedure requirements and the inadvertent starting of an engineered safeguards component.

08 Miscellaneous Operations Issues (92901, 92700)

08.1 (Closed) URI 50-269,270,287/97-18-12: Refueling Outage Surveillance (Notice of Enforcement Discretion (NOED) for Units 2 and 3)

(Closed) LER 269/98-03: Missed Surveillance Due to Non-Literal Interpretation of Technical Specifications

On January 15, 1998, the licensee submitted a TS change request in accordance with 10 CFR 50.90. The requested amendment titled, Request for Technical Specification Amendment for Test and Calibration,

consisted of a proposed one-time extension to the instrument channel test frequency for several instruments and engineering safeguards channel surveillances. The NRC had processed that change in accordance with the normal thirty-day comment period. Several days later, the licensee discovered more TS driven surveillances that had not been included in the January 15 submittal. The licensee engaged the NRC in discussion about including these additional items in the January 15, 1998, submittal, but due to NRC process requirements, those additional surveillances could not be included in a timely manner to support Unit 2 surveillance due dates. The end of initial TS surveillance grace limit for the potentially overdue low pressure injection cooler performance test surveillance was February 14, 1998, while the unit refueling was scheduled for March 13, 1998. When questioned by the licensee if surveillances scheduled to be completed at refueling outages could not be performed at other times, NRC indicated that surveillances specified for refueling per TS must be completed during refueling outages. In the past, the licensee had performed some tests on occasions while the units were in a non-refueling outage status. Consequently, on January 30, 1998, the licensee submitted a request for a NOED concerning refueling outage frequency surveillances. NRC had verbally granted the discretionary enforcement to the licensee on January 30, 1998. After the granting of discretionary enforcement, the licensee submitted a February 2, 1998, TS change altering the surveillance frequency dates. The change, which affected 93 surveillances, aligned the Oconee TS with the NRC approved standard TS. The NRC performed a review of the surveillance process, which is discussed in Inspection Report 50-269,270,287/98-01. The licensee addressed this issue in associated LER 269/98-03, on March 2, 1998.

Prior to implementation, the inspectors had reviewed the proposed new TS for content. The licensee appeared to have identified all the locations in the TS where refueling, refueling outage, or "RF" (abbreviation for refueling frequency) had been used. The licensee had submitted a page change to the last submittal correcting a paragraph 4.2.2 change back to refueling outage frequency from eighteen months. These involved inspections of the core barrel to core support shield caps that should be inspected each outage. Additionally, the inspectors verified that the licensee had completed or scheduled (PIP 0-098-464) all the actions indicated in the associated LER.

Reviewing the paper regarding the NOED, the inspectors determined that the scheduling of the performance of surveillance tests every 18 months instead of during refueling outages was a violation of TS prior to the NOED. However, as stated in the LER and the NRC documentation, the performance of the surveillances had been accomplished and there was no safety impact to the plant or its performance. Consequently, 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. This is identified as NCV 50-269,270,287/98-06-02: Failure to Properly Implement Surveillance Requirements. The associated URI and LER are considered closed.

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:

- PT/2/A/0251/024 HPI Full Flow Test, Revision 6
- PT/0/A/0300/001 Control Rod Drive Trip Time Test, Revision 13
- PT/0/A/0711/001 Zero Power Physics Test, Revision 31
- TT/2/B/0326/001 ICS/NNI Transient Testing at Power, Revision 0
- TT/2/B/0326/002 ICS/NNI Loss of Power Testing at 25 Percent Reactor Power, Revision 0
- OP/2/A/1103/011 Drain and Nitrogen Purge of RCS, Revision 37
- OP/2/A/1104/001 Core Flood System Enclosure 4.1 Filling CFTs Using HPI Pump, Revision 44
- PT/2/A/0152/020 Main Steam Line Break Circuitry Valve Stroke Test, Revision 004
- CP/0/B/5200/048 Resin Recovery System Operation, Enclosure 5.6 Decant Monitor Tank Release to Keowee Tailrace LWR 98-127, Revision 58
- MP/0A/1840/040 Pumps-Motors-Misc Components-Lubrication-Oil Sampling-Oil Change, Revision 11
- PT/1/A/0600/025 Motor Driven Emergency Feedwater Pump Automatic Recirculation Valve (ARC) Test, Revision 1
- WO 97072631 Repair and Test Group 5 Rod 7
- PT/O/A/0300/001 Control Rod Drive Trip Time Testing, Revision 13
- IP/2/A/0330/002D Control Rod Drive System Patching Scheme and Functional, Cabling, and Patching Test, Revision 20
- PT/2/A/0600/012 Turbine Driven Emergency Feedwater Pump Test, Revision 54

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 Control Rod Drive Mechanism (CRDM) Repair

a. Inspection Scope (62707, 37551)

The inspectors observed control rod movement during startup and trip time testing, as well as reviewed documentation of the testing. Repairs to CRDMs were discussed with the system engineer.

b. Observations and Findings

Prior to the outage, seven CRDMs were identified as needing repair due to slow trip times during testing. One CRDM had already received a new Type A thermal barrier and the other six were to be repaired by replacing the old thermal barriers with the modified Type A barrier. The trip times of these rods were in excess of the 1.4 seconds administrative limit, but below the TS requirements of 1.66 seconds.

Prior to disassembly, seven additional CRDMs were identified with flange leaks. As a preventive measure, six of these received the modified Type A thermal barrier while they were removed. One CRDM had the flange leak repaired. This repair method was chosen to prevent having to remove the reactor vessel level indication system flange on that side of the CRDM.

As a recommendation from PIP 1-098-0259, Unit 1 failure of Group 5 Rod 7, the thermal barrier procedure had been revised. The revision required inspection of the rotor assembly thrust bearing retaining nut locking support washer crimps. This required the rotor assembly to be removed. While the assembly was removed, penetrant testing (PT) was performed on the bi-metallic welds in the motor tube, inside diameter and outside diameter (OD) of the welds in the lower weld, and the OD of the upper weld. These PT inspections were in response to a crack found in a corresponding weld at Prairie Island. PT inspections were completed on the twelve CRDMs, that received new thermal barriers, with no indications of cracking identified.

CRDM trip time test results were good, with all CRDM drop times indicating less than 1.4 seconds and no problems or concerns indicated.

c. Conclusions

The revision of the thermal barrier procedure by maintenance to complete additional inspections was seen as a positive. Subsequent testing of the repaired CRDMs did not indicate any problems.

Engineering support of the CRDM changeout and evaluation of the CRDMs was seen as a positive.

The use of operating experience feedback in the inspection of the CRDM motor tube welds was seen as a positive.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 1 and 2 Low Pressure Service Water Pumps Bearing Failures

a. Inspection Scope (62707, 37551)

The inspectors interviewed personnel, reviewed data, and observed maintenance and engineering activities associated with the failure of the B and C LPSW pump bearings for Unit 1 and Unit 2.

b. Observations and Findings

On June 3, 1998, the B LPSW pump bearings were replaced due to indications of wear and oil contamination. On June 6, 1998, maintenance personnel monitoring the B LPSW pump bearings noted an increase in vibration and obtained an oil sample. The oil sample indicated wear and contamination of both bearings. PIP 5-098-3006 was initiated, a FIP team was formed, and the B LPSW pump bearings were replaced.

Preliminary results of the FIP team investigation indicate three possible contributing factors to the bearing failures: a misalignment of the pump to motor, a shift in the magnetic center or improper setup of the motor, and the wrong type of bearings installed in the pump. Pending further NRC review, this issue is identified as URI 50-269,270/98-06-07: LPSW Pump Bearing Failures.

c. Conclusions

The inspectors identified an unresolved item concerning the failure of and maintenance on the Unit 1 and 2 Low Pressure Service Water pumps.

M3 Maintenance Procedures and Documentation

M3.1 Procedure for Cleaning Siphon Seal Water (SSW) Strainers

a. Inspection Scope (62707, 71707)

The inspectors followed the circumstances surrounding the initial cleaning of the SSW strainers.

b. Observations and Findings

During the most recent Unit 2 outage, the licensee installed the SSW system under nuclear station modification (NSM) ON-52932 Part AM3, SSW Headers in the Essential Siphon Vacuum (ESV) building. The system was placed in service on May 1, 1998. Included in the installation were two duplex strainers for filtering seal flow to the condenser circulating water (CCW) pumps and ESV pumps. On May 18, 1998, the indicated differential pressure on one side of one of the strainers exceeded the maximum reading on the scale. When attempting to clean the strainer, the licensee discovered there was no procedure available to complete the job. On May 19, 1998, the indicated differential pressure on the other side of the same strainer exceeded the maximum reading on the scale. In this condition, the potential existed for a clogged strainer to block seal flow to the ESV pump. The licensee determined this did not happen and seal flow was maintained to the ESV pumps. The licensee issued PIP 0-098-2691 and cleaned the strainer using the work order (WO) process.

The inspectors reviewed the PIP, WO, and NSM final scope document. The inspectors also talked with operations, maintenance, and engineering personnel involved. Maintenance personnel had begun development of Procedure MP/0/A/1600/028, Strainer - Mueller - Removal, Cleaning and Installation, Revision 0, on April 21, 1998, and independently reviewed it on April 23, 1998. While attempting to resolve comments, maintenance personnel stopped development of the procedure after engineering indicated the strainers were being evaluated for replacement.

NSD 301, Nuclear Station Modifications, Revision 13, stated in Section 301.3.1.11 that the superintendent of maintenance was responsible for identifying and developing any mechanical procedure revisions, including new procedures, required as a result of modification work. NSD 301, Section 301.6.3.7, stated that prior to acceptance of a modification by the operational controlling group, all procedure revisions would be completed as appropriate. The inspectors found that Procedure MP/0/A/1600/028 was not completed prior to acceptance of the modification.

The inspectors found that the details of the process within the maintenance department governing the identification and revision of procedures affected by modifications were not controlled by procedure. The inspectors also found that the persons responsible for revising a procedure and the persons responsible for signing for procedure completion as required by NSD 301 were from different groups within maintenance.

TS 6.4.1.e requires the station to be maintained in accordance with approved procedures for maintenance of equipment which could affect nuclear safety. The failure to issue Procedure MP/0/A/1600/028 after completion of the SSW modification on Unit 2 is a violation of this TS and is identified as VIO 50-270/98-06-08: Failure to Complete Procedure Following SSW Modification.

c. Conclusions

The inspectors identified a violation for failure to issue a maintenance procedure to clean the system strainers following installation of the Unit 2 siphon seal water system. This failure resulted from a weakness in the process for implementing procedure changes following plant modifications.

M8 **Miscellaneous Maintenance Issues** (92902)

M8.1 (Closed) VIO 50-269,270,287/97-02-03: Failure to Perform Procedure Prerequisites

In April 1997, (IR 50-269,270,287/97-02, Section M1.4), Elevated Water Storage Tank (EWST) drain down activities were being performed as called for by an EWST inspection procedure. While operations was completing the main section of the procedure, the inspectors noted that several of the prerequisite steps had not been completed. Some of the prerequisite steps which had not been completed contained activities which provided reasonable assurance lake levels would be maintained at a level needed for proper LPSW siphon flow upon a loss of site power. A subsequent event root cause evaluation, PIP 0-097-1215, attributed the problem to: (1) an inadequate turnover between operations and maintenance; (2) a lack of understanding as to who was responsible for overall control and coordination of inspection procedure activities; and (3) inadequate planning and scheduling of work tasks. The inspectors reviewed the following completed licensee corrective actions:

- Revisions to the EWST inspection procedure revisions were performed. These revisions highlight and relocate various configuration requirements/steps into the prerequisite section of the procedure.
- Personnel who were involved in the event were counseled on their use of and adherence to facility procedures.
- All shifts received training, as part of operations requalification, on management expectations regarding procedure control, coordination, use, and adherence.

The inspectors found that corrective actions for a violation which involved a failure to perform procedure prerequisites when draining the elevated water storage tank were good. This item is closed.

M8.2 (Closed) VIO 50-269,270,287/97-05-03: Failure to Provide Adequate Corrective Actions

This violation contained two examples. In May 1997 (IR 50-269,270,287/97-05, Section M1.3, Example number 1) the Unit 3A and 3B HPI pump mini-flow orifice assemblies were noted to be severely damaged. The noted internal assembly damage was caused by inadequate design and subsequent flow-induced erosion. A similar problem with these orifices was noted by the licensee in January 1975; however, the licensee failed

to place these mini-flow orifices into an augmented inservice test or any other periodic test or examination program. An event root cause evaluation (PIP Form 3-097-1688) attributed the problem to an inadequate orifice design. The previous design allowed for movement between the orifice plate and the spacer pieces and this movement contributed to erosive effects between the components. As the spacer eroded, a larger gap formed and this accelerated the general erosion process which produced an eventual failure of the assembly. The inspectors reviewed the following completed licensee corrective actions for example number one of the violation:

- The subject orifice assemblies were replaced with new assemblies.
- A routine inspection program (consisting of both baseline and periodic radiographies) was performed during the most recent Unit 1 outage. Similar testing was performed on Unit 2 and is planned for Unit 3 during its upcoming refueling outage.

In June 1997, (IR 50-269,270,287/97-05, Section M1.3, Example number 2), a licensee inspector noted that radiographs of a repaired Unit 3 HPI mini-flow orifice assembly did not present 100 percent coverage. The 100 percent coverage was required by ASME code. The inspectors noted that this issue was similar to an event described in VIO 96-17-09, LPSW Modification Did Not Meet the American Society of Mechanical Engineers (ASME) Code NDE Requirement. A root cause evaluation (PIP 3-097-1688) attributed the mini-flow orifice assembly problem to inadequate communications between licensee engineering and NDE inspectors and informal documentation of decisions to perform another type of NDE [ultrasonic testing (UT)] than that called for in the original test package [a radiography testing (RT)]. The inspectors reviewed the following completed licensee corrective actions for example number two of VIO 97-05-03:

- A UT was completed on the subject weld to satisfy code requirements.
- An operability review was completed to determine the actual operability of the Unit 3 HPI system.
- A revision to the licensee's welding manual was performed to note that detailed directions are to be provided for non-routine/complex evolutions.
- A review of existing licensee NDE procedures was performed.
- A method for requesting "not normally performed NDE inspections" was developed.

The inspectors found that corrective actions for a two-part violation involving a failure to provide adequate corrective actions for both an eroded high pressure mini-flow injection orifice and an inadequate weld on an orifice assembly were good. This item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Post-Modification Testing of ESV Modifications

a. Inspection Scope (71707, 62707, 37551)

After initial testing of this modification (IR 50-269,270,287/97-05, Section E8.3), several interim changes were made. The inspectors observed the testing of the changes.

b. Observations and Findings

In PIP Form 2-098-2415, the licensee identified that the float valves in the ESV system were not opening up fully during certain conditions. During high air in-leakage testing, the float valves remained partially closed creating a minor flow restriction.

Over several iterations, a spare float valve for the system was temporarily modified and tested in a system mockup in accordance with engineering instructions and valve vendor support.. The engineering support of the changes was real time and meticulous in confirmation of system performance. After mockup testing, prior to returning the actual system to service, the changes were satisfactorily trial tested in the actual system configuration. The changes were documented in the NSM with supporting calculation OSC-7172. The inspectors were present for the satisfactory trial testing and observed system performance over several days.

c. Conclusion

Engineering resolution of a minor problem with the essential siphon vacuum system was good. Testing met acceptance criteria.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 2 Incore Quadrant Power Tilt (QPT)

a. Inspection Scope (37551)

On May 23, 1998, licensee personnel commenced a power increase on Unit 2 for power escalation testing. An unexpected positive core QPT of 7.48 percent was detected in the XY quadrant at 15 percent of full power. The licensee had designed the core load such that the QPT should have been close to zero. The inspectors reviewed procedures, TS, the results of the QPT investigation, and observed reactor engineering activities.

b. Observations and Findings

The inspectors discussed TS 3.5.2.4, Quadrant Power Tilt, with licensee personnel. The TS 3.5.2.4.a stated, that the maximum positive QPT shall not exceed the steady state limit provided in the Core Operating Limits

Report (COLR). TS 3.5.2.4.b stated in part, that if the maximum QPT exceeds the steady state limit but, is less than the transient limit provided in the COLR, then reduce the QPT below 100 percent within 2 hours to within the steady state limit or reduce thermal power and overpower trip set points by 2 percent for each 1 percent of QPT in excess of the steady state limit. TS 3.5.2.4.c stated in part, that the QPT shall be reduced within 24 hours to within its steady state limit or, reduce thermal power to less than 60 percent power within 2 hours and Overpower Trip Set points within the next 4 hours to 65.5 percent.

The inspectors observed that the steady state limit for incore QPT was 7.69 percent from zero to 30 percent power and 3.5 from 30 to 100 percent power. The QPT in the XY quadrant was positive 4.32 percent at 25 percent power with a corresponding negative QPT in the opposite ZW quadrant. With a positive QPT of 4.32, the 3.5 limit would be exceeded if power were raised above 30 percent.

With past core QPT history, licensee experience indicated that the QPT problem would remedy itself at higher power levels. TS 3.5.2.4.c limits would apply at higher reactor power limits. In light of the unexpected, non-zero, QPT values, two licensee actions took place. First, the licensee provided interim guidance to the operators regarding QPT limits via a change to the COLR. The licensee performed a change to the COLR that established new steady state limits as follows: 7.69 percent from zero to 30 percent power, 5.01 percent from 30 to 60 percent power, and 3.5 percent from 60 to 100 percent power. Secondly, due to the unexplained QPT presence and incore instrumentation questions, the licensee initiated PIP 2-098-2776 and established a FIP to perform the following:

- Investigate the cause of the Unit 2 reactor power QPT.
- Determine why the QPT was not behaving as expected.
- Develop recommended corrective actions to reduce QPT (if possible).
- Recommend actions to prevent recurrence.

The FIP team made several recommendations such as: minimize cross-core shuffles in high power core locations when previous cycle QPTs exceeded 2 percent; provide additional subgrouping of incore background detector signals for better calculation of flux background corrections; and in the COLR pursue more flexible QPT limits as a function of power level.

Licensee investigation included monitoring core difference in temperatures, boron concentrations, rod worth calculations, incore instrument string age and replacement history, and core loading information for assembly power. Following analysis of the above indications the licensee concluded the most reasonable contribution to the QPT was the age of certain incore instruments. Following discussions with the vendor and the General Office, Cycle 13 subgroup incore depletion correction factors were adjusted.

The licensee tested and reconfigured incore detector strings based on vendor information to reduce the apparent QPT. After licensee analysis, there was still about a 2 percent calculated QPT. The licensee indicated this was to be expected due to some less than optimal fuel assembly shuffles during reload. After Oconee management concurrence, Unit 2 power was increased with both the licensee and inspectors monitoring QPT levels. The QPT did reduce to within the previous COLR limits (less than 3.5 percent). Licensee actions were acceptable for the given conditions.

c. Conclusions

The inspectors concluded that the failure investigation for the incore power QPT produced adequate conclusions and findings, and that the recommendations were technically sound.

E2.2 Unit 2 Reactor Coolant Pump (RCP) Inspections

a. Inspection Scope (71707, 62707, 37551)

Previous licensee findings indicated impeller erosion on the Unit 1 impellers (IR 50-269,270,287/97-16, Section E1.1). During the current Unit 2 outage the licensee completed RCP impeller inspections as necessary to reliably operate for the next fuel cycle. This included in situ inspection of the 2B1 RCP impeller and removal and inspection of the 2A1 impeller. The 2A1 impeller was changed out due to shaft bowing that had caused the RCP to have elevated vibration levels over the last several fuel cycles. The inspectors observed portions of the 2A1 RCP change out, reviewed the video-taped inspection of the 2B1 RCP impeller and one spare impeller, and visually inspected another spare impeller. Both inspected spares were removed from Unit 2 in 1988. Further, the inspectors reviewed and discussed with the licensee the evaluation and analysis of the inspection findings on the Unit 2 RCPs and those implications regarding the Unit 3 RCPs.

b. Observations and Findings

The 2B1 RCP impeller position was judged by the licensee to have sustained the highest erosion wear. This was interpolated from Unit 1 inspection findings and pump location information. The 2B1 RCP historically had the highest run times from single pump operation due to the fact that it was first pump turned on for pressurizer spray needs. Its inspection indicated high levels of wear, but the wear levels were relatively less that those seen on the failed 1A1 RCP impeller (1A1 had run for 27 years while the 2B1 had run since 1988 at better net positive suction head (NPSH) pressures). Per Calculation OSC-7180 of April 27, 1998, the pump manufacture, the nuclear steam system supplier, and Oconee engineering agreed that the 2B1 impeller was satisfactory for the upcoming fuel cycle operation. The inspectors concurred in the rationale used to support this determination.

Upon return to service, all four Unit 2 RCPs operated at acceptable vibration levels. The 2B1 RCP was running at higher that normal, but

acceptable vibration levels. The inspectors reviewed the vibration data at various pump conditions, as well as other parametric data. For the most part, these were acceptable. The exception to this was the seal cavity pressure on RCP 2A1 discussed in Section O1.5 of this report.

The inspectors reviewed procedure changes that were made prior to Unit 2 RCP return to service. These procedure changes were made to limit pump run time at low NPSH conditions and to provide operational curves for proper pump operation (previously, a violation had been identified on the Unit 1 procedures). The procedures were: OP/0/A/1108/01, Curves and General Information, Revision 28; OP/2/A/1103/06, Reactor Coolant Pump Operation, Revision 46; and, OP/2/A/1102/001, Controlling Procedure for Unit Startup, Revision 198 (Enclosures 4.12, Startup Checklist, and 4.5, Unit Startup to 200 Degree F/300 psig). Further, the inspectors reviewed the training for the above changes and found that acceptable. The procedure changes were appropriate and of sufficient detail.

c. Conclusions

During the Unit 2 outage the licensee adequately completed RCP impeller work and inspections as necessary to reliably operate for the next fuel cycle.

The licensee effectively planned and managed work on the Unit 2 RCPs and associated activities.

E3 Engineering Procedures and Documentation

E3.1 Core Operating Limits Report Changes

a. Inspection Scope (37551, 71707)

Part of the licensee's actions regarding the quadrant power tilt on Unit 2 was to change the tilt limits in the COLR. The inspectors reviewed the changes and 10 CFR 50.59 evaluations.

b. Observations and Findings

On May 27, 1998, the licensee performed a change (Revision 8) to the Unit 2 Cycle 17 COLR that added a steady state full incore quadrant power tilt limit for 30-60 percent power. The licensee screened the changes against 10 CFR 50.59 and determined they did not: change the facility as described in the Safety Analysis Report (SAR), change procedures as described in the SAR, or create a test or experiment not described in the SAR. After the inspectors questioned the screening, the licensee performed an unreviewed safety question (USQ) determination and determined no USQ existed.

The inspectors reviewed the 10 CFR 50.59 screening against NSD 209, 10 CFR 50.59 Evaluations, Revision 7. Section 209.10.4 contained guidance on how to determine whether or not an activity changed a procedure as described in the SAR. The section stated that SAR procedures included anything described in the SAR that defined or described activities or

controls over functions, plant configurations, tasks, reviews, or tests. Table 209-1 of this procedure listed the COLR as a SAR document. The inspectors determined that changing the limits in the COLR changed a control over plant configuration and should have resulted in an unreviewed safety question (USQ) determination. This was not in compliance with NSD 209 and is identified as VIO 50-270/98-06-09: Failure to Perform Safety Evaluation.

c. Conclusions

The inspectors identified a violation for failure to follow the procedure for safety evaluations performed under Title 10 Code of Federal Regulations Part 50.59 when changing the core operating limits report.

E7 Quality Assurance in Engineering Activities

E7.1 Problem Identification Process Impacting Unit 2 Startup

a. Inspection Scope (37551,92903)

The inspectors reviewed and discussed with licensee personnel corrective actions in PIPs that were identified as impacting the Unit 2 startup from refueling.

b. Observations and Findings

The licensee identified 35 corrective actions contained in PIP forms that impacted the Unit 2 restart. The review included the corrective actions specified in the PIPs from various site organizations. Among these were the following:

- PIP 1-96-0357, corrective action 3, required a walkdown by civil engineering of piping attached to the RCS. The walkdown was to verify no thermo-expansion interference existed that could result in an unisolable RCS leak.

- PIP 1-96-0405, corrective action 8, perform revised procedure IP/O/B/0275/010, Condensate System Flow Calibration, Revision 22, on feedwater and condensate control valve 2C-61.

- PIP 1-96-1982, corrective action 3, required the revising of the emergency power switching logic tests for all units to include parallel contact verification.

- PIP 1-94-0602, corrective action 4, required that three valves in the low pressure service water system be replaced with valves less susceptible to failure from vibration.

The inspectors found from the reviews that the corrective actions were technically sound and were tied to the applicable Unit 2 restart conditions.

c. Conclusion

Prior to the Unit 2 restart, the licensee completed all necessary problem report corrective actions. The 35 reviewed problem reports were technically sound and used good engineering judgement.

E7.2 Review of HPI/LPI Self-Initiated Technical Audit

a. Inspection Scope (40500)

The inspectors reviewed several PIPs associated with audit SA-97-10(ON)(SITA)(HPI/LPI), which was the Self-Initiated Technical Audit (SITA) performed on the HPI and LPI systems. The inspectors also reviewed the status of licensee corrective actions for resolving the SITA findings assigned to engineering.

b. Observations and Findings

The HPI/LPI SITA was performed during the period from November 10, 1997, through December 11, 1997. This SITA was performed by the Regulatory Audit Group of the Nuclear Assessment and Issues Division in the General Office. The purpose of this SITA was to assess the operational readiness and functionality of the HPI and the LPI systems and interconnecting systems. The HPI/LPI SITA identified 41 findings and seven recommendations. The audit findings and recommendations were documented in Oconee PIPs. The licensee had initiated corrective actions to resolve the HPI/LPI SITA findings and recommendations.

Some of the SITA findings indicated that the corrective action program, including operating experience, was ineffective in preventing recurrence of several equipment and programmatic issues. The inspectors noted that the SITA findings also indicated that there were weaknesses in other areas. These other areas included the inservice test program, the design control program involving 10 CFR 50.59 safety evaluations and the translation of design information and calculation assumptions into emergency operating procedures. The inspectors further noted that two issues from the HPI/LPI SITA involving the borated water storage tank (BWST) level instrumentation and reactor building emergency sump (RBES) water level indication and EOP guidance were identified as URI 50-269,270,287/98-02-10.

The inspectors made the following observations regarding the PIP process during review of the HPI/LPI SITA findings:

(1) PIP 0-098-0140, dated January 12, 1998, identified a number of non-conservative inputs during a review of calculation OSC-4616, Letdown Storage Tank Operating Curve-Maximum Allowable Pressure vs Indicated Level, including, but not limited to, the volume of piping connected to the letdown storage tank (LDST) which may be gas filled. The calculation used nominal dimensions from the outline drawings instead of as-built dimensions in determining the amount of liquid in the tank. The problem description included the statement that the issued calculations were discussed by the

systems engineer and the audit team, who reached the conclusion that these issues were not significant enough to affect operability. There was no information included to support this conclusion. The PIP was screened as a less significant event (LSE) Category 3, which did not require an operability evaluation by operations. The problem evaluation concluded that the cause was unknown, conjecturing that the listed concerns could have been properly considered and dismissed as insignificant. The person performing the evaluation stated that this was just a possibility, that the apparent cause was indeterminate.

(2) PIP 0-098-0150, dated January 12, 1998, initially documented the issues concerning the BWST level instruments. The PIP form indicated that the HPI/LPI SITA team and Systems Engineering had discussed the issues identified in the PIP and concluded that the significance of the issues did not justify an operability evaluation. There was no documented basis to support the conclusion as to why this issue did not represent an operability concern. These issues were later determined by the licensee to be a condition that was outside the design basis and was an operability concern. The licensee initially reported this issue to the NRC as LER 50-269/98-06. As discussed above, this issue is also being reviewed by the NRC as URI 50-269,270,287/98-02-10.

(3) PIP 0-098-0159, dated January 13, 1998, identified that design controls were not established to ensure the minimum head curve requirements of ASME Section XI inservice testing for the HPI and LPI pumps. The PIP form stated that minimum head curve requirements of calculation OSC 5691, LPI Flow Input to B&W New Fuel Analysis, were not satisfied by the quarterly ASME Section XI tests of the LPI pumps. The licensee reviewed the testing program required action values for minimum developed head for the pumps and determined that for five of the nine LPI pumps on site, the procedure required action value was below the minimum head curve value specified in the calculation. The PIP also identified that the minimum head curve requirements of calculation OSC 5723, HPI Flow Input to B&W New Fuel Analysis, were not satisfied by the licensee's test procedures. The licensee determined that for all but one of the HPI pumps, the procedure required action value was below the minimum head curve value specified in the calculation. The problem description for the PIP included the statement that the issues had been discussed by the audit team and systems engineering and a consensus had been reached that the significance of these issues did not constitute an operability issue. The licensee screened this PIP as a LSE, with no operability or reportability determination being performed. The inspectors discussed this issue with the system engineer. The decision that this issue was not an operability concern was based on the system engineer's experience with the system. The inspectors determined from this discussion that the issue was not researched to verify that actual test data was conservative with respect to the minimum head curves specified in the calculations. The licensee's problem evaluation determined the cause of the noted problem was unknown.

Conjectural causes were presented, but the licensee had no evidence to support any specific cause. The licensee's planned corrective actions will be to revise the procedures to include the minimum head curves from the calculations. After the inspectors questioned the adequacy of the documented operability determination, the licensee updated the PIP form problem statement to provide a documented basis for why there was not an operability concern for either the HPI or LPI pumps.

(4) PIP 0-098-0176, dated January 13, 1998, identified a concern that inadequate 10 CFR 50.59 evaluations were performed for several LPI and reactor building spray (BS) procedures which created recirculation alignments to the BWST during surveillance testing. The PIP problem description further stated that the concerns identified indicated that the procedures potentially constituted USQs. The inspectors noted that this PIP was screened by the Oconee centralized screening team (CST) as a LSE rather than a more significant event (MSE). Being screened as a LSE PIP meant that this concern was not required to be evaluated for either operability or reportability. The inspectors also questioned whether the screening category for this PIP was consistent with the problem description (i.e., inadequate 10 CFR 50.59 evaluation and potential USQs). There was no documented justification as to why this PIP was screened as a LSE, other than the statement that "This event was reviewed by the CST and does not meet the MSE significance criteria." Based on this statement made by the CST, the inspectors questioned whether any concern identified as a potential USQ could meet the MSE significance criteria. Licensee personnel indicated that, in general, potential USQ concerns would meet the significance criteria for a MSE PIP. The licensee further stated that the concerns identified in PIP Form 0-098-0176 had been reviewed during the HPI/LPI SITA and the justification for why there was not an USQ or an operability concern (although not documented) was discussed with the SITA team and resolved during the audit. The inspectors concluded that this PIP did not have an adequately documented justification to support the screening as a LSE Category 3 PIP, which precluded the performance of USQ, operability, and reportability evaluations. After the inspectors raised questions regarding the documentation in this PIP, the licensee updated the problem description on June 4, 1998, to provide a documented justification for why the issues identified in PIP 0-098-0176 were not considered to be USQs or operability concerns.

The above PIPs identified issues which had the potential of affecting operability of the HPI and LPI systems. The PIP forms were not reviewed for operability, based on the judgement of engineering that operability concerns did not exist. This was stated in some of the PIPs, but there was no documented basis included in the PIPs to substantiate these conclusions. This weakness was observed in several of the PIPs generated for the HPI/LPI SITA findings.

(5) During a previous NRC inspection (IR 50-269,270,287/98-01), the NRC identified a weakness in NSD 208, Problem Investigation Process, Revision 16, where the procedure did not require LSE Category 3 PIPs to be reviewed for generic applicability. A similar finding was also identified during the HPI/LPI SITA. During this current inspection, the inspectors noted that PIP 0-098-0190 was initiated to address the SITA issue. The PIP indicated that procedure NSD 208 had been revised (subsequent to the completion of IR 50-269,270,287/98-01) to address this weakness. During review of Revision 17 to NSD 208, dated March 17, 1998, the inspectors noted that, although the revision to NSD 208 did not appear to include the corrective action guidance from PIP 0-098-0190 to allow the screening teams at the sites to identify and open the generic applicability section of LSE PIPs, software changes in the PIP computer data base had been made to allow the screening teams at the sites to open the generic applicability section of LSE PIP for the Operating Experience Assessment Section champions to perform a generic applicability review. The inspectors reviewed several LSE PIPs which had been reviewed for generic applicability. The inspectors considered the licensee's efforts to address this weakness to be a positive observation.

c. Conclusion

The inspectors concluded that the HPI/LPI SITA was a thorough and detailed effort that was effective in identifying equipment and programmatic issues. However, the licensee's documented evaluations were weak for some of the PIPs associated with findings from the HPI/LPI SITA. The PIPs were characterized by indeterminate problem evaluations, poor supporting documentation of conclusions, and screening the issues as low significance based on engineering judgement, which prevented operability determinations from being performed. The licensee's efforts to resolve a previously identified weakness regarding the review of LSE PIPs for generic applicability was noted as a positive observation.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) IFI 50-287/96-20-08: Integrated Control System (ICS) Post-Modification Testing

(Closed) IFI 50-287/97-01-04: Adequacy of Review Software Change

IFI 96-20-08 was originally opened to follow the ICS post modification testing on Units 1 and 2 after NRC questions about simulator modeling during ICS testing on Unit 3. IFI 97-01-04 was opened due to NRC concerns following inadvertent deletion of software which provided total feedwater flow indications to Unit 3 ICS control modules and further NRC questions about the simulator. These IFIs were discussed for Unit 1 in IR 50-269,270,287/98-02. ICS testing for Unit 1 was also discussed in IR 50-269,270,287/97-16.

The inspectors reviewed the modification test plan for Unit 2 NSM 22989,

ICS Replacement; reviewed PIP 3-097-0910 for the inadvertent software deletion; and discussed the test plan and the simulator modeling with ICS replacement personnel. The inspectors also reviewed the procedures, attended portions of the pre-job briefings, observed portions of the testing, and reviewed the data for the following Unit 2 ICS tests: ICS loss of power testing at 25 percent reactor power, electrical load rejection from 25 percent reactor power, main feedwater pump trip from 70 percent reactor power, maximum runback from 65 percent to 50 percent reactor power, and reactor coolant pump trip from 50 percent power.

The inspectors determined that the verification and validation simulator was only used before ICS testing on Unit 3. Lessons learned from that testing and from post-modification testing on Unit 3, were incorporated into the design and testing for Units 1 and 2. The inspectors determined that the problem evaluation and comments in PIP 3-097-0910 adequately addressed the inadvertent software deletion. The inspectors also found that the test procedures were adequately prepared to control the testing, collect data, deal with contingencies, and restore the unit to normal after testing. During the pre-job briefings the licensee gave a brief description of the testing, discussed the nuclear safety implications, discussed the roles and responsibilities of test and operations personnel, discussed management expectations for all participants, discussed contingencies, and gave opportunities for all participants to ask questions. The inspectors found the actual testing to be conducted in a well-controlled manner with good evaluation of results.

In addition to a new ICS, a new operator aid computer (OAC) was installed during the most recent outage on all three units. The inspectors observed licensee corrections to several minor and distracting problems with the system. Several middle managers assisted in identification of OAC and ICS problems during the return-to-service of Unit 2 prior to power operation. These individuals had been licensed operators. Two per shift were stationed at computer consoles in the rear of the control room. From there, they monitored operator control manipulation and system response. They identified and tracked problems with indications and alarms. This simple methodology greatly assisted in debugging the new system prior to its return to service.

Overall, the inspectors concluded the program used for post modification testing of the new integrated control system on Unit 2 was thorough and complete. The implementation of that program was well controlled with good evaluation of results. These items are closed.

IV. Plant Support Areas

R1 Radiological Protection and Chemistry Controls

R1.1 Chemistry Sampling and Radiological Controls

a. Inspection Scope (71750)

The inspectors observed local sampling activities, lab procedures, and interviewed chemistry personnel associated with the sampling requirements for LPSW radiation monitor RIA-35.

b. Observations and Findings

RIA-35, the LPSW process radiation monitor, was inoperable due to low flow conditions through the sample pump. The inspectors observed radiation protection (RP) personnel obtain samples from the Unit 3 LPSW system for analysis.

The samples observed were obtained within the 12 hour intervals as required. RP technicians carried a Marinelli container from the lab that had been premeasured for the 3500 milliliter sample. The inspectors observed the measurement of the Marinelli volume to verify the quantity. Operations personnel aligned the system for the local sample in accordance with the Procedure, OP/3/A/1104/10, Enclosure 3.4, Manual Sample of Points Monitored by RIA-35, Revision 3. The RP technician would then obtain the sample by opening the sample valve.

Three separate samples were observed. In only one did the RP technician flush the line before obtaining a sample. The distance from the valve to the sample point was approximately 4 inches (13 milliliter volume), which reduced the amount of stagnant water obtained with the sample. There was no procedure requirement for a flush or a volume to be flushed. Flushing of the sample line is a good analysis practice.

The sample was obtained and taken to the counting room. The RP personnel then ensured the outside of the Marinelli container was clean. The sample was then placed in a Germanium-Lithium detector to monitor for contamination. All samples observed indicated less than detectable levels above background. There is no requirement to monitor for contamination above background on samples that are presumed to be uncontaminated, such as LPSW.

c. Conclusions

The inspectors concluded that sample requirements for the out-of-service LPSW system radiation monitor were performed adequately.

R4 Staff Knowledge and Performance in RP&C

R4.1 Personnel Radiological Practices

a. Inspection Scope (71750)

During routing plant tours the inspectors observed the radiological practices of various workers, supervisors, and RP technicians.

b. Observations and Findings

On May 12, 1998, the inspectors observed a worker exit a contaminated area consisting of the 2B LPI pump room and associated stairway. As protective clothing the worker was wearing booties, shoe covers, cotton liners, and rubber gloves. The worker removed the shoe covers and stepped on to the step-off pad while still wearing the booties. The worker then removed the rubber gloves, booties, and cotton liners while standing on the step-off pad. When questioned, the worker admitted to being nervous while being watched by the NRC.

The inspectors discussed the observations with RP personnel and the workers management. The inspectors confirmed that the worker was appropriately dressed for the job but that transferring to the step-off pad without removing booties was not expected. The inspectors also learned that the worker had been primarily working in the RB where a double step-off pad allowed transferring to the first pad without removing booties.

The licensee has established a System Radiation Protection Manual in order to meet the requirements of 10 CFR Part 20 and the TS. The inspectors reviewed Procedure I-13, Use of Protective Clothing and Related Equipment, Revision 2, from this manual. Step 5.3 of this procedure described the process for removing protective clothing and instructed users to "Remove booties as you transfer to the step-off pad which is clean." The inspectors also reviewed NSD 507, Radiation Protection, Revision 1, which contained the same requirements for removing protective clothing in Section 507.8.4. The inspectors determined that the worker failed to follow Procedure I-13 and NSD 507 when removing protective clothing on May 12, 1998, and this constituted a violation of 10 CFR 20.1101(a). This is identified as VIO 50-269,270,287/98-06-10: Failure to Follow Radiation Protection Procedure.

Other RP practice violations were described in IR 50-269,270,287/97-12, 97-14, and 97-16. In those violations, inspectors identified: workers exiting a contaminated area without removing their booties; workers inside the radiological control area (RCA) without proper dosimetry; and a worker exiting the RCA without performing a survey for contamination. The licensee's corrective actions for those violations included counseling the workers on radiological practice and site-wide stop work sessions to emphasize the importance of proper radiological work practices. In this violation the worker failed to understand that the acceptable practice of transferring to the first step-off pad without removing booties when exiting the RB was not acceptable when leaving other contaminated areas.

c. Conclusions

The inspectors identified a violation for a worker exiting a contaminated area without properly removing protective clothing. This violation appeared to be caused by inadequate knowledge of protective clothing requirements on the part of the worker.

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (81700)

The inspectors reviewed licensee activities to determine whether the conduct of security and safeguards activities met the licensee's commitments in the NRC-approved physical security plan (PSP), applicable security procedures, and NRC regulatory requirements. The inspectors inspected the security program during May 10 to May 14, 1998. Areas inspected included the alarm stations, communications, and protected area access control of packages, personnel, and vehicles.

b. Observations and Findings

Alarm Stations

The inspectors observed excellent operation of the Central Alarm Station and the Secondary Alarm Station personnel and verified that the alarm stations were equipped with appropriate alarms, surveillance, and communications capabilities. Interviews with the alarm station operators found them knowledgeable of their duties and responsibilities. The inspectors also verified, through observations and interviews, that the alarm stations were continuously manned, independent, and diverse so that no single act could remove the plant's capability for detecting a threat or calling for assistance. In addition, the inspectors verified alarm station personnel did not have any other activities that could interfere with the execution of the detection, assessment, and response functions.

Communications

The inspectors verified, by document reviews and discussions with alarm station operators, that the alarm station personnel were capable of maintaining continuous intercommunications, communications with each security force member on duty, and were exercising communication methods with the local law enforcement agencies as committed to in the PSP.

Protected Area (PA) Access Control of Packages, Personnel, and Vehicles

The inspectors observed excellent package, personnel and vehicle search activities at the personnel and vehicle access portals. The inspectors determined, by observations, that positive controls were in place to ensure only authorized individuals issued picture badges were granted access to the PA and that all personnel and hand-carried items entering the PA were properly searched at the personnel access portal. During a review of PA access computer printouts, the inspectors noted that often

individuals were carded offsite several times without being carded onsite between each exit entry. Once, on April 22, 1998, an individual authorized PA access was carded exiting the PA; however, the individual was not entered into the access computer for being carded onsite. Review of Security Procedures 302, "Security Access Control and Alarm System Failure," dated 5/12/93, and 511, " Central and Secondary Alarm Station Operators," dated 10/26/95, and interviews with access control personnel revealed that this individual was not manually entered into the access computer following a period during which the computer was inoperable. Security personnel were required to list badges issued while the access computer was out of service. Then, when the computer was restored to service, these operators were required to enter the name and badge numbers into the computer. The cause of this event was the failure of an alarm station operator to enter an individual's name and badge into the computer, when it was restored to service. Two individuals with the same last name entered and exited the PA during the same time, causing confusion when personnel were entering names into the computer. Since the individual involved had PA access authorization and the incident had no safety significance, the inspectors considered the event as a minor procedural error. This failure constitutes a violation of minor significance and is not subject to formal enforcement action. This procedural error was discussed with the licensee for appropriate corrective action. The installation of the new badge and biometric access control system with redundant backup computers should prevent the repeat of this kind of incident.

The inspectors also observed positive personnel and vehicle controls at the vehicle access portal. Only after being properly searched were authorized individuals and vehicles granted access to the PA.

c. Conclusions

The licensee was conducting its security and safeguards activities in an excellent manner that protected public health and safety. This portion of the program, as implemented, met the licensee's commitments and NRC requirements.

S2 Status of Security Facilities and Equipment

a. Inspection Scope (81700)

Areas evaluated were testing and maintenance, PA detection aids, PA assessment aids, and compensatory measures.

b. Observations and Findings

Testing and Maintenance

The inspectors reviewed testing and maintenance records for security-related equipment and found that documentation was on file to prove that the licensee was maintaining and testing systems and equipment as committed to in the PSP and applicable security procedures. Work requests and repairs requiring compensatory measures were normally being

completed within the same day they were submitted. The inspectors observed a Seven-Day Test of the assessment and perimeter intrusion detection equipment during the back shift. All equipment tested functioned as required.

Compensatory Measures

The inspectors reviewed randomly selected Security Event Logs (SELs) and maintenance work requests which were generated over the last three years. These records indicated that the need for compensatory measures was minimal. At the time of the inspection, two compensatory measures were in place. One security force member was posted at the Unit 2 containment personnel hatch and was compensating for the vital area portal that was in an access mode. Closed Circuit Television (CCTV) camera number 7 could not be monitored at the Secondary Alarm Station so the Central Alarm Station was monitoring camera number 7 in the event there was a problem. The inspectors verified that appropriate security measures compensated for the inoperable equipment and consisted of the application of specific procedures to assure that the measures did not reduce the effectiveness of the security system.

PA Assessment Aids

The inspectors evaluated the effectiveness of the assessment aids, by observing on CCTV a security force member conducting a Seven-Day Test of 14 CCTV zones in the PA isolation perimeter zones. The assessment aids had good picture quality and excellent zone overlap. The inspectors verified that to ensure PSP commitments were satisfied, the licensee had procedures in place requiring the implementation of compensatory measures in the event the alarm station operator was unable to assess the cause of an alarm properly.

PA Detection Aids

The inspectors observed the Seven-Day test of 19 intrusion detection zones in the PA isolation perimeter zones. The zones tested could detect attempts to enter the intrusion detection system (microwave zone). The inspectors also observed the testing of the seismic cable intrusion detection system in the PA barrier. The inspectors, while reviewing SP 410, "Security CCTV," dated August 22, 1995, SP 401, "Intrusion Detection System," dated April 20, 1995, and SP 601, "Alarm Annunciation," dated September 11, 1995, determined that the licensee had established procedures to test the security equipment. The inspectors determined, by observations and by reviewing the testing documentation associated with the equipment repairs, that the repairs were made in a timely manner and that the equipment was functional and effective, and met the requirements of the PSP.

c. Conclusions

The licensee's security facilities and equipment were determined to be reliable and maintained in an excellent manner. The excellent maintenance support was the major factor to continued operability of the detection and assessment equipment.

S3 Security and Safeguards Procedures and Documentation

a. Inspection Scope (81700)

Applicable security procedures and randomly selected security event logs were reviewed to determine their adequacy and compliance with 10 CFR Part 50.

b. Observations and Findings

Security Procedures

The inspectors randomly reviewed 21 security procedures, and related supporting records and reports. The inspectors also interviewed security force personnel to decide their familiarity with the documents reviewed. The procedures reviewed pertained to Intrusion Detection Systems, Reporting of Safeguards Events, Compensatory Measures, Search Equipment, Access Controls, Alarm Stations, Communications, and Assessment Aids. The reviewed documents met 10 CFR 50.54(p)(1-3) requirements.

Security Event Logs

The inspectors reviewed five quarterly SELs from 3rd quarter 1995 to the 2nd quarter 1998, and related supporting records and reports. The inspectors also interviewed security force personnel to determine their familiarity with the events reviewed. The inspectors' evaluation verified that the licensee appropriately analyzed, tracked, resolved, and documented safeguards events that the licensee determined did not require a report to the NRC within one hour.

c. Conclusion

The licensee's SP documentation complied with 10 CFR Part 50 and Safeguards Event Logging/Reportability Program properly analyzed, tracked, resolved, and documented security incidences.

S8 Miscellaneous Security and Safeguards Issues

S8.1 (Closed) LER 50-269/98-S01: A Small Handgun Was Discovered During an Access Control Search of an Ingressing Licensee Employee.

The inspectors verified that the licensee investigated, documented and implemented corrective actions as described in PIP Form 4-098-0789. The responsive action of the security organization to prevent the

introduction of a firearm into the PA was excellent. No regulatory requirement was violated during the incident.

F1 Control of Fire Protection Activities

F1.1 Fire Reports and Investigations

a. Inspection Scope (64704)

The inspectors reviewed the plant fire incident reports and the resulting PIPs for 1997-98, to assess trends of maintenance related or material condition problems with plant systems and equipment that may initiate fire events. The inspectors verified that plant fire protection requirements were met in accordance with the facility document "Fire Protection Program," Revision 0, when fire related events occurred.

b. Observations and Findings

The fire incident related PIPs indicated that there were five incidents of smoke or fire within the plant in 1997, which required fire brigade response. Thus far in 1998, five fires had been reported in the plant. Of these, two were fires in safe-shutdown related plant areas that involved electrical equipment failures. In all cases, licensee personnel identified and extinguished the fire condition in a timely manner, contained the fire to the original source, and prevented the fire from spreading to other equipment or cables.

c. Conclusions

During 1998, there were two incidents of fire due to electrical equipment failures within safe-shutdown significant areas. In both cases, licensee personnel identified and extinguished the fire condition in a timely manner, contained the fire to the original source, and prevented the fire from spreading to other equipment or cables.

F1.2 Combustible Material Controls/Fire Hazards Reduction

a. Inspection Scope (64704)

The inspectors reviewed the licensee's administrative Nuclear System Directives, NSD 313, "Control of Combustibles and Flammable Material," Revision 1, NSD 116, "Nuclear Chemical Control Program," Revision 0, and NSD 104, "Housekeeping Materiel Condition, and Foreign Material Exclusion," Revision 13, to determine if they satisfied the combustible control and housekeeping objectives established by the licensee's approved fire protection program. The inspectors also toured selected plant areas to inspect the licensee's implementation of these procedures.

b. Observations and Findings

During plant walkdowns with the licensee's fire protection engineer and several members of the triennial fire protection audit team, the inspectors observed the following anomalies in the control of combustibles and housekeeping conditions in the Standby Shutdown Facility (SSF) diesel generator room, cable spreading rooms, and turbine building:

- Two unattended opened or unlatched fire resistive flammable liquids storage cabinets were noted in the SSF diesel generator room and on the turbine deck. The fire protection engineer immediately closed and latched the cabinets upon discovery.

- Three non-fire-retardant treated not-in-use pallets were stored on the turbine deck.

- Two non-fire-retardant treated wood pieces were left in cable trays in the Unit 1 cable spreading room.

- Five packaged combustible cardboard boxes containing piping insulation were stored in a scaffold staging area of the turbine building.

- Three examples were noted where work related transient combustible materials, tools and hand-held equipment, were left unattended in the plant turbine building, without housekeeping tags or with out-of-date tags.

In addition to the above anomalies, the triennial fire protection audit team noted other housekeeping and material condition problems. These issues were identified as a potential audit finding and reported to operations and maintenance management.

The inspectors concluded that the observed practices did not meet the intent of NRC fire protection guidance and licensee's procedures NSD 313, Section 313.3.3, and NSD 104, Section 104.5.1. The various plant departments were not consistently implementing their responsibilities for combustible material control. The observed level of plant housekeeping did not reflect good organization and cleanliness practices on the part of plant workers. The failure to follow fire protection program procedures for control of combustible materials and housekeeping is identified as VIO 50-269,270,287/98-06-11: Failure to Follow Procedure for Control of Combustible Material.

c. Conclusions

A violation of procedural requirements was identified for not using and correctly storing transient combustibles. The observed material condition in the plant indicated that the various plant departments were not consistently implementing their responsibilities for combustible material control. The observed level of plant housekeeping did not

reflect good organization and cleanliness practices on the part of plant workers.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Reportable Fire Protection Problem

a. Inspection Scope (71707, 37551)

On May 18, 1998, the licensee determined that penetration seals between the SSF shutdown components and normal plant shutdown components were not installed correctly. This condition had probably been in effect since the last work performed on the seals for all three units in 1988. The inspectors ensured that the licensee made appropriate notifications and had appropriate compensatory actions in place.

b. Observations and Findings

During a tri-annual fire protection audit exit of Duke General Office auditors, it was disclosed that inspection findings had revealed problems with the penetration seals between the East and West penetration rooms on Unit 1. The details of the findings are discussed in Section F7.1. Subsequently, on May 15, 1998, the licensee made a 10 CFR 50.72 report indicating degraded fire protection in Unit 1. The licensee had no reason to believe the fire protection for the seals on the other two units were not degraded. All units had been similarly worked in 1988. By tours on a sampling basis, the inspectors observed that fire watches were appropriately set and maintained from that May 15 evening forward on all three units. Later, the licensee confirmed that the poor quality seals existed on the other two units and the fire watches continued throughout the inspection period as repairs begun. Repairs were initiated on Unit 1. The licensee stated their intention to issue a LER on this topic. Section F7.1 of this report discusses NRC followup.

c. Conclusions

When it was determined that potential degraded fire protection existed, the licensee properly and promptly established compensatory action (i.e., fire watches were initiated in accordance with commitments).

The licensee was timely in recognizing the fire protection issue and made an appropriate notification to the NRC.

F2.2 Fire Pumps and Fire Protection Water Supply

a. Inspection Scope (64704)

The inspectors conducted a walkdown of the licensee's fire protection water supply system to verify that the system met the requirements described in UFSAR Section 9.5.1.5.2.

b. Observations and Findings

The inspectors observed that the fire protection water supply was provided by the high pressure service water (HPSW) system pumps. There were two 6,000 gpm HPSW pumps and one 500 gpm jockey fire pump, each rated at 117 pounds per square inch (psi) net pressure.

Section 9.5.1.5.2 of the Oconee UFSAR states that the HPSW pumps were located in separate concrete block fire rated structures. The inspectors verified that the redundant pumps were separated by fire walls and that the sliding fire doors for each room separating the pumps were operational and in their closed position. This assured that a fire within the Turbine Building would not damage both HPSW pumps. The inspectors noted that the maintenance and material condition of the fire pumps and their supporting equipment was good.

c. Conclusions

The general material condition of the fire pumps and the fire protection water supply was good. The physical separation of the redundant HPSW fire pumps was well maintained and met the criteria described in the UFSAR.

F2.3 RCP Oil Collection System

a. Inspection Scope (64704)

The inspectors reviewed the design and maintenance of the oil collection system for the reactor coolant pumps to verify that the requirements of UFSAR Section 9.5.1.6.1 and 10 CFR 50 Appendix R, Section III.O were met.

b. Observations and Findings

The inspectors reviewed UFSAR Section 9.5.1.6.1, Plant Design Basis Specification for Fire Protection, OSS-0254.00-00-00-4008, RCP oil collection system flow diagram drawing Nos. OFD-100-2.4, Revision 14, maintenance procedures MP/0/B/3009/009 and 9A, "Reactor Coolant Pump-Minor Preventative Maintenance,"Revision 8, and other related documentation.

The inspectors reviewed the procedures and interviewed the system engineers and concluded that sufficient procedural guidance was provided to verify that the RCP oil collection tanks were normally maintained empty and that the plant operators could identify an oil leak from the lubrication system of any one of the RCP motors and take appropriate action. This met the performance criteria of 10 CFR 50 Appendix R Section III.O.

c. Conclusions

Sufficient procedural guidance was provided to verify that the RCP oil collection tanks were normally maintained empty and that the plant

operators could identify an oil leak from the lubrication system of any one of the RCP motors and take appropriate action. The RCP oil collection system met the performance criteria of 10 CFR 50 Appendix R Section III.O.

F2.4 Operability of Fire Protection Facilities and Equipment

a. Inspection Scope (64704)

The inspectors reviewed the impairment log for the time period of November 18, 1997 to May 13, 1998, for fire protection components and features to assess the licensee's performance for returning degraded fire protection components to service.

b. Observations and Findings

As of May 13, 1998, there were only nine fire protection components listed on the impairment log as degraded. Seven of the nine impairments involved breached penetration seals. Discussions with the facility fire protection staff indicated that these breached penetration seals were due to cable pull activities associated with ongoing security system modifications.

The inspectors reviewed previous impairments listed in the fire protection impairment log and noted that of the 205 impairments listed for the time period, nearly 171 involved breached penetration seals. The high number of penetration seal breaches was due to cable pull activities associated with the security system modifications. The inspectors determined 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.

c. Conclusion

The low number of inoperable or degraded fire protection components indicated that appropriate emphasis had been placed on the maintenance and operability of the fire protection equipment and components. Impaired fire protection components had been restored to service in a timely manner.

F3 Fire Protection Procedures and Documentation

F3.1 Surveillance Procedures for Hose Stations and Standpipes

a. Inspection Scope (64704)

The inspectors reviewed the design and surveillance tests for the standpipe and hose system to determine compliance with UFSAR Section 9.5.1.5.3, "Water Sprinklers and Hose Standpipe Systems," and UFSAR Section 16, Selected Licensee Commitments (SLC), Item 16.9.4, "Fire Hose Stations."

b. Observations and Findings

The inspectors selected the inspection and surveillance requirements from the UFSAR Section 16, SLC Item 16.9.4, for the HPSW standpipe and hose station system to verify that the performance criteria for the fire protection components that provide this function had been incorporated into the appropriate surveillance procedures. A review of design calculation OSC-1626, "Auxiliary Building Hose Station Pressure," Revision 3, maintenance procedure MP/0/A/1705/32, "Fire Protection Equipment Inspection," Revision 9, and periodic test procedure PT/0/A/250/24, "Fire Protection System Three Year Flow Test, "Revision 15, and discussions with the facility fire protection engineer revealed that the scope and content of the maintenance inspection and periodic test procedures were sufficient to perform verification that the fire hose station placement, water flow and water pressure requirements established in UFSAR Section 9.5.1.5.3 were met.

c. Conclusions

The scope and content of the maintenance inspection and surveillance test program procedures for the fire protection hose stations and standpipes were sufficient to assure that the fire protection design and surveillance requirements specified in the UFSAR were met.

F5 Fire Protection Staff Training and Qualification

F5.1 Fire Brigade Organization and Drills

a. Inspection Scope (64704)

The inspectors reviewed the fire brigade organization and drill program for compliance with plant procedures and the approved fire protection program as described in UFSAR Section 9.5.1.3.

b. Observations and Findings

The inspectors verified that the organization and drill requirements for the plant fire brigade were established by OSS-0254.00-00-00-4008, "Plant Design Basis Specification for Fire Protection," Revision 2, and NSD 112, "Fire Brigade Organization, Training and Responsibilities," Revision 0.

Due to Unit 2 being shutdown and the high priority work in process, a fire brigade drill was not observed during this inspection period. To evaluate drill performance, the inspectors reviewed the drill evaluation data for the shift drills conducted for the third and fourth quarters of 1997 and first quarter of 1998, and verified that the fire brigade response and participation for these drills satisfied the requirements of the site procedures.

c. Conclusions

The fire brigade organization and drill program met the requirements of the site procedures. The performance by the fire brigade as documented by the licensee's drill evaluations was good.

F7 Quality Assurance in Fire Protection Activities

F7.1 Fire Protection Audit Reports (64704)

a. Inspection Scope

The inspectors observed portions of a Triennial Fire Protection Audit, SA-98-100(ALL)(RA), which was conducted May 11-15, 1998.

b. Observations and Findings

The Quality Assurance (QA) organization performed an evaluation of the fire protection program during the time period of May 11-15, 1998. This audit included an oversight assessment of the fire protection program as applied to fire protection systems, fire barrier penetration seal program, fire loading, fire protection equipment, maintenance and surveillance procedures, training and qualification, transient combustible controls, plant modifications, operability of the SSF and emergency lighting.

UFSAR Section 16, SLC Item 16.9.5, "Fire Barrier," states that all fire barriers (including mechanical and electrical penetrations...) boundaries, as shown on the 0-310-K and 0-310-L series drawings shall be operable. During this inspection period, the inspectors, in conjunction with an ongoing Triennial Fire Protection Audit team, observed the foam installation of three silicone type cable tray fire barrier penetration seals (1-M-N-3, 1-M-S-8, and 1-K-E-9) which had their damming boards removed. The silicone foam type penetration seals were normally covered by the 1-inch thick ceraform damming boards. Inspection of the penetration seals identified a number of significant discrepancies associated with the seals, such as voids in the silicone foam, cracked or missing damming boards, and voids between cables that maintain the fire boundary characteristics of the seal assembly. The licensee initiated PIP 2-098-2571 to address the audit team's potential finding identified to the licensee management in this area. The inspectors verified that the affected seals were placed under a fire watch patrol as required by SLC 16.9.5.

The licensee's initial review was unable to determine whether the specifications and implementing procedures for the installation, maintenance, repair, and inspection of penetration seals were in conformance with the silicone foam seal vendor requirements. The licensee stated that inspections of additional penetration seals and review of this issue would be required to establish the extent and the cause of the identified silicone foam seal installation problems.

Pending further review by the licensee to determine the extent and the cause of identified silicone foam seal installation problems and subsequent review by the NRC, this issue will be identified as URI 50-269,270,287/98-06-12: Determine If The Installation, Maintenance, Repair, and Inspection of Penetration Seals Are In Conformance With Vendor Requirements.

The inspectors noted that the audit team identified eight potential significant findings. These findings are under review for resolution by the licensee. The audit team also identified six less significant recommendations. The inspectors concluded that the 1998 Triennial Fire Protection Audit of the facility's fire protection program was comprehensive and effective in identifying fire protection program performance to the plant management.

c. Conclusions

An Unresolved Item was identified regarding the licensee's installation, maintenance, repair, and inspection of penetration seals. The 1998 Triennial Fire Protection Audit of the facility's fire protection program was comprehensive and effective in identifying fire protection program performance to plant management.

F8 Miscellaneous Fire Protection Issues

F8.1 (Open) IFI 50-269,270,287/97-15-07: Review of Licensee's Revalidation of Fire Barrier Penetration Seals

The licensee had started a project to revalidate the installation of penetration seals. The project would determine if each penetration was bounded by a specific design specification and if the penetration seal was substantiated by qualified test documents. The fire barrier penetration seals for each unit were scheduled to be revaluated 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).

Based on this additional information, this item will remain open.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 18, 1998. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

X2 Notice of Enforcement Discretion on Steam Generator Tube End Anomaly (TEA)

a. Inspection Scope (37551,62707)

The text of PIP 7-098-2458, discussed a re-review of Unit 2 SG tube eddy current data that indicated some TEA inspection findings were reclassified as repairable indications. Prior to the Unit 2 return from refueling, these reclassified TEA indications were repaired. The licensee re-reviewed data from the last Unit 1 and 3 inspections to determine if TEAs existed that should be reclassified. The NRC followed the licensee actions.

b. Observations and Findings

An issue was identified at another facility involving TEA indications. Duke Energy personnel requested the Arkansas information that included actual eddy current data tapes of the affected tubes. The information was received on or about April 20, 1998. The licensee reviewed the information for applicability on Unit 2, which was in a refueling outage at the time with its steam generators open for inspection. The review found some steam generator tube eddy current data done to date that indicated some TEAs should be reclassified as repairable indications. PIP 7-098-2458 was written May 6, 1998. Potentially repairable indications were found in the pressure boundary roll areas in the a number of tubes at the upper tube sheet. The licensee stated that, until receipt of the Arkansas information, their inspection procedures had been weak in the area of tube end inspection criteria. During the refueling outage, the Unit 2 reclassified TEA indications were repaired. Understanding the potential impact, the licensee performed an immediate current operability determination for the two other Oconee units. This operability assumed that such indications existed on those units. On May 9, via an evaluation in the PIP, the licensee determined that the hypothetical worst case indications were acceptable based on: (1) a tube burst at a upper tube sheet end location would be captured by the reinforcing tube sheet; and (2) that during a worst case scenario leakage due to described tube end problems would be less than off site dose analysis limits. The licensee indicated that the tubes in the others units were acceptable based on the above evaluation. Further, they indicated that they would perform actual eddy current data re-review from the last Unit 1 and Unit 3 refueling steam generator tube inspections to determine the number and type, if any, of indications that may require repair or lay outside their worst case May 9 evaluation. Additionally, they were to have a vendor perform mockup checks on TEA detectability in the two types of tube end configurations found at Oconee.

On June 2, 1998, the licensee had completed their re-review. A number of indications on both units were reclassified as requiring repair that had not been performed at the last units' tube inspections. When briefly discussed with NRR on that date, the NRC indicated that those findings did not conform to TS 4.17.2 requirements and were possible grounds for a request for enforcement discretion. The licensee entered

a 24-hour grace period they thought was allowed by their TS for a missed surveillance at 5:51 p.m. on June 2. Subsequently, on June 3, they requested a NOED at 9:00 a.m. The evaluation for the Unit 1 and Unit 3 indications was still within the initial evaluation discussed above. The licensee had compensatory measure in place as indicated in their request. Both units met the steam line break leakage requirements for steam generator integrity and are capable of performing their intended safety function during normal operations and postulated accident conditions. The licensee was to request a exigent TS amendment to permit operation with unrepaired/unplugged steam generator tubes with TEAs which potentially meet the defect criterion as defined in TS 4.17.5.e on June 4. Based on this information, and the determination that the action involved minimal or no safety impact and has no adverse radiological impact on public health and safety, the NOED was granted verbally at 12:25 p.m., on June 3. The licensee submitted a written request for the NOED the same day, which was NRC approved by letter dated June 4, NOED No. 98-6-008. The NOED indicates that the NRC will not enforce compliance with the TS for steam generator tubes in Unit 1 and 3 with TEAs until the amendment with similar requirements is approved. The licensee submitted the exigent TS change request on June 4.

On June 3, the NRC verbally indicated, and later re-stated in the NOED approval letter, that the NRC did not believe that the need for the NOED was generated by a missed surveillance. The NRC staff believed that this NOED should have been requested in response to a potential TS noncompliance.

The licensee is to issue a LER on this topic and its review by the NRC will determine possible additional enforcement actions. This issue will be tracked by a URI 50-269,287/98-06-13: Potential Steam Generator TS Issues.

c. Conclusions

The licensee discovered information about steam generator tube inspection activities from an outside source. The licensee factored this emergent operational data into their on-going Unit 2 generator inspection.

The evaluation of the operational data on Unit 2 steam generator tube inspections revealed a weakness in the licensee inspection program.

The immediate evaluation of the steam generator tube end anomaly problem revealed there was no safety impact. Subsequent review of actual tube inspection data on Units 1 and 3 based on updated inspection criteria, revealed that Surveillance Requirement 4.17.2 had not been completed.

A NOED was issued to allow continued operation of Units 1 and 3 until an appropriate Technical Specification amendment is approved. A unresolved item was identified to followup collateral issues around the discretion.

The request for NOED on the steam generator tube indication problem and

the submitted technical specification change request were technically complete.

X3 Pre-Decisional Enforcement Conference Summary

On May 19, 1998, a predecisional enforcement conference was held in the Regional Office with the licensee to discuss apparent violations (EEI) 50-269,270/98-03-04 and EEI 50-269,270/98-03-05, covered by EA Case No. 98-199. Following the conference, a Notice of Violation (NOV) was issued to the licensee on June 5, 1998, for apparent violation EEI 50-269,270/98-03-04. The violation cited in the NOV will be tracked as EA 98-199-01014, USQ Involving Single Failure Vulnerability Introduced by a 1984 CRVS Modification. The violation was characterized as a Severity Level IV problem. The second apparent violation EEI 50-269,270/98-03-05 regarding a 1997 untimely update to the FSAR for the 1984 modification to the CRVS was determined to be a Non-Cited Violation (NCV) consistent with Section VII.B.1 of the NRC Enforcement Policy. This item will be identified and tracked as NCV 98-199-02014, Untimely FSAR Change for 1984 CRVS Modification. Based on the above, both EEIs are now considered closed.

Partial List of Persons Contacted

Licensee

L. Azzerello, Mechanical Systems Engineering Manager
D. Brandes, Consultant Engineer, Nuclear Engineering
E. Burchfield, Regulatory Compliance Manager
T. Coutu, Nuclear Section Manager, Valves
T. Curtis, Operations Superintendent
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
T. King, Security Manager
C. Little, Electrical Systems/Equipment Engineering Manager
H. Lefkowitz, Fire Protection Engineer
R. Matheson, Corrective Action Program Lead, Oconee Safety Review Group
W. McCollum, Vice President, Oconee Site
B. Medlin, Maintenance Superintendent
M. Nazar, Manager of Engineering
M. Satterfield, Security Support Supervisor
T. Saville, Supervisor, Primary Systems
J. Smith, Regulatory Compliance
J. Twiggs, Manager, Radiation Protection

Other licensee employees contacted during the inspection included technicians, maintenance personnel, and administrative personnel.

NRC

D. LaBarge, Project Manager

Inspection Procedures Used

IP37551	Onsite Engineering
IP37828	Installation and Testing of Modifications
IP40500	Effectiveness of Licensee Controls In Identifying and Preventing Problems
IP61726	Surveillance Observations
IP62707	Maintenance Observations
IP64704	Fire Protection Program
IP71707	Plant Operations
IP71750	Plant Support Activities
IP81700	Physical Security Program for Power Reactors
IP92700	Onsite Followup of Written Event Reports
IP92901	Followup - Plant Operations
IP92902	Followup - Maintenance
IP92903	Followup - Engineering
IP92904	Followup - Plant Support
IP93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-269,270,287/98-06-01	VIO	Lack of Procedure for Adjusting RCP Restraints (Section O1.4)
50-269,270,287/98-06-02	NCV	Failure to Properly Implement Surveillance Requirements (Section O8.1)
50-270,287/98-06-03	URI	Unit 2 and 3 RC Makeup Pump Past Operability (Section O1.5)
50-269,270,287/98-06-04	URI	Unit 2 Valve Misposition Issues (Section O2.3)
50-270/98-06-05	URI	2LWD-444 Mispositioning May Affect Penetration Room Ventilation (Section O2.4)
50-269/98-06-06	VIO	Failure to Follow Procedure During ES Testing (Section O4.2)
50-269,270/98-06-07	URI	LPSW Pump Bearing Failures (Section M2.1)
50-270/98-06-08	VIO	Failure to Complete Procedure Following SSW Modification (Section M3.1)
50-270/98-06-09	VIO	Failure to Perform Safety Evaluation (Section E3.1)
50-269,270,287/98-06-10	VIO	Failure to Follow Radiation Protection Procedure (Section R4.1)
50-269,270,287/98-06-11	VIO	Failure to Follow Procedure for Control of Combustible Material (Section F1.2)
50-269,270,287/98-06-12	URI	Determine If The Installation, Maintenance, Repair, and Inspection of Penetration Seals Are In Conformance With Vendor Requirements (Section F7.1)
50-269,287/98-06-13	URI	Potential Steam Generator TS Issues (Section X2)
EA 98-199-01014	VIO	USQ Involving Single Failure Vulnerability Introduced by a 1984 CRVS Modification (Section X3)
EA 98-199-02014	NCV	Untimely FSAR Change for 1984 CRVS Modification (Section X3)

Closed

50-269,270,287/97-18-12	URI	Refueling Outage Surveillance (NOED for Units 2 and 3) (Section O8.1)
50-269,270,287/97-02-03	VIO	Failure to Perform Procedure Prerequisites (Section M8.1)
50-269,270,287/97-05-03	VIO	Failure to Provide Adequate Corrective Actions (Section M8.2)
50-287/96-20-08	IFI	Integrated Control System Post-Modification Testing (Section E8.1)
50-287/97-01-04	IFI	Adequacy of Review Software Change (Section E8.1)
50-269/98-S01	LER	A Small Handgun Discovered During an Access Control Search of an Ingressing Licensee Employee (Section S8)
50-269,270/98-03-04	EEI	USQ Involving Single Failure Vulnerability Introduced By 1984 CRVS Modification (Section X3)
50-269,270/98-03-05	EEI	Untimely FSAR Change for 1984 CRVS Modification (Section X3)
50-269/98-03	LER	Missed Surveillance Due to Non-Literal Interpretation of Technical Specifications (Section O8.1)

Discussed

50-269,270,287/97-15-07	IFI	Review of Licensee's Revalidation of Fire Barrier Penetration Seals (Section F8.1).

List of Acronyms

ASME	American Society of Mechanical Engineers
BWST	Borated Water Storage Tank
CCTV	Closed Circuit Television
CCW	Condenser Circulating Water
CFR	Code of Federal Regulations
COLR	Core Operating Limits
CRDM	Control Rod Drive Mechanism
EEI	Apparent Violation
EOP	Emergency Operating Procedure
ES	Engineered Safeguards
ESV	Essential Siphon Vacuum
EWST	Elevated Water Storage Tank
F	Fahrenheit
FIP	Failure Investigation process

GPM	Gallons Per Minute
HPI	High Pressure Injection
ICS	Integrated Control System
I&E	Instrument & Electrical
IFI	Inspector Followup Item
IR	Inspection Report
KV	KiloVolt
LDST	Letdown Storage Tank
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
LSE	Less Significant Event
MSE	More Significant Event
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NOED	Notice of Enforcement Discretion
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSD	Nuclear System Directive
NSM	Nuclear Station Modification
ONS	Oconee Nuclear Station
PA	Protected Area
PDR	Public Document Room
PFP	Percent of Full Power
PIP	Problem Investigation Process
PSI	Per Square Inch
PSIG	Pounds Per Square Inch Gauge
PSP	Physical Security Plan
PT	Penetrant Testing
QA	Quality Assurance
QPT	Quadrant Power Tilt
RB	Reactor Building
RBES	Reactor Building Emergency Sump
RC	Reactor Coolant
RCA	Radiological Control Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REV	Revision
RO	Reactor Operator
RP	Radiation Protection
RT	Radiography Testing
SAR	Safety Analysis Report
SELs	Security Event Logs
SFM	Security Force Member
SFP	Spent Fuel Pool
SG	Steam Generator
SITA	Self Initiated Technical Audit
SRO	Senior Reactor Operator
SSF	Standby Shutdown Facility
SSW	Siphon Seal Water
TDEFW	Turbine Driven Emergency Feedwater

TEA	Tube End Anomaly
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
WO	Work Order