U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	November 29, 1998 - January 16, 1999
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/98-11,
50-270/98-11, and 50-287/98-11

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

Operations

- The overall Unit 3 startup following the end-of-cycle 17 refueling outage was performed by operations personnel with proper command and control, control room communications, shift turnover activities, and use of appropriate procedures. (Section O1.2; [POS: 1A, 3A, 3B - Adequate])

- Following a Unit 3 reactor trip, operators properly followed their procedures and exhibited good command and control. (Section O1.3; [POS: 1B, 3A, 3B - Good])

- Operations personnel properly initiated a procedure change and properly adhered to it when isolating feedwater startup control valve 3FDW-35. (Section O1.4; [POS: 1A, 3A - Good])

- With the operators exhibiting good command and control, Unit 1 was reduced from 100 to 20 percent power to add oil to reactor coolant pumps 1A2 and 1B1 motors. Minor problems during the return to power were handled well. (Section O1.6; [POS: 1A, 3A - Good])

- The inspectors concluded that the licensee's reactor building tour conducted at hot shutdown prior to Unit 3 startup was thorough and detailed, with minimal discrepancies found. This was continuing indication that corrective actions dealing with material conditions in the reactor building have been effective in reducing potential operational risk **(Recovery Plan SE1)**. (Section O2.4; [POS: 2A, 2B, - Good])

- The daily risk assessment process met the goals of the recovery plan. Specific actions of the process had either been implemented or scheduled **(Recovery Plan Item OF4 - closed)**. (Section O2.5; [POS: 2B - Adequate])

- The inspectors concluded that operations' failure to identify that the Unit 3 loop vent performance test had not been completed was a weakness in the review of startup prerequisites and in operations procedures. The work control personnel's removal of the performance test from the schedule without the test being completed was also a weakness. (Section O4.1; [WEAK: 1A, 3A, 3C - Poor])

- General inspection period findings found human performance errors still occurring; some of which were process problems that will require longer term resolutions. There were several surveillance performance issues in this period **(Recovery Plan P1)**. (Section O4.2; [NEG: 3A, 3B, 3C - Poor])

- The licensee was reporting findings as required to the NRC. (Section O4.2; POS:1A, 5B - Adequate])

- The inspectors concluded that the licensee's implementation of the mispositioning root cause assessment initiative (N9740) was not adequate to close Recovery Plan Item OF1 **(Recovery Plan Item OF1)**. (Section O7.1; [NEG: 1C, 3C, 5C - Poor])

- The inspectors concluded that the demonstrated deficiencies in the documentation and understanding of overtime requirements warrants further NRC inspection and resulted in an unresolved item. (Section O7.2; [URI: 1C, 3C, 5A - Poor])

- The simultaneous testing of an engineered safeguards channel and emergency power system components resulted in the recurrence of a previous problem when an engineered safeguards component unexpectedly actuated during testing of an engineered safeguards channel and a Keowee hydro electric unit. This was another example of a previously cited violation. (Section O8.1; [NEG: 5B, 5C - Poor])

- The root cause evaluation and corrective actions taken following loss of onsite emergency electrical power during testing were proper for the situation. (Section O8.2; [POS: 5B, 5C - Adequate])

- Failure to follow procedure when stopping a Keowee hydro electric unit following testing caused damage to two Keowee circuit breakers and resulted in a non-cited violation. (Section O8.2; [NCV: 1A, 3A - Poor])

Maintenance

- The general cold weather preparations for electrical trace and electrical space heating systems were comprehensive, identified the electrical heating equipment required by the program, and gave instructions on adjusting the heating control equipment. The controlling procedure for cold weather electrical heating protection and the work activities were good. (Section M1.2; [POS: 1C, 2B - Good])

- Weaknesses were identified in the cold weather preparation program. The area heaters in the plant steam heating system were not tested prior to the onset of cold weather. Turbine building louvers were not verified as closed prior to cold weather. (Section M1.2; [WEAK: 1C, 2B, 3C - Poor])

- The material condition of the plant heating system was considered poor after testing identified 8 out of 29 heaters as inoperable with the majority in one area of the Unit 3 turbine building basement. (Section M1.2; [WEAK: 2A, 2B - Poor])

- Mechanical and instrumentation trouble shooting procedures met the intent of the Recovery Plan. With one exception, the procedures were implemented properly. Recovery Plan Item TD5 remains open **(Recovery Plan Item TD5).** (Section M1.3; [POS: 2B - Adequate])

- The licensee has made large strides in improving general plant conditions by implementing and carrying out a material condition upgrade and repair effort. Further repairs and upgrades have been discussed, but the licensee has yet to produce a scope definition or schedule of future repairs **(Recovery Plan Item SE1)**. (Section M1.4; [POS: 2A, 2B - Good])

- The testing specified by the inservice testing program was generally consistent with the applicable regulatory requirements with the exception where an apparent violation identified involving inadequate stroke timing of motor-operated valves. This apparent

violation will remain open for a reasonable time to allow the licensee to develop corrective actions. (Section M3.1; [EEI: 2B - Poor])

- The proper valves had been selected for the inservice testing program and justifications for test deferrals were acceptable. (Section M3.2; [POS: 2B - Adequate])

- A non-cited violation was identified for an earlier failure to have quality control verification of safety-related Keowee work involving transformer tap position alterations. (Section M8.1; [NCV: 3A - Poor; POS: 5A, 5C])

Engineering

- Poor engineering judgement was shown in that a temporary power installation from the essential siphon system building received an engineering review without a specified routing path. The temporary power was tied into a motor control center that also supplies power to systems important to safety. (Section E2.1; [WEAK: 3A, 4B - Poor])

- Dismantling of a vent louver on the essential siphon vacuum building for the power path, required to be closed during cold weather, was not detected by installers or building users as a configuration control problem on support systems important to safety. This was considered a weakness. (Section E2.1; [WEAK: 2A, 3A, 3B - Poor])

- A wiring error and inadequate testing during the installation of non-safety-related temperature indication for the Unit 3 essential siphon vacuum system float valves gave the operators a false temperature indication and caused Unit 2 and 3 to be placed in an unnecessary limiting condition for operation. Similarly, two thermostats on two condenser circulating water pumps' support equipment instrumentation were not properly installed, calibrated, or tested. (Section E2.1; [WEAK: 3A, 4B - Poor])

- The survey and analysis of the historical outside temperature data and using the information to develop freeze protection requirements for the essential siphon vacuum system was good. (Section E2.1; [POS: 3A, 4A, 4B - Good])

- The same type of analysis was applied to verify the adequacy of existing freeze protection equipment used at Oconee. (Section E2.1; [POS: 3A, 4B - Adequate])

- The Keowee Emergency Power and Engineered Safeguards test was performed well with the test meeting acceptance criteria. (Section E2.2; [POS: 2B, 3A, 4B - Good])

- As corrective action for a potential essential siphon vacuum failure scenario, the licensee took prompt corrective action to realign the system and change applicable procedures. (Section E2.3; [POS: 5B, 5C - Adequate])

- Three examples of an apparent violation of 10 CFR 50, Appendix B, Criterion XVI were identified [two examples for untimely corrective actions related to the resolution of problem investigation process reports and one example where the corrective actions were inadequate for a previously identified violation]. This apparent violation will remain open for a reasonable time to allow the licensee to develop corrective actions **(Recovery Plan Item SA1).** (Section E2.4; [EEI: 4B,5C - Poor]) (Section E8.2; [EEI: 4B,5C - Poor])

- The Problem Investigation Process (PIP) report backlog categorized as Management Exceptions was not included in the licensee's scope, schedule, and goals for implementation of Recovery Plan Item SA1: Corrective Action PIP Activity Backlog. The

inspectors concluded that implementation of the Management Exception backlog was not adequate because the criteria for Management Exception items did not consider priority based on the significance of the problem or technical justification as demonstrated by the untimely resolution of the PIPs reviewed during this inspection **(Recovery Plan Item SA1).** (Section E2.4; [NEG: 4B,5C - Poor])

- The licensee's implementation of the high pressure injection (HPI)/low pressure injection Self-Initiated Technical Audit System Review, which was the second phase of the HPI System Review initiative, was consistent with the scope and goals described in the Recovery Plan. Although all of the original corrective actions were not completed by the December 31, 1998, target date, the remaining items had action plans and were scheduled for completion **(Recovery Plan Item DB2 - closed).** (Section E2.5; [POS: 4B,5C - Good])

- The licensee's implementation of the Configuration Management initiative was not consistent with the scope, schedule, and goals described in the Recovery Plan. All of the near term corrective actions defined in Revision 2 of the Configuration Management Improvement Team charter were not completed by the November 1, 1998, date specified in the charter. Also, some of the interim measures previously implemented to prevent Engineering configuration management issues had been discontinued **(Recovery Plan Item DB10).** (Section E2.6; [NEG: 4A,4C,5C - Poor])

- The licensee was resolving through the Problem Investigation Process and the Failure Investigation Process (FIP) all the potential problems brought to light by conducting a special test on Keowee in November 1998. The most significant problem was the chattering with one phase failing to close on one of the nine contractor that were monitored during the test. The FIP team had found the most probable cause to be a weak contractor coil. However, this finding was preliminary and more work was needed to confirm the cause. (Section E2.7; [POS: 5B - Good])

- The licensee's implementation of the Problem Investigation Process Quality Improvements (Root Cause Quality) initiative was not consistent with the scope, schedule, and goals described in the Plan. No feedback or mechanism for feedback was provided from the 16 point root cause quality check to the root cause evaluators as described in the Root Cause Improvement Plan. Performance goals described in the Plan were not met **(Recovery Plan Item SA2).** (Section E7.1; [NEG: 5C - Poor])

- The licensee's implementation of the Manager Observation/Group Assessment Effectiveness and Benchmarking was, in general, consistent with the scope, schedule, and goals described in the Oconee Recovery Plan. Although the number and percentage of manager observations and group self-assessments met the Recovery Plan goals, efforts to improve the quality were on-going. Revisions to Nuclear System Directive NSD-607 to address some of the weaknesses identified by the licensee are scheduled to be implemented in early 1999 **(Recovery Plan Item SA3).** (Section E7.2; [POS: 5A - Adequate])

- The licensee's implementation of the In-plant Review/Safety Review Group (SRG) Job Observation Program initiative as implemented through the Independent Nuclear Oversight Team, was consistent with the scope and goals described in the Oconee Recovery Plan. Although all items were not completed as specified in the Plan schedule, the SRG was achieving the Plan's intended functions of independent in-plant reviews and reporting station health to management **(Recovery Plan Item SA4 - closed).** (Section E7.3; [POS: 5A - Adequate])

- The licensee's actions to resolve the self-identified equipment performance deficiency related to K-Line Breaker Issues (Inspector Followup Item 50-269,270,287/97-18-06) were good. (Section E8.3; [POS: 4B, 5C - Good])

- The licensee's actions to resolve Violation 50-269,270,287/98-03-02; Licensee Event Report 50-269/98-10; and NOED 98-6-011 were considered adequate. (Section E8.4; [POS: 5C - Adequate])

- A non-cited violation was identified for incorrectly placing an individual on the Qualified Reviewers List without the individual having completed the required training. (Section E8.6; [NCV: 4C - Poor; POS: 5A, 5C - Good])

- The licensee's corrective actions to address NRC violation 50-269,270,287/98-05-01 were adequate. (Section E8.7; [POS: 4B,5C - Adequate])

- The licensee was adequately addressing the inservice test program and design control process interface problems that had been identified through the licensee's self-initiated technical audit, which resolved associated Unresolved Item 50-269,270,287/98-07-04. (Section E8.8; [POS: 5B - Adequate])

- The analysis and resolution for Licensee Event Report 50-269/97-10 was considered good. (Section E8.9; [POS: 5B, 5C - Good])

- The analysis and resolution for Violation 50-269,270,287/97-16-03 was considered good. (Section E8.10; [POS: 5 B, 5C - Good])

Plant Support

- On December 15, 1998, the licensee conducted what it designated as "1998 Emergency Response Exercise II" as an integrated quarterly drill with participation by the Control Room Simulator, Operational Support Center, Technical Support Center, and Emergency Operations Facility. An integral aspect of the scenario objectives was to demonstrate corrective action with respect to the two exercise weaknesses identified during the August 18, 1998, full-participation exercise. The inspectors noted significant improvements in the performance of the emergency response organization and suitable corrective action for the two exercise weaknesses. (Section P4.1; [POS:1C, 5C - Good])

- The licensee demonstrated effective corrective action with respect to previously identified weaknesses by conducting a drill which demonstrated timely followup of damage assessment reports and prompt classification of the General Emergency. (Section P8.1; [POS: 5C - Good])

- The licensee's security plan changes were thorough, well documented, and consistent with the Physical Security Plan commitments and 10 CFR Part 50. (Section S3.1; [POS: 1C, 3C - Good])

- The licensee's actions to implement NRC Information Notice 98-35, "Threat Assessments and Consideration of Heightened Physical Protection Measures," dated September 4, 1998, were considered adequate. (Section S4.2; [POS: 1C, 3C - Good])

- Corporate, site and security management were very effective in providing support to the Physical Security Program. This was a major strength in the Duke nuclear security program. (Section S6.2; [STREN: 1C, 3C - Excellent])

- The licensee reviewed and analyzed documented problems, reached logical conclusions, and prioritized the problems for appropriate corrective action. This problem analysis program was a major strength to the security program. (Section S7.2; [STREN: 5B - Excellent])

- The licensee's corrective actions for security related problems were technically sound, effective, and performed in a timely manner. (Section S7.3; [POS: 5C - Adequate])

- The licensee's management controls of the security program were aggressive, effective, and comprehensive. (Section S7.4; [POS: 1C, 3C - Good])

- A non-cited violation was identified for a safeguards information document being unsecured and unattended. (Section S8.3; [NCV: 3A, 3B - Poor; POS: 5A, 5C - Adequate])

- The licensee took appropriate corrective actions when informed that a contract employee failed to report criminal offenses on pre-employment screening records. (Section S8.4; [POS: 5C - Good])

- A violation of procedural requirements was identified for not properly implementing continuous fire watch requirements. A designated continuous fire watch left the affected turbine building continuous fire area unattended for longer than 15 minutes. (Section F1.1; [VIO: 1C, 3A - Poor])

- One non-cited violation was identified for failure to maintain a required three-hour penetration seal fire barrier rating. (Section F8.4; [NCV: 1C, 2A - Poor; POS: 5A, 5C - Good])

- Corrective actions were found to be good for two violations which involved: a failure to provide fire fighting procedures for all safety-related plant areas; and a failure to follow procedures for control of combustible material. (Sections F8.2 and F8.3; [POS: 5C - Good])

Report Details

Summary of Plant Status

Unit 1 began the period at 100 percent power. On January 9, 1999, power was reduced to 20 percent power to add oil to reactor coolant pumps 1A2 and 1B1 and to repair leaks on heater drain pumps 1D1 and 1D2. The unit returned to 100 percent power on January 10, 1999, where it remained for the rest of the period.

Unit 2 continued to operate at 100 percent power during the reporting period.

Unit 3 began the period in a scheduled refueling outage. The unit went critical on December 7, 1998, for zero power physics testing but was returned to hot shutdown conditions on December 8, 1998, to repair Feedwater Startup Control Valve 3FDW-35. The unit went critical again on December 10, 1998, and power was increased to 15 percent. The unit was returned to hot shutdown conditions on December 11, 1998, and cooled to 230 degrees Fahrenheit (F) on December 14, 1998, because of secondary side chemistry concerns. Following repairs to a secondary sample cooler, the unit was restarted and went critical again on December 18, 1998, reaching 100 percent power on December 21, 1998. The unit tripped from 100 percent power on December 31, 1998, when a broken wire associated with the control rod drive (CRD) channel B trip confirm relay resulted in a spurious reactor trip confirm signal during CRD breaker testing. Following repairs, the unit went critical on January 2, 1999, and returned to 100 percent power on January 3, 1999. The unit remained at 100 percent power for the rest of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure (IP) 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 3 Restart Activities

a. Inspection Scope (71707)

The inspectors monitored portions of various restart activities for Unit 3 from December 7, 1998, to December 19, 1998. These activities included power ascension and physics testing.

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, interaction between operators and reactor engineering, and shift turnover activities. Operators had their procedures available, continually referred to them, and initialed the steps as they proceeded. Site management was available in the control room during control rod

withdrawal and approach to criticality. Operators generally used three-way communications as directed by site procedures. Operators and reactor engineers communicated frequently with each other, especially when moving control rods and during physics testing.

Several equipment and human performance problems occurred during the startup. The first problem to occur was a packing leak on Startup Feedwater Control Valve 3FDW-35. Findings for this problem are addressed in Section O1.4. The second problem to occur was a sharp increase in sodium levels in the Unit 3 feedwater and once through steam generators (OTSGs) when the turbine-generator was placed on-line. The licensee addressed these concerns adequately. The next problem occurred when operators discovered that performance testing of the reactor coolant system (RCS) hot leg high point vents was not completed properly. Findings for this problem are discussed in Section O4.1. Another problem occurred when operators inadvertently allowed RCS pressure to exceed 300 pounds per square inch gauge (psig) before completing the containment integrity checklist. Findings are discussed in Sections O1.5. The final problem occurred during startup, but was discovered after reaching 100 percent power. Specifically, calibration data for the core exit thermocouples supplying the inadequate core cooling monitor was not installed. Inspector findings for this issue are listed in Section O1.5.

c. Conclusions

The overall Unit 3 startup following the end-of-cycle 17 refueling outage was performed by operations personnel with proper command and control, control room communications, shift turnover activities, and use of appropriate procedures.

O1.3 Unit 3 Reactor Trip

a. Inspection Scope (93702)

On December 31, 1998, at 2:35 p.m., the Unit 3 reactor tripped from 100 percent power during CRD breaker testing. The inspectors responded to the control room to observe licensee actions and plant response.

b. Observations and Findings

When the inspectors arrived in the control room, the plant was stable at hot shutdown conditions. The inspectors checked indications and past trends for RCS pressure and temperature, pressurizer level, quench tank level, and turbine header pressure. All indications showed the expected post-trip results. The inspectors noted that operations personnel properly followed the emergency operating procedures with good command and control.

The licensee was performing a CRD breaker trip timing test at the time of the trip. As part of the test, operators placed reactor protection system (RPS) channel A in bypass and tripped alternating current (AC) breaker CB-10. Immediately following this action, the generator locked out, the main turbine tripped, and the reactor tripped. The licensee initiated a failure investigation process (FIP) team and determined the cause to be a

broken wire on one of the relays feeding the CRD channel B trip confirm relay. The broken wire actuated one half of the circuit for the trip confirm relay. Opening breaker CB-10 actuated the other half, which caused the generator lockout and turbine trip/reactor trip. The inspectors observed satisfactory repair of the broken wire and observed the satisfactory condition of the other wires in that cabinet.

c. Conclusions

Following a Unit 3 reactor trip, operators properly followed their procedures and exhibited good command and control.

O1.4 Isolation of 3FDW-35

a. Inspection Scope (71707)

On December 5, 1998, the licensee discovered a packing leak on startup feedwater control valve 3FDW-35. The inspectors observed licensee actions to isolate the valve for repair.

b. Observations and Findings

Following discovery, the licensee added a new Enclosure 3.65, 3FDW-35 Isolation at Hot Shutdown, to Procedure OP/3/A/1106/002, Condensate and Feedwater System, Revision 128, to provide direction for isolating valve 3FDW-35. On December 7, 1998, the licensee held a plant operations review committee (PORC) meeting to discuss the isolation of valve 3FDW-35. The PORC was required because this valve provides a safety function to isolate main feedwater following a main steam line break and also provides a non-safety backup flow path for the emergency feedwater system to feed the OTSG.

The inspectors reviewed the procedure change, attended the PORC meeting, and reviewed the 10 CFR 50.59 unreviewed safety question determination. The inspectors determined that the procedure change and unreviewed safety question determination were properly done to assure that the emergency feedwater design basis was met while valve 3FDW-35 was isolated.

The inspectors walked down the Unit 3 emergency feedwater (EFW) system before valve 3FDW-35 was isolated and found the system was properly aligned. The inspectors also observed the operators isolate the valve and found that they controlled OTSG level within a 10-inch band, properly followed their procedure, and made conservative decisions.

c. Conclusions

Operations personnel properly initiated a procedure change and properly adhered to it when isolating feedwater startup control valve 3FDW-35.

O1.5 Licensee Reports and Notifications

a. Inspection Scope (71707, 93702)

The inspectors reviewed or inspected licensee events, licensee event reports (LERs), and notifications to the NRC.

b. Observations and Findings

(1) LER 50-269/98-16, Three Interpretations did not Meet Technical Specifications (TS) Due to Inadequate Management Policy, dated December 21, 1998

On November 24, 1998, following a completion of a review of TS interpretations (TSI), the licensee discovered that three TSIs disagreed, in part, with requirements in the TS. Corrective actions specified in LER 50-269/98-03, Missed Surveillance Due to Non-Literal Interpretation of Technical Specifications, prompted the review of the licensees' TSIs. The licensee issued LER 50-269/98-16, which discussed the results of the review. At the time of issuance, the identified discrepancies were verified not to impact current operation of the Oconee units. The LER had been submitted under 10 CFR 50.73 Sections (a)(1) and (d).

(2) Retracted notification number 35087, dated November 30, Keowee Level Event - Both Units Operated Outside Selected Licensee Commitment Operating Envelope, retracted December 21, 1998

On November 30, 1998, both Keowee hydro electric units (KHUs) were started for commercial power operation. After the units had been running for approximately 19 minutes, the licensee determined that the units were operating outside the restrictions of Selected Licensee Commitment (SLC) 16.8.4. The SLC required the KHUs to operate within prescribed lake levels for the forebay (supply lake) and tailrace (receiving lake) so that the KHUs could connect to Oconee emergency loads within design time limits following a load rejection. Following the steps of KHU start procedure, the operators could not determine whether or not the units would be in a limiting condition for operation (LCO) until the tailrace level was checked after starting the KHUs. When the licensee measured the tailrace level, they found it was outside the SLC limits. The licensee immediately stopped both KHUs and returned them to an operable condition, ready for an emergency start. The licensee submitted a 10 CFR 50.72(b)(2)(iii)(D) notification based on the belief that the KHUs could not reject commercial loads and connect to the Oconee electrical loads within design time limits with the existing lake water levels. The inspectors reviewed the SLC and the procedure, and understood that the licensee's corrective actions made the KHUs available from an idle start to produce emergency power and that the commercial start had not damaged the KHUs.

On December 21, 1998, the licensee completed an evaluation and found that the lake levels on November 30 could have supported design basis emergency power requirements while running for commercial operations. The licensee retracted the 10 CFR 50.72 notification. The inspectors will completely review the evaluation captured in Problem Investigation Process (PIP) report 98-5717. Until that review is completed, this item will remain Inspector Followup Item (IFI) 50-269,270,287/98-11-01, Keowee Commercial Operation to Emergency Start Power Evaluation.

(3) LER 50-269/98-S-02, Security Access Revoked for Falsification of Criminal Record, dated December 17, 1998

On November 11, 1998, the licensee received information from a criminal history check that a contract employee had an arrest record not disclosed on his

background investigation. The licensee properly reported the occurrence pursuant to 10 CFR 73.71.(b)(1) and (d) and Appendix (G)(I)(b). This LER is closed in Section S8.4.

(4) LER 50-269/98-17, Inadequate Work Planning Results in Missed Surveillance, dated December 17, 1998

On November 28, 1998, with Oconee Unit 1 at 100 percent power, the licensee began planned maintenance on the unit's operator aid computer (OAC). With the computer out of service, the licensee was required to perform quadrant power tilt calculations normally performed by the OAC. These activities were not initiated in time to prevent exceeding the two-hour time limit between surveillances. The calculations were completed one hour and 35 minutes beyond the required completion time. The next surveillance was done at its proper time. The inspectors reviewed the documentation on the event. The licensee reported the event under 10 CFR 50.73.(a)(1) and (d).

(5) LER 50-269/98-S-03, Failure to Follow Procedures Results in Uncontrolled Safeguards Information Drawing, dated December 31, 1998

On December 7, 1998, the licensee discovered an uncontrolled safeguards drawing in the Unit 3 cable room. Work had been ongoing in the area and the drawing was inappropriately left out. The licensee reported the event pursuant to 10 CFR 73.7 (b)(1) and (d), and Appendix G (I)(b). During the initial review by the inspectors, no overt security problems were observed. This LER is closed in Section S8.3.

(6) LER 50-269/98-18, Potential Loss of Emergency Siphon Vacuum [ESV] System due to Failure Analysis Oversight, dated January 8, 1999

On December 9, 1998, the licensee concluded that there was a single failure potential with Unit 2 and 3 ESV and siphon seal water (SSW) systems. The scenario of concern was that with one train of ESV and SSW in operation as allowed by TS, one failure under certain conditions could degrade the ESV to the point it would not provide an emergency condenser circulating water (ECCW) siphon flow path to the low pressure service water (LPSW) pump suction and to the condensers for the two units. This is discussed in more detail in Section E2.3 of this report. The licensee reported the potential condition under 10 CFR 50.73(a)(1) and (d).

(7) LER 50-270/96-03, Revision 1, Technical Specification Required Shutdown Due to Inadequate Work Planning, dated January 21, 1999

During a September 18, 1996, event where the 2B high pressure injection (HPI) pump motor failed, the licensee was unable to repair the motor within 72 hours and the plant was shutdown. The licensee had reported the initial event under 10 CFR 50.72(b)(1)(A). During the intervening period, the licensee pursued investigation into TS LCO requirements as their TS upgrade program proceeded. The LER revision discussed the fact that the licensee's previous TS guidance on the length of the TS 3.3.1.a(2) LCO was in error. The LCO length should have been 24 hours instead of 72-hours for having the discharge of the HPI pumps cross-connected. As stated by the licensee, the original LER event was the only known time that the licensee has identified where the 72-hour LCO time was

applied. The inspectors have verified that the operations procedures, which previously referenced a 72-hour LCO, have been modified to reflect the 24 hour LCO for the stated condition. This was reported under 10 CFR 50.73.(a)(1) and (d).

The NRC issued the Improved Technical Specifications (ITS) for Oconee on December 16, 1998. They currently do not address the 24-hour LCO for a cross-connected HPI condition. A recent proposed TS change asked for a 72-hour LCO for the stated condition. The submittal indicated that there was low risk involved with having the cross-connected HPI condition (PIP 98-3964).

(8) Retracted notification number 35178, dated December 20, 1998, Inadvertent Engineering Safeguards Actuation on Unit 2, retracted January 19, 1999

On December 20, 1998, while testing Unit 2 Engineered Safeguards (ES) Channel 3, the licensee experienced an inadvertent actuation of that channel and its components. The inspectors were called by the licensee and responded to the site to inspect details of the event and review component trend data. The licensee concluded and the inspectors concurred, that the started components were secured before damage occurred. When the inspectors investigated, conditions were as stated in the notification with the licensee troubleshooting the ES channel components. Electrical components within the channel being tested had failed causing the actuations. The notification was made under 10 CFR 50.72.(b)(2)(ii). The licensee retracted the initial notification based on their interpretation of NUREG 1022. The inspectors will review the retraction for appropriate application of the guidance. Until that review is completed, this item is identified as IFI 50-270/98-11-02, Retraction of Unit 2 Engineering Safeguards Actuation Event.

(9) LER 50-287/98-01, Missed Surveillance Due to Inappropriate Actions, dated December 31, 1998

On December 3, 1998, the licensee discovered that several recently replaced reactor building (RB) pressure instrument tubing pieces had not been tested prior to exceeding the 200 degrees F and 300 psig containment integrity transient point. There were four 3/8-inch lines affected. The unit was above the transition point for about four hours (12:56 p.m. to 4:54 p.m.) prior to the licensee's discovery. Once discovered, the licensee entered TS 3.6.6.2 for RB integrity (48 hours) and halted further pressure and temperature increases at 186 degree F and 330 psig. On December 4, 1998, at 2:15 a.m., local leak rate tests of the tubing fittings were completed. The licensee notified the inspectors who followed the details of the recovery and reviewed the documents generated for the post-maintenance testing performed to exit the LCO. The licensee reported the event under 10 CFR 50.73.(a)(1) and (d).

(10) LER 50-287/98-02, Reactor Coolant System Pressure Limit for Containment Integrity Exceeded Due to Inappropriate Action, dated January 14, 1999

On December 15, 1998, while holding below the containment integrity transition point of 200 degrees F and 300 psig, the licensee inadvertently exceeded 300 psig by 12 psig. The operator at the controls had energized the pressurizer heaters and subsequently became distracted. Neither he nor the shift crew noticed that pressure increase until approximately a half hour later. No design

pressure and temperature limits were exceeded. The licensee returned the plant below the pressure and temperature threshold. The inspector reviewed the trend data on the event and discussed the event with the crew involved. The licensee reported this under 10 CFR 50.73.(a)(1) and (d).

As immediate corrective action, the crew on shift during the occurrence reviewed the event with the crews on all other operational shifts. The inspectors observed the first crew debrief.

(11) LER 50-287/98-03, Missed Calibration Due to Lack of Training and Lack of Formal Process, issued January 27, 1999

On December 28, 1998, the licensee discovered that a core exit thermocouple (CET) calibration had not been performed as required by TS Table 3.5.6-1 and Table 4.1-1. The five dedicated CETs for the inadequate core cooling monitor system were required for hot shutdown. The licensee reached hot shutdown at 10:35 p.m. on December 17, 1998. The licensee completed the calibration on December 28, 1998, but did not complete the as found instrumentation string checks. These were not completed until January 7, 1999, after the LER investigation personnel discovered by interview that the procedure was not completely performed. The inspectors observed performance of the subsequent satisfactory string check. The licensee stated their intention to report the event under 10 CFR 50.73.(a)(2)(i)(b).

(12) LER 50-287/98-04, Broken Wire Causes Reactor Trip During Control Rod Drive Breaker Test, issued February 1, 1999

On December, 31, 1998, due to material deficiencies in the trip confirm circuit wiring, Unit 3 tripped from 100 percent power. The details of the trip and the recovery are discussed in Section O1.3. The licensee stated their intention to report this event under 10 CFR 50.73.(a)(2)(iv).

c. Conclusions

The licensee promptly notified the NRC of the above conditions and initiated corrective action regarding the above events, where applicable. The NRC will evaluate the LERs for potential enforcement during closeout of the LERs.

O1.6 Unit 1 Power Reduction for Oil Addition to Reactor Coolant Pump (RCP) Motor Bearing Reservoirs

a. Inspection Scope (71707)

On January 9, 1999, Unit 1 was reduced to 20 percent power to add oil to reactor coolant pumps 1A2 and 1B1 motors and to repair leaks on heater drain pumps 1D1 and 1D2. The unit returned to 100 percent power on January 10, 1999. Inspectors observed part of the shutdown and oil addition.

b. Observations and Findings

The power reduction went smoothly with good command and control exhibited by the operators. The RCP motor oil addition went without a problem with the oil removed from the catch tank nearly matching that added to the reservoirs. The control room level indication returned to the correct level, approximately matching the volume of oil added. Return to power operations was marred by a minor problem with a control rod position reed switch and by a slight core flux tilt problem. The operators were attentive to these problems, consulting engineering and performing appropriate documentation on the issues. The inspectors observed that the reed switch and tilt problems cleared with appropriate administrative controls applied. The sticking reed switch problem was captured in the site's corrective action program.

c. Conclusions

With the operators exhibiting good command and control, Unit 1 was reduced from 100 to 20 percent power to add oil to reactor coolant pumps 1A2 and 1B1 motors. Minor problems during the return to power were handled well.

O2 Operational Status of Facilities and Equipment

O2.1 Operations Clearances (71707)

The inspectors reviewed the following clearance during the inspection period:

- 98-4862 SSW A Train Strainer

The inspectors observed that the clearance was properly prepared and authorized and that the tagged components were in the required positions with the appropriate tags in place.

O2.2 Containment Isolation Valve Lineup (71707)

The inspectors reviewed the following containment isolation lineup during the inspection period:

- Unit 3 Reactor Building

The inspectors observed that the lineup was in accordance with plant operating procedures and the Updated Final Safety Analysis Report (UFSAR).

O2.3 Engineered Safety Feature (ESF) System Walkdown (71707)

The inspectors walked down accessible portions of the following ESF systems:

- Unit 3 EFW
- Unit 3 Low Pressure Injection

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

O2.4 Unit 3 Reactor Building Hot Shutdown Inspection Prior to Startup (Recovery Plan Item SE1 - Material Condition Upgrade)

a. Inspection Scope (71707, 71750)

The inspectors accompanied licensee personnel on a RB walkdown inspection for material condition prior to startup.

b. Observations and Findings

On December 5, 1998, the inspectors accompanied licensee personnel on RB material condition inspections in Unit 3. 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 1, operations personnel identified several minor items. These items were determined not to impact unit startup and were entered into the licensee's work management system. There was no observed leakage, mechanical looseness, or debris that could cause operational problems.

c. Conclusions

The inspectors concluded that the licensee's reactor building tour conducted at hot shutdown prior to Unit 3 startup was thorough and detailed, with minimal discrepancies found. This was continuing indication that corrective actions dealing with material conditions in the reactor building have been effective in reducing potential operational risk. Recovery Plan SE1 remains open pending additional NRC review of plant material condition.

O2.5 Risk Assessment (Recovery Plan Item OF4)

a. Inspection Scope (71707)

The inspectors reviewed the Recovery Plan, interviewed responsible managers, and reviewed documentation for the operational focus area on risk assessment.

b. Observations and Findings

In order to improve the risk management program, the recovery plan called for: special emphasis codes on daily work lists to heighten awareness of risk, the implementation of computer software for detailed risk assessment of complex parallel evolutions, the implementation of a critical maintenance process, and development of a site directive on the risk management program.

The inspectors found that the special emphasis codes had been implemented in the work process manual and observed them being used at daily planning meetings. The work process manual had also been revised to include a critical maintenance process. The risk assessment software had been implemented, but was not fully in use. It was being used in parallel with the previous manual system. The site directive was not yet in place and the tracking of its implementation had been moved to a licensee initiative on work management process improvement. The inspectors verified that the licensee still planned to add a site directive for risk assessment as part of that initiative. This was scheduled to be in place before the next refueling outage in June 1999. Based on this review, this Recovery Plan Item is closed.

c. Conclusions

The daily risk assessment process met the goals of the recovery plan. Specific actions of the process had either been implemented or scheduled. Recovery Plan Item OF4 is closed.

O4 Operator Knowledge and Performance

O4.1 Unit 3 RCS Loop Vent Performance Test

a. Inspection Scope (71707)

The inspectors reviewed the startup procedures and interviewed personnel on the performance test procedure that was found incomplete during the second Unit 3 startup.

b. Observations and Findings

On December 9, 1998, during the Unit 3 startup, control room personnel identified that Performance Test (PT) PT/3/A/0201/05, RV Head/RCS High Point Vent Flow Test, Revision 5, had not been completed. By the procedure, the PT was required to be performed during refueling while the RCS was depressurized. The head vent portion had been completed on November 15, 1998, but the loop vent portion could not be completed at that time due to an active block tagout. This was annotated on the incomplete procedure and in the work management system for required testing. The applicable SLC did not address a specific time for performance of the venting.

Personnel reviewing the work management system missed that the procedure had not been completed in its entirety and unit startup continued. On December 9, 1998, shift personnel questioned the status of the PT, discovered that the PT had not been completed, and stopped the startup. Immediate corrective actions were to contact scheduling and engineering personnel to determine the latest date on the PT, if the PT could be done at hot shutdown, and rewrite the procedure to allow performance of the PT at hot shutdown.

On December 10, 1998, operations completed the PT on the loop vents and initiated PIP 98-5876. The latest date where the PT would have been outside its required frequency was December 15, 1998.

The inspectors reviewed the PIP and questioned why the PIP text indicated an operability was required. Interviews with the screening team revealed that the original screening was in error and there should have been no operability question. This was because the surveillance was completed within the required time limit. The PIP text also lacked any immediate or proposed corrective actions. Discussions with operations personnel indicated that the immediate corrective actions should have been entered following completion of the testing. Operation's management discussed the proposed corrective actions with the inspectors and updated the PIP on January 8, 1999.

Licensee evaluation of this event determined two inappropriate actions had occurred. First, work control personnel had removed the PT from the schedule before the entire PT had been completed. Second, operations had failed to recognize from the work

management system that the PT had not been performed and had not included this PT in the unit startup prerequisites. Planned corrective actions were to add the PT to all units' startup procedures, counsel personnel on the importance of reviewing the work management system, and place two tasks for the procedure in the refueling schedule.

c. Conclusions

The inspectors concluded that operations' failure to identify that the performance test had not been completed was a weakness in the review of startup prerequisites and in operations procedures. The work control personnel's removal of the performance test from the schedule without the test being completed was also a weakness.

O4.2 Human Performance During the Inspection Period (Recovery Plan Item P1)

a. Inspection Scope (71707)

During the inspection period the inspectors reviewed some of the findings discussed in other sections of the report for applicability to the human performance initiative under the recovery plan.

b. Observations and Findings

Examples of negative human performance occurrences were: Section O1.5, Items 4, 5, 9, 10, and 11; Section O4.1; Section O7.2; Section M1.2; and Section E2.1. Also, Sections O8.1 and Section O8.2 have negative performance components from an earlier inspection period. Some occurrences, such as Section O8.2 and Section O1.5, Items 5 and 10, were the result of individual mistakes that occurred in refueling outages. Others, such as Section O4.1 and Section O1.5, Items 4, 9, and 11, were process problems with multiple group interactions. Section M1.2 and Section E2.1 were a result of minimal instruction problems and testing problems. The LERs with potential enforcement will be dispositioned upon completion of the review.

Examples of positive licensee actions were as follows: Section O1.3; Section O1.4; Section O1.5, Items 1, 2, 6, and 7; Section E2.1; and Section E2.2. Sections O1.3 and O1.4 were continuing examples of proper plant operation. The Section O1.5 items were examples of the licensee reviewing their problems, attempting to resolve them, and reporting those required to the NRC. Sections E2.1 and E2.3 reflected good engineering effort to upgrade the plant, but with that effort some problems did arise.

c. Conclusions

General inspection period findings found human performance errors still occurring; some of which were process problems that will require longer term resolutions. There were several surveillance performance issues in this period. Recovery Plan Item P1 remains open.

The licensee was reporting findings as required to the NRC.

O7 Quality Assurance in Operations

O7.1 Mispositioning Root Cause Assessment (Recovery Plan OF1)

a. Inspection Scope (71707)

The inspectors reviewed the licensee's implementation of initiative N9740, associated with root cause analysis and with corrective actions for operational (misposition) related events, to determine if the implementation was effective.

b. Observations and Findings

In February 1997, the licensee identified an adverse trend in the number of site mispositioning events. The significant events in the late 1996 to early 1997 time frame had been inspected by the residents and dispositioned in reports. The licensee documented the trend in PIP 97-737 and initiated a Continuous Improvement Team (CIT) in March 1997. The CIT completed its study and provided its recommended actions on August 26, 1997. There were approximately 37 corrective actions for PIP 97-737. All corrective actions for this PIP were completed by December 1997 with the exception of Human Error Reduction and Assessment training. Since that time, a June 1998 Unit 2 loss of vacuum trip resulted in additional proposed corrective actions for the clearance program (LER 50-270/98-03 and IR 50-269,270,287/98-06).

In September 1998, a routine licensee assessment of the misposition area was performed. The assessment was documented in PIP 98-4205. The PIP stated that previous corrective actions had not been effective in preventing recurrence of the misposition problems. The PIP provided additional corrective actions and recommendations in the areas of operational bench marking activities, additional clearance program changes, training, and CIT activities. Of particular concern in the PIP details was that the general licensee staff was unaware of mispositioning problem details and specific training had not been provided. Many of the proposed corrective actions have yet to be completed.

The inspectors attended the meetings of the CIT in September 1998 and December 1998. Due to stated pending corrective actions identified above, no CIT action items were generated in the meetings. The team had built a database of mispositioning events from 1992 to 1998. This database divided the mispositioning contributing factors into 44 potential causes. However, the database lacked a breakdown of pre-recovery plan and post-recovery plan items that would have helped to identify if the root causes were still present for the events. The database also did not break down the items by system or component which would also help to identify areas for improvement. One of the contributing factors was listed as "Unknown." The unknown category identified 51 PIPs due to insufficient information or investigation still in progress. PIP 98-4205 recognized that corrective actions for mispositioning events were inadequate and the process needed improvement.

This Recovery Plan item will remain open pending completion of licensee corrective actions for mispositioning events.

c. Conclusion

The inspectors concluded that the licensee's implementation of the mispositioning root cause assessment initiative (N9740) was not adequate to close this Recovery Plan item. Recovery Plan Item OFI remains open.

O7.2 Overtime Control and Documentation

a. Inspection Scope (71707)

The inspectors reviewed NSD 200, Overtime Control, Revision 5, selected overtime extension requests, and licensee overtime reports for 1998. The inspectors also interviewed management personnel on the requirements and interpretation of NSD 200.

b. Observations and Findings

The licensee's overtime administrative reports documented individuals requesting overtime and the amount of overtime worked each period. The reports also listed a description of the work performed. The overtime administrative reports also provided concerns regarding licensee compliance with their procedure. The description varied from specific jobs such as nozzle dam installation to general descriptions such as motor operated valve outage support. This type of general description made it difficult to assess the actual impact of overtime work on safety.

NSD 200 contained specific requirements for limiting overtime and the safe use of overtime. The administrative reports reviewed from early 1998 listed as concerns (noncompliance): management approval signed by unauthorized persons, management approval signed prior to the required personnel assessment being performed, one individual as both assessor and management designee, and supervisors assessing themselves. These concerns were listed in the report and continued to occur through the October/November 1998 report. During discussion with management, the inspectors found that licensee managers were aware of the raw numbers of noncompliances and the managers indicated that they had provided corrective action. In August 1998, NSD 200 was revised and all employees were issued a training package to describe the requirements of NSD 200.

A review of the PIP database revealed eight PIPs with noncompliances of NSD 200 requirements, five prior to August of 1998 and three after August 1998. This number of PIPs did not reflect the total number of identified noncompliances in the monthly administrative reports. The categorizations of the noncompliance in the PIPs in general related to a common theme of personnel exceeding the 72 hours in seven days overtime limit. The administratively reported noncompliances as discussed above were in eight reports covering the year from January to December 1998. Most of the administrative reports contained multiple examples of non-compliances with the overtime requirements. The inspectors could not find an adverse trend PIP that addressed overtime.

The inspectors also reviewed the referenced PIPs to determine what corrective actions had been completed. The PIPs reviewed listed the corrective actions as: "counsel affected individuals" and "train on NSD 200 to reduce confusion." The corrective actions were stated to have been completed. The inspectors are continuing a review of events and the personnel involved for overtime concerns. This item will be identified as Unresolved Item (URI) 50-269,270,287/98-11-03: Overtime Procedures and Controls.

c. Conclusions

The inspectors concluded that the demonstrated deficiencies in the documentation and understanding of overtime requirements warrants further NRC inspection and resulted in an unresolved item.

O8 Miscellaneous Operations Issues (71707, 92700, 92901)

O8.1 (Closed) URI 50-269,270,287/98-10-02: Inappropriate Action Results in Unexpected ESF Component Actuation

This URI was opened when standby bus tie breaker SK2 unexpectedly closed during simultaneous testing of ES channels on Unit 3 and weekly surveillance testing on KHU-2. The URI was opened pending NRC understanding of two corrective actions to previous Violation (VIO) 50-269,270,287/97-16-01: Failure to Implement Nuclear Systems Directive 408. The remaining questions concerned: (1) why an operations guide listed as a corrective action to the violation was removed and (2) whether or not training specified as a corrective action to the violation was completed.

The inspectors further reviewed the response to VIO 50-269,270,287/97-16-01, reviewed PIP 97-4276, and discussed the open questions with operations management. The operations guide had been removed in May 1998 and replaced with weekly reviews of the testing and maintenance schedule by the operations work process group. These reviews were intended to prevent recurrence of the interaction problems described in this URI. The licensee did not take all stated actions that could have prevented this event.

The inspectors also confirmed that the specified training had been planned, but had not yet started. A change to the lesson plan on emergency power logic had been completed in May 1998, with the intent that as training was scheduled on the lesson plan, operators would be trained on the event discussed in VIO 50-269,270,287/97-16-01. Personnel in the above mentioned work process group were to be included in this training because they were licensed operators. As of December 17, 1998, no training had occurred on the emergency power logic lesson plan. Based on the fact that this similar unexpected breaker actuation occurred, the inspectors determined that the actions taken to date in response to VIO 50-269,270,287/97-16-01 did not correct the problem and constituted a violation of NRC requirements. The violation was failure to implement NSD 408. This violation constitutes an additional example of VIO 50-269,270,287/97-16-01 and is not being cited individually. No additional response to VIO 50-269,270,287/97-16-01 is required. Further corrective actions for this additional example are expected to be taken in conjunction with corrective actions for the previously cited violation.

O8.2 (Closed) LER 50-269/98-15: Loss of Onsite Emergency Power Due to Planned Testing, Inappropriate Action, and Inadequate Evaluation of the Impact of Testing on the Components

This event was originally discussed in IR 50-269,270,287/98-10. It involved two occurrences which made the Keowee units inoperable. The first occurred when a Keowee operator used the wrong switch to stop KHU-1 after testing and resulted in damage to the KHU-1 supply and field breakers. The second occurred when a temporary minor modification, installed in KHU-2 for planned testing, did not function as expected and a float valve in the KHU-1 governor oil system malfunctioned.

The licensee performed the following corrective actions: they replaced the damaged breakers; added a permanent caution label to the master selector switches for both Keowee units, warning the operators not to manipulate the switches while the units were operating; they added a timer to the temporary modification; replaced the float valve; and committed to replace the float valve and/or ball with another design less susceptible to failure.

The inspectors reviewed the licensee's root cause determination and corrective actions taken and determined them to be appropriate. The inspectors also determined that the action of the Keowee operator to manipulate the wrong control switch constituted a failure to follow Procedure OP/0/A/2000/041, Revision 18, Keowee Modes of Operation. 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 50-287/98-11-04: Personnel Error at Keowee Results in Overheating the Closing Coils for the Keowee Unit 1 Field Breakers. This LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726, 92902)

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

- WO 98121278 — "A" and "B" Hydrogen Tank Inspections
- PT/1/A/0600/013 — Motor Driven Emergency Feedwater Pump Test, Revision 37
- WO 98106701 — Replace Starter Contacts, Springs and Coil on Open Side of Valve 3LP-17
- WO 98011497 — Implement Minor Modification ON OE-11479, Replace Relay 387T With New Type on Transformer CT3
- WO 98105832 — Repair Keowee Unit 1 Field Supply Breaker and Field Breaker
- IP/0/B/1606/09 — Preventive Maintenance and Operational Check of Freeze Protection, Revision 2
- OP/1/A/1102/20 — Shift Turnover, Enclosure 5.12, Cold Weather Check Sheet, Revision 76
- IP/0/A/0301/03T — RPS Computer Calc for Power Range Calibration Instrument, Revision 20
- IP/0/A/0301/03V — Procedure for Setting High Flux Trip, Revision 26
- PT/0/A/0811/01 — Power Escalation Test, Revision 23

- PT/2/A/0261/10 Essential Siphon Vacuum System Test, Revision 4
- WO 98080284 Model Work Order for Freeze Protection Activities
- IP/0/A/0200/41D ICCM Core Exit Thermocouple Calibration, Revision 21

b. Observations and Findings

In general, 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.

In conjunction with the Keowee testing results addressed in Sections E2.2 and E2.7, the inspectors observed the replacement (WO 98106701) of the movable and stationary contacts for all three phases, the three springs for the movable contacts, and the coil for the opening starter in valve 3LP-17. The coil had physical damage to the insulation covering, the contacts did not show pitting, and the springs were not deformed. Tests indicated that the removed coil was acting slower than a new coil by a factor of three. This problem was entered into the licensee's corrective action program for further evaluation.

c. Conclusion

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

M1.2 Cold Weather (CW) Preparations

a. Inspection Scope (71714)

The inspectors reviewed the licensee's CW plan, observed licensee performance of procedures, performed walkdowns of the plant, and observed licensee actions during severe weather.

b. Observations and Findings

The controlling procedure, IP/0/B/1606/09, Preventive Maintenance and Operational Check of Freeze Protection, Revision 2, for electrical heat trace and heater controls directed plant personnel to perform the following: preventive maintenance (PM) on cold weather devices such as heat trace, thermostat heat detectors, and heat controllers; physically observe insulation and repair as necessary; and perform a cold weather checklist when the outside temperature was expected to go below 35 degrees F. The inspectors observed and reviewed the following: the heat trace controls were set to

activate at 50 degrees F; the program identified 105 items of heating equipment with 38 work support items issued; seven work requests were issued to repair or replace degraded or obsolete items; five minor modifications were issued due to old equipment; and various work activities were also observed. The controlling procedure for heat trace PM and the work activities was considered good. Additional discussions of cold weather preparations are in Section E2.1 of this report.

Main Plant Observations

For the auxiliary building, turbine building, the borated water storage tanks, and other water bearing tanks, the inspectors observed that CW heat trace indications were functional. Outlying instruments were insulated and the heating procedure had been used to check the alarm capability and functionality of the circuits. Standing work order 41852, Winter Weatherization, installed plastic sheeting on openings, repaired roofs, cleaned drains, inspected roof hatches, etc., on the turbine and service buildings and general grounds.

The CW plan and procedure did not address louver inspections or operation prior to cold weather on the main plant or other buildings (see ESV Building below). As a part of their rounds, the non-licensed operators checked building louvers once per shift, when they were required to be closed. The inspectors performed a walkdown of the plant when the outside temperature reached 30 degrees F. The inspectors observed that the Unit 2 and 3 turbine building louvers were closed off, with some appearing not to be fully functional, and the majority of the Unit 1 louvers were open. With the plant in operation, there was no immediate operational concern. The inspectors discussed this observation with licensee personnel and were informed that the Unit 1 louvers should have been closed. The licensee closed the louvers prior to the next cold weather. In accordance with OP/1/A/1102/20, Revision 76, Shift Turnover (round sheets), the operators had yet to begin their rounds for louver inspection that would have caught this problem. The louvers not being addressed in the procedure was considered to be a weakness in CW plan.

The buildings addressed by IP/0/B/1606/09 were heated by auxiliary steam system via the plant steam heat system. The plant steam heat system was addressed by the CW plan and plant procedure MP/0/B/3007/59, Plant Heating - Testing, Revision 1. Per discussions with the licensee, the individual heater strings were not to be tested this year. Personnel within the buildings and the operators were expected to observe and report low temperatures or non-functioning heaters. The inspectors toured the auxiliary and turbine buildings and found no cold areas. Following a discussion between the inspectors and licensee personnel, the testing procedure was performed and eight of the 29 heaters were not operable. The inspectors observed that six of these eight heaters were located in one area of the Unit 3 turbine building basement. With the unit operating, there were no immediate operational concerns. The licensee issued work requests to repair the heaters. The material condition of the plant heating system was considered poor.

Outer Buildings in the Protected Area

These buildings (i.e., warehouses, radwaste, reactor coolant repair buildings) were not addressed in the procedure. Similar to the buildings discussed above, they were heated by auxiliary steam. The expectation of reporting heating problems was the same. The

inspectors toured these buildings and found no sub-freezing zones or areas. Historically, the licensee has been active in tending to emergent problems in these buildings.

Standby Shutdown Facility (SSF)

The SSF was not addressed in the CW plan. This building, as well as the Keowee units, have been evaluated by the licensee in PIP 96-639 for additional freeze protection or addition to the CW plan. The SSF has no exposed pipe or instrumentation and is heated by electric heating. It also contains security forces which man the building 24 hours a day. The operator rounds sheet contained SSF ventilation checks. As with all other areas in the building, the SSF safety-related breaker, control, pump, and diesel rooms were found to be acceptable. Aside from the SSF emergency control room, all the safety-related areas were below ground level and warmed by the earth's residual heat.

ESV Building

This building was recently constructed to house safety related ECCW siphon support equipment. The PM instructions had not been added to the general CW procedure but, as stated by the licensee, will be incorporated prior to next winter. This building was designed to be heated by the warmth of the running ESV equipment supplemented by electric space heaters. This building's exposed piping and the modified intake structure components were to have heat tracing installed and tested in December 1998. Prior to the heat trace installation completion, inspections of the building were generally acceptable, except as discussed in Section E2.1.

Elevated Water Storage Tank

This structure provides fire protection head for the plant and is covered by the CW plan. Instrumentation in the structure was found to be properly heat traced.

Intake Structure

[Condenser Circulating Water (CCW) Pumps]

The non-safety related CCW pumps were in the CW plan and covered by procedures. The exception to this was that the Unit 2 and 3 pumps have been recently, extensively modified to include new SSW piping that seal the packing areas of the pumps and cool the motors. As with the ESV building modification, these PM changes had not yet been incorporated into plant CW procedures.

At the time of the freeze protection inspection, the licensee had yet to complete heat tracing and testing. The inspectors were told that the modification of these systems would setup and test the new heat trace under the controls of the modification program. See Section E2.1 for problems that occurred during freezing weather in December 1998.

[Safety-related ESV and SSW Equipment]

The ESV system and SSW supply to the ESV pumps are safety-related. Similarly, as with the CCW discussion above, the modifications to this heat trace equipment was to occur in December 1998. Attendant testing and PMs were to be completed by the licensee. These PMs were to be added to the CW plan. See Section E2.1 for problems that occurred during freezing weather in December 1998.

Keowee Hydro-Electric Plant

This plant was not in the CW plan. Keowee was covered by a PIP 96-639 evaluation. All necessary piping and instrumentation were contained within the heated plant structure. The expectation was that the permanent staff would discover CW problems and have them repaired. Most of the vital equipment was below ground and protected by thick concrete. The various areas were heated by electric heating. The inspectors toured the areas without finding any deficiencies.

Hydrogen and Nitrogen Sheds

These sheds were not covered by the CW plan. On January 6, 1999, with outside temperature below freezing, the rupture disk on the "C" hydrogen tank burst and the tank blew down. Operations was notified by security that they had heard a noise. The fire brigade was called out and reached the area in about 8 minutes. Inspectors were in the control room during the event and one reached the shed area about the same time as the fire brigade. Upon arrival at the shed, the fire brigade noted that the blow down had stopped, and using a detection instrument, found no hydrogen present. Although carefully reviewed by operations, there was no emergency plan entry criteria met.

The tank relief discharge pipe blew out just down stream of the tanks' rupture disk. An ice plug was visible downstream of the blow out point. The licensee had not determined the cause of the rupture, but had continued to investigate this item, had contacted the hydrogen skid vendor for support, and entered the problem into their corrective action program at the end of the report period.

c. Conclusions

The general cold weather preparations for electrical trace and electrical space heating systems were comprehensive, identified the electrical heating equipment required by the program, and gave instructions on adjusting the heating control equipment. The controlling procedure for cold weather electrical heating protection and the work activities were good.

Weaknesses were identified in the cold weather preparations program. The area heaters in the plant steam heating system were not tested prior to the onset of cold weather. Turbine building louvers were not verified as closed prior to cold weather.

The material condition of the plant heating system was considered poor after testing identified 8 out of 29 heaters as inoperable with the majority in one area of the Unit 3 turbine building basement.

M1.3 Improved Troubleshooting (Recovery Plan Item TD5)

a. Inspection Scope (62707)

The inspectors reviewed the Recovery Plan, interviewed responsible managers, observed performance, and reviewed documentation for the Improved Troubleshooting Temporary Defense.

b. Observations and Findings

The inspectors reviewed Procedures IP/0/A/0100/001, Controlling Procedure for Electrical and I&C Troubleshooting and Corrective Maintenance, Revision 15, and MP/0/A/1800/022, Controlling Procedure for Troubleshooting and Corrective Maintenance, Revision 15. Both procedures met the intent of the recovery plan in that they provided for a risk assessment and documented troubleshooting plans. Both procedures also provided for management oversight. This management oversight included at least a supervisor approval of low risk activities, including a justification when no troubleshooting plan was used. Management oversight also included engineering and operations review of medium and high risk activities.

The inspectors observed performance of one maintenance crew under Procedure IP/0/A/0100/001. In most cases, the crew implemented the risk assessment and troubleshooting plans according to procedure, but in one instance did not fully justify why no troubleshooting plan was used on a low risk activity. This recovery plan item will be left open in order to check the differences between procedures, to watch troubleshooting using procedure MP/0/A/1800/022, and to observe troubleshooting activities by different crews.

c. Conclusions

Mechanical and instrumentation troubleshooting procedures met the intent of the recovery plan. With one exception, the procedures were implemented properly. Recovery Plan Item TD5 remains open.

M1.4 Material Condition (matcon) (Recovery Plan Item SE1)

a. Inspection Scope (71707, 62707)

During the period, the inspectors continued evaluation of the plant material condition efforts performed to date by the licensee. The licensee had a special team inspect the units for material condition problems and hang special matcon tags to identify the found conditions. The inspectors inspected portions of all three units after the licensee had taken the major actions to clear approximately half their matcon inspection tags following repairs. Using a sample, the goal of the inspection was to identify any matcon tags associated with safety-related equipment that may be degraded or non-functional.

b. Observations and Findings

The inspectors toured all three units' emergency core cooling equipment rooms and the auxiliary building penetration rooms. It was immediately noticeable that the large number of matcon tags initially hung (approximately 4500) had been removed and the problems fixed. The licensee stated that there were approximately 2100 tags remaining. On a sampling basis, the inspectors observed about 20 to 25 tags remaining per room on average. The observed tags were not associated with conditions that could cause problems with equipment operation nor was the equipment disabled. The typical items remaining were hangers and bolts on walls from previously abandoned equipment. To date, the matcon team have yet to inspect the bleed and transfer pump rooms, the SSF, the turbine building, and portions of Unit 1.

The inspectors also did a general review of plant deficiency tags. These tags were hung by individuals other than the special matcon team. The number of normal plant deficiency tags was low. The oldest of those sampled was 1997 vintage. The plant deficiencies associated with these also were not disabling conditions or conditions that affected the operability of the safety related equipment. The licensee stated that there were 344 open deficiency tags for three units.

During the inspections, the inspectors identified approximately 10 other minor equipment problems that were reported to the operations staff. The staff had deficiency tags hung for these items.

In the rooms inspected, the general condition was good. The general plant areas exhibited chipped and peeling paint and some rust. These housekeeping conditions do not affect general component operability at the present time. The exhibited conditions made it difficult to identify individual problem areas. The remaining matcon tags and housekeeping have been discussed by the licensee's management with no firm schedule or repair effort outlined. The recovery plan item remains open.

c. Conclusions

The licensee has made large strides in improving general plant conditions by implementing and carrying out a material condition upgrade and repair effort. Further repairs and upgrades have been discussed, but the licensee has yet to produce a scope or schedule of future repairs. Recovery Plan Item SE1 remains open.

M3 Maintenance Procedures and Documentation

M3.1 Inservice Testing Program

a. Inspection Scope (73756)

The inspectors reviewed portions of the licensee's inservice testing (IST) program, entitled "ASME Inservice Testing Program," Revision 24, to determine if the testing specified was in accordance with the requirements of the TS and the CFR. This document identified the licensee's current requirements for testing American Society of Mechanical Engineers (ASME) Code Class 1, 2, and 3 pumps and valves.

b. Observations and Findings

The IST program applied to the third inservice testing ten year interval (120 month period) for Oconee. This interval started July 1, 1992 and ends June 30, 2002. Through TS 4.0.4 and 10 CFR 50.55a, the IST of Oconee's pumps and valves were required to comply with the following code and standards, except where relief was granted by the NRC:

- Pumps: ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWP, 1986 Edition.
- Relief Valves: ASME/ANSI (American National Standards Institute) Standard OM-1987, "Operation and Maintenance of Nuclear Power Plants," Part 1.
- Other Valves: ASME/ANSI Standard OM-1987, "Operation and Maintenance of Nuclear Power Plants," with OMa-1988 Addenda, Part 10.

The inspectors found that the testing specified in the licensee's IST program was generally consistent with the requirements of the above code and standard. However, the inspectors identified a deficiency in the stroke timing specified for motor-operated valves. Standard OM-1987, OMa-1988 Addenda, Part 10, required that valves be tested "full-stroke during plant operation to the position(s) required to fulfill its function(s)." Further, this standard required that the testing of power-operated valves include measurement of stroke time for comparison with the limiting value(s) specified by the owner. Contrary to this, paragraph 4.2.10 of the licensee's IST program stated that motor-operated valves (MOVs) active in both the open and closed directions would be exercised in both directions but stroke-timed in only one direction. The inspectors reviewed the following examples of the licensee's testing procedures and verified that stroke times were only measured in one direction for MOVs with active safety functions in both directions, such as main steam valve 3MS33 and low pressure injection valves 1LP15 and 2LP15:

- Procedure PT/1/A/0152/012, "Low Pressure Injection System Valve Stroke Test," Revision 3 (measures stroke time of MOV 1LP15)
- Procedure PT/2/A/0152/012, "Low Pressure Injection System Valve Stroke Test," Revision 7 (measures stroke time of MOV 2LP15)
- Procedure PT/3/A/0152/015, "Main Steam System Valve Stroke Test," Revision 2 (measures stroke time of MOV 3MS33)

The inspectors identified the licensee's failure to require MOV stroke time measurements in both directions for MOVs with active safety functions in both directions (open and closed) as Apparent Violation (EEI) 50-269,270,287/98-11-05, Stroke Time Each MOV to Its Safety Position(s). This EEI will remain open for a reasonable period of time to allow the licensee to develop corrective actions.

c. Conclusions

The testing specified by the licensee's IST program was generally consistent with the applicable regulatory requirements with the exception of an EEI identified involving inadequate stroke timing of MOVs. This EEI will remain open for a reasonable period of time to allow the licensee to develop corrective actions. When closing this EEI, the inspectors will review the licensee's completion of IST Problem Investigation Process (PIP) corrective actions referred to in Section E8.8 (PIPs 0-O98-159, -165, and -179).

M3.2 Scope and Scheduling of Inservice Testing (73756)

The inspectors conducted a review to assess the scope of valves which the licensee had selected for IST and the licensee's justifications for deferral of valve tests from quarterly to cold shutdown or outage testing. The review concentrated on the HPI system. The IST program, plant drawings, and IST database entries were examined to determine if the applicable requirements referred to in Section M3.1.b were met. The inspectors found that the proper valves had been selected for the IST program and that the licensee's justifications for deferrals were acceptable. The applicable requirements were met.

M8 Miscellaneous Operations Issues (92902)

M8.1 (Closed) IFI 50-269,270,287/97-12-04: Maintenance Oversight

During observation of alteration of transformer tap positions for the Keowee main transformer and unit startup transformer, a question was raised regarding whether or not this work required verification by quality control (QC). This IFI was opened pending a review of the quality assurance (QA) requirements.

The inspectors completed a review of the QA requirements as presented in the Duke Topical Report, DUKE-1. Table 17.0.1, Conformance of Duke's Program to QA Standards, Requirements and Guides, lists Regulatory Guide (RG) 1.30, Rev. 0 which incorporates ANSI N45.2.4-1972 and RG 1.116, Rev. (0-R) which incorporates ANSI 45.2.8 1975 for inspection of mechanical systems and equipment. These ANSI standards do not provide great details on the extent of QA inspection to be performed. The details are up to the licensee and are documented in the licensee's implementing procedures. Duke has provided a Duke Power Nuclear Inspection Program Manual Procedure. QA E-3, Electrical Cable and Cable Tray Inspection, as one of the procedures in the Nuclear Inspection Program Manual.

QA E-3 states if leads are listed in the procedure with double verification, QC verification is not required. Tap alteration was done by minor modification OE 9370 which used a out-of-normal sheet to record the tap changes and at the time the work was done, the out-of-normal sheet was thought to be part of the procedure. However it was later determined by PIP 97-2600 and PIP 97-2845 that the out-of-normal sheet was not considered part of the procedure, and therefore QC should have applied for this activity.

This misinterpretation of QA E-3 resulted in a violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings. However this non-repetitive, licensee identified and corrected violation is being treated as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-269,270,287/98-11-06, Failure to Follow Procedure. Accordingly, IFI 50-269,270, 287/97-12-04 is closed.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support for Cold Weather Preparations and the Survey and Analysis for the Adequacy of Freeze Protection

a. Inspection Scope (37551, 92903)

The inspectors observed, discussed, and reviewed engineering support activities for cold weather preparations and the engineering survey and analysis for the adequacy of freeze protection.

b. Observations and Findings

ESV Building

During a review of cold weather preparations, the inspectors observed that a non-safety related louver in the ESV building was partially disassembled. The louver had been disassembled to connect temporary power from a motor control center (MCC) inside the ESV building to some craft trailers located next to the building. Enclosure 5.12, Cold Weather Checklist, of Procedure OP/1/A/1102/20, Shift Turnover, Revision 76, required the following: that any maintenance or modification to buildings, having the potential for cold weather to affect operating equipment or components, shall be sealed and/or heated appropriately; and that these louvers be closed when the ambient air temperature is less than 35 degrees F. The inspectors observed that the disabled louver was not sealed and could not be closed if the ambient temperature were to become less than 35 degrees F. At the time of the CW inspection, there were no observed operational concerns due to available building heat.

The inspectors reviewed WO 98076810, Temporary Power to Three Trailers Near ESV Building, and determined that the WO had installed the temporary power, the evolution had received an engineering review, and the evolution was determined not to be a temporary modification. The engineering review did not specify a routing for the temporary power feeds.

The MCC used for temporary power did energize building space heaters, which was a system important to safety. The MCC had sufficient ampacity to carry the loads. The inspectors determined that the louver was partially dismantled without oversight for routing of the cables. The staff personnel who did the installation had not identified the routing as a problem. Due to the fact that ESV building temperatures were above 35 degrees F and non-licensed operator rounds had yet to begin that would have self-identified this problem, there were no operational concerns. The dismantling of the ESV building louver without adequate engineering oversight or recognition of the potential problem constituted a weakness. Once notified by the inspectors, the immediate licensee corrective actions taken consisted of rerouting the temporary power to a different building that did not contain safety-related equipment or supply power to systems important to safety and restoring the louver to operable status.

Intake Structure

On December 28, 1998, with outside temperature dropping toward freezing levels, control room annunciation alerted operations to the fact that essential siphon vacuum system float valves 3ESV-1 and 2, for Unit 3 had potential valve freezing problems. These safety-related valves support the siphon path for ECCW. Outside temperature was still above freezing. As an operations action, a temporary heating system consisting of light bulbs and portable generators was installed when the temperature indication reached 35 degrees F. When the outside temperature reached 31 degrees, additional heaters were installed and the valves were tented. At this point, operations entered TS 3.19 for Units 2 and 3. Engineering had been called several times during the December 28 through 30, 1998, period to support evaluation of the conditions. A FIP team was formed to assist in problem evaluation and resolution. Operability checks performed by the licensee and the inspectors detected no problems on the other ESV valves.

Additional reviews and observations by an FIP team indicated that Nuclear Station Modification (NSM) 3300, which installed the non-safety-related thermocouples on the valves, was not implemented properly. The wires for the thermocouples on both valves had been rolled inside a panel. This created two additional thermocouple junctions for each valve that interacted with the installed detectors and resulted in false readings. Testing of this new installation was not complete enough to detect the problem. When the wiring error was corrected, 3ESV-1 and 2 indicated an actual 80 and 73 degrees F, respectively. The inspectors verified that operations exited the TS 3.19 before the LCO time expired.

The false temperature indication on the Unit 3 ESV float valves forced the operators to declare the ESV system inoperable. The inspectors considered the NSM 3300 indication a mis-installation and subsequent inadequate testing to be weaknesses.

Similarly, temperature indication on two CCW pumps' SSW sealing and cooling lines was lost. Per Modification 32932 completed in December 1998, the licensee had not calibrated two non-safety-related, newly added heat trace thermostats on two different CCW pumps (3A and 2D pumps). The motor cooling indication impulse lines on one pump and the seal flow indication on the second pump froze. The licensee responded rapidly, determining that actual flow to the components had not frozen. On discovery, the thermostats were properly calibrated. Additional discoveries revealed that leads were rolled on one thermostat and that testing had not been properly performed. When the rework was completed, the heat trace was returned to service. Until that was completed, operations had increased their rounds on all CCW pumps. Licensee and inspector check of other modified pumps revealed satisfactory parameter indication and heat trace performance. The inspectors considered that the inadequate installation and testing of these thermostats to be a weakness.

Both of the above heat trace problems could have been avoided. The licensee was continuing their FIP team investigation at the end of the inspection period and had captured the problems in their corrective action program. The discovered problems were not in accordance with station directives for modifications and post modification testing. Due to the fact that these problems were on non-safety-related heat trace equipment, no enforcement action will be taken.

General

The inspectors observed that the licensee performed a survey which indicated that the coldest weather temperatures recorded at the site were -7 degrees F in the 1890s and -5 degrees F in the 1940s. On one occasion, sub-freezing temperatures lasted for 163 hours. This was the basis for the analysis of freeze protection for the ESV system and the CCW pump seal and motor cooling water system. The inspectors did not observe a similar survey or analysis for other existing systems or components.

The inspectors questioned the acceptance of adequate cold weather protection, during possible conditions of -7 to -5 degrees F, for other items such as the existing heat trace to borated water storage tanks, the instrumentation for the elevated water storage tank, and stagnant lines in various systems. As a result, the licensee issued PIP 98-5929 to

document the basis and criteria for sizing the freeze protection equipment. The inspectors reviewed the completed PIP, which indicated that engineering personnel verified the adequacy of the protection for these items using calculations. The licensee and inspectors determined that the freeze protection for existing installations was acceptable to -10 degrees F.

c. Conclusions

Poor engineering judgement was shown when a temporary power installation from the essential siphon system building received an engineering review without a specified routing path. Temporary power was tied into a motor control center that also supplied power to a system important to safety.

Dismantling of a vent louver (required to be closed during cold weather) on the essential siphon vacuum building in order to provide a temporary power path, was not detected by installers or building users as a configuration control problem on support systems important to safety. This was considered a weakness.

A wiring error and inadequate testing during the installation of non-safety-related temperature indication for the Unit 3 essential siphon vacuum system float valves gave the operators a false temperature indication and caused Units 2 and 3 to be placed in an unnecessary limiting condition for operation. Similarly, two thermostats on two condenser circulating water pumps' support equipment instrumentation were not properly installed, calibrated, or tested.

The survey and analysis of the historical outside temperature data and using the information to develop freeze protection requirements for the essential siphon vacuum system was good. The same type of analysis was applied to verify the adequacy of existing freeze protection equipment used at Oconee.

E2.2 Keowee Emergency Power and Engineered Safeguards (KEPES) Test Review

a. Inspection Scope (37551, 92903)

The inspectors reviewed the completed KEPES test procedure, observed selected data, discussed the overall testing activities with licensee personnel, and observed engineering followup support activities associated with test discrepancies.

b. Observations and Findings

The KEPES test was performed in proper and complete manner. The test met specified acceptance criteria. The inspectors reviewed the completed data and discussed results with the licensee's staff. The licensee was still analyzing the potential changes to the Keowee systems. Discrepancies and minor administrative and process problems that did not affect the desired out come of the test were handled well. Followup of discrepancies involving three phase power to valve 3LP-17, are discussed in Section E2.7. The inspectors found the following: The data from the test appeared to be adequate in that all necessary information was obtained; the test discrepancies did not affect the test data; the 3LP-17 valve performed the required safety function; and all other systems associated with Keowee performed as expected.

c. Conclusions

The Keowee Emergency Power and Engineered Safeguards test was performed well with the test meeting acceptance criteria.

E2.3 Single Failure Potential on Unit 2 and 3 Essential Siphon Vacuum and Siphon Seal Water Systems

a. Inspection Scope (37551)

On December 9, the licensee concluded that there was an interactive single failure potential with Unit 2 and 3 ESV and SSW systems. The inspectors reviewed the circumstances surrounding this issue.

b. Observations and Findings

The scenario of concern was that with one train of ESV and SSW in operation as allowed by TS, one failure under certain conditions could degrade the ESV to the point it would not provide an ECCW siphon flow path to the LPSW pumps' suction.

Briefly, the TS allowed operation of a unit's single LPSW pump to provide one train of SSW flow to both units' ESV pumps, which were safety-related, and CCW pumps, which were not safety-related. The second train of SSW to ESV and the CCW pumps came from the other unit and was manually valved out. Normal train alignment on the unit that provided SSW flow, allowed a second LPSW pump to provide SSW flow through the unit's cross-connected trains. The second pump was normally off.

If a loss of offsite power (LOOP) event occurred without an ES actuation combined with the single failure of the running LPSW pump, LPSW flow to the SSW and then to the ESV pumps could be lost. This is because the standby LPSW pump would not automatically start without an ES signal. The ESV pumps would be re-energized with an emergency power source within two minutes of the LOOP. Without seal water to the ESV pumps, the vacuum source provided by ESV that keeps the CCW pipes free of air could be degraded. The degradation could cause the loss of siphon flow. Without manual realignment of the other train of SSW on the unaffected unit or operator's action to start the second pump on the affected unit, no LPSW pump would be available for SSW flow for ESV vacuum pump seal supply.

Not considered in the scenario was a valved-in train of high pressure service water (HPSW). The HPSW is a diverse non-safety-related backup to LPSW. The HPSW would restart with emergency power re-initiation and this could provide both seal flows. The licensee did not take credit for HPSW since that system was non-seismic. Therefore, under the scenario, the ESV could be technically inoperable.

As immediate corrective action, the licensee cross-connected both trains of SSW, one from each unit, to provide reliable ESV and SSW flow. Additionally, the licensee changed procedures to support this alignment. The inspectors verified that the above occurred and that the alignment functioned to provide required seal flow. The inspectors observed that the above scenario was not discovered during system modification development. On the other hand, the system engineer review of the system

interactions disclosed the low probability scenario and reported it through their corrective action program (see Sections O1.5 and O4.2). This event was reported in LER 50-269/98-18. Additional review of the adequacy of the design process as it relates to the scenario described above will be performed in the closure of the LER.

c. Conclusions

As corrective action for a scenario involving an unexpected ESV-SSW interation, the licensee took prompt corrective action to realign the system and change applicable procedures.

E2.4 Corrective Action PIP Backlog - Management Exceptions (Recovery Plan Item SA1)

a. Inspection Scope (37550, 40500)

The inspectors reviewed the licensee's processes for classifying open PIP corrective actions as management exceptions and evaluated the timeliness of some of the older PIP corrective actions that had been granted management exceptions.

b. Observations and Findings

Management exceptions were found to be a backlog of PIP corrective actions, although not included in the accounting of the backlog recognized by Recovery Plan Item SA1 under Management Focus Area: Self Assessment (Initiative N9830). Corrective actions were assigned to this category when the associated work could not be completed due to constraints such as the need for an outage, awaiting parts, management decisions, etc. The inspectors found that this category of PIP corrective actions included both more significant events (MSEs) and less significant events (LSEs), and involves issues from both onsite and offsite. As of November 1998, there were a total of 463 PIP corrective actions with management exception. Of those 365 were LSEs and 98 were MSEs. Of those 98 MSEs, 17 were 3 years old or older which makes up approximately 17 percent of the open MSEs. The oldest item was 10 years old and the next oldest item was 8 years old. The inspectors also noted that the total number of management exception PIP corrective actions has trended up from the January 1998 total of 310 items. The inspectors reviewed 3 Management Exception PIP corrective actions and made the following observations regarding corrective action timeliness:

- PIP 4-O88-0025 dated January 29, 1988 identified a potential concern that the capacitors in the Standby Shutdown Facility (SSF) inverters would have to be replaced every 9 years to maintain the inverter seismic qualification. The licensee subsequently failed to take action to have the capacitors replaced prior to exceeding the 9-year replacement period which ended in 1992. The corrective action to replace the capacitors was scheduled to be completed on March 31, 1999 some 11 years after the PIP was initiated and 7 years after the first 9-year replacement interval ended. The PIP did not provide any technical justification for not replacing the capacitors. Section 3.1 of the UFSAR requires that all portions of the SSF required for mitigation of a seismic-induced turbine building flood shall be QA-1. Table 3-68 of the UFSAR identifies Wyle Lab Report 58456-1 (OM 346-0095) as the seismic qualification documentation reference for the SSF Inverters. This report requires replacement of the commutating and filter capacitors every 9 years to maintain the 40 year life requirements and seismic event specification of the inverters. The Operating Manual OM 320.-0118, Revision C also identifies that the commutating and filter capacitors are required

to be replaced every 9 years consistent with the qualification report. The fact that the 9 year replacement period was exceeded is in nonconformance with both the qualification report and the vendor technical manual. This nonconformance had not been identified or evaluated by the licensee as of December 1, 1998, some 6 years after exceeding the first 9-year replacement period. The inspectors did not consider the licensee's corrective actions for the PIP to be timely. The failure to replace the commutating and filter capacitors in the SSF inverters in a timely manner after exceeding the 9-year replacement period is a violation of 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, which requires that conditions adverse to quality, such as nonconformances be promptly identified and corrected. This will be identified as the first example of untimely corrective actions for EEI 50-269,270,287/98-11-07, Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions.

- PIP 0-O94-0678, Corrective Action 25 (assigned May 23, 1994) was to upgrade the Unit 3 normal sump line outside the reactor building to Duke Class B because it could potentially contain emergency sump radioactive recirculated water. As of December 1, 1998, the PIP indicated that this piping would not be upgraded until the Unit 3 refueling outage in the year 2000, over 5 years since originally assigned. PIP 0-O94-0678 was originally initiated to address Deviation 50-269, 270, 287/94-19-01, Improper Code Classification, which identified low pressure injection piping that was not in accordance with the Code Class requirements specified in the UFSAR. The need to upgrade the sump line piping referred to in Corrective Action 25 was determined by the licensee in a review conducted for other examples of misclassified piping. The inspectors considered the failure to upgrade this piping until year 2000 a untimely corrective action which is a violation of 10 CFR 50 Appendix B, Criterion XVI. This will be identified as the second example of untimely corrective actions for EEI 50-269,270,287/98-11-07, Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions.

- PIP 0-O95-0106, Corrective Action 4 (assigned January 30, 1995) was to replace damaged and missing cable sets required for one of two hydrogen recombiners maintained by Oconee. As of December 1, 1998, the PIP indicated that these cables had not been replaced. Oconee had two recombiners and by lease agreement was to have one available for two other utilities. Additionally, Oconee was required to have a recombiner available for its units, as specified by TS 3.16. While one recombiner may suffice for use among Oconee and the other two utilities, the approximately 4 years the corrective action had remained open was considered excessive by the NRC inspectors.

The above PIPs did not give any technical justification for the long delays in completing the corrective actions.

c. Conclusions

Apparent violation EEI 50-269,270,287/98-11-07, Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions, was identified. Two examples involved untimely corrective actions related to the resolution of PIP 4-088-0025 (Replace capacitors in the SSF inverters) and PIP 0-O94-0678 (Upgrade the Unit 3 normal sump line outside the reactor building to Duke Class B). The third example for this EEI involved inadequate corrective actions for a previous NRC violation and is described in Section E8.2 of this IR. The licensee initiated PIP

0-O98-5953 to address these findings. This apparent violation will remain open for a reasonable time to allow the licensee to develop corrective actions.

The PIP backlog categorized as Management Exceptions was not included in the licensee's scope, schedule, and goals for implementation of Recovery Plan Item SA1: Corrective Action PIP Activity Backlog. The inspectors concluded that implementation of the Management Exception backlog was not adequate because the criteria for Management Exception items did not consider priority based on the significance of the problem or technical justification as demonstrated by the untimely resolution of the PIPs reviewed during this inspection.

E2.5 HPI/LPI SITA System Review (Recovery Plan Item DB2)

a. Inspection Scope (37550,40500)

The inspectors reviewed the licensee's implementation of the High Pressure Injection (HPI)/Low Pressure Injection (LPI) Self-Initiated Technical Audit (SITA) System Review initiative N9701 to determine if it was consistent with the scope, schedule, and goals described in the Plan. This initiative was also reviewed for compliance with applicable licensee procedures.

b. Observations and Findings

The HPI/LPI SITA System Review was discussed in the Oconee Recovery Plan under the Management Focus Area of Design Basis. This initiative involved two phases. The first phase, which involved the licensee's performance of a reliability study of the HPI system, was reviewed and discussed under Recovery Plan item DB1 in NRC Inspection Report (IR) 50-269,270,287/98-10. The second phase involved the performance of an independent assessment of the HPI and LPI systems, which followed the format of the NRC Safety System Functional Inspection. The licensee performed the HPI/LPI SITA System Review under audit SA-97-10(ON)(SITA)(HPI/LPI). The inspectors focused on the second phase of the initiative during this current inspection.

The NRC had previously reviewed selected PIP reports associated with findings from audit SA-97-10(ON)(SITA)(HPI/LPI). The results of the previous NRC reviews were documented in NRC IRs 50-269,270,287/98-06 and 98-07. The inspectors reviewed the status of licensee corrective actions for the SITA findings assigned to engineering. Closeout of the SITA identified findings was being tracked via the PIP data base. The licensee had developed a plan and schedule to complete the initially identified corrective actions and the subsequent corrective actions. The licensee had established a target date of December 31, 1998, for completion of the 89 original corrective actions from the HPI/LPI SITA. The inspectors noted that only nine of the 89 corrective actions were still open. Six of the nine open corrective actions had due dates that were on or before the December 31, 1998, target date for completion of this initiative. The inspectors further noted that 26 of the 31 subsequent corrective actions had also been completed.

c. Conclusions

The inspectors concluded that the licensee's implementation of the HPI/LPI SITA System Review, which was the second phase of the HPI System Review initiative, was consistent with the scope and goals described in the Recovery Plan. Although all of the

original corrective actions were not completed by the December 31, 1998, target date, the remaining items had action plans and were scheduled for completion. This Recovery Plan item is closed.

E2.6 Configuration Management Project (Recovery Plan Item DB10)

a. Inspection Scope (37550, 92903)

The inspectors reviewed the licensee's implementation of the Configuration Management initiative N9811 to determine if it was consistent with the scope, schedule, and goals described in the Recovery Plan. This initiative was also reviewed for compliance with applicable licensee procedures.

b. Observations and Findings

The Configuration Management initiative was discussed in the Oconee Recovery Plan under the Management Focus Area of Design Basis. The stated purpose of this initiative was to identify, plan, staff, provide oversight, and focus on configuration management issues.

The inspectors reviewed the status of selected key milestones for this initiative. The milestone items reviewed included the following:

- performance of the calculation process assessment
- formation and staffing of a configuration management improvement team
- performance of a documents affected assessment
- implementation of interim measures to prevent engineering configuration management issues

The licensee completed the calculation process assessment (O-ENG-002-98) and initiated PIP 0-O98-3493 to track resolution of the assessment recommendations. The Configuration Management Improvement Team was formed, staffed, and a team charter developed. The Configuration Management Improvement Team charter included near term corrective actions (to be implemented by November 1, 1998) and longer term corrective actions. The licensee completed the documents affected assessment O-MOD-007-98. Actions from the calculation process assessment, PIP 0-O98-3493, and the documents affected assessment were assigned to the Configuration Management Improvement Team for resolution. The interim measures to prevent engineering configuration management issues had been implemented.

The inspectors also noted that selected actions from the borated water storage tank (BWST) root cause evaluation (PIP 0-O98-0707 and related LER 50-269/98-04) had been assigned to the Configuration Management Improvement Team. One of the actions that had been a primary focus of the Configuration Management Improvement Team since its formation was the team's involvement in reviewing the licensee's calculation data base in order to identify the safety-related risk significant historical calculations which will require further review.

During review of the Recovery Plan milestones, the inspectors noted that some of the milestones had not been implemented as planned. Some of the near term corrective

actions defined in Revision 2 of the Configuration Management Improvement Team charter were not completed by the November 1, 1998, date specified in the charter. Also, other near term actions were deleted by later revisions to the charter. The Recovery Plan indicated that one of the criterion used to measure success of this initiative was completion of the near term corrective actions in the Configuration Management Improvement Team charter. In addition, some of the measures previously implemented to prevent Engineering configuration management issues had been discontinued.

c. Conclusions

The licensee's implementation of the Configuration Management initiative was not consistent with the scope, schedule, and goals described in the Recovery Plan. All of the near term corrective actions defined in Revision 2 of the Configuration Management Improvement Team charter were not completed by the November 1, 1998, date specified in the charter; and some of the measures previously implemented to prevent Engineering configuration management issues had been discontinued.

E2.7 Followup on the Keowee Test Results

a. Inspection Scope (37550, 92903)

The inspectors followed up on PIPs generated during performance of the one-time design verification test conducted on the emergency power supply (Keowee) during November 1998. The followup encompassed problems specifically discussed as IFI 50-287/98-10-07: Followup on Valve 3LP-17 Erratic Current Trace.

b. Observations and Findings

Contractor Chattering Problem

As discussed in NRC IR 98-10, the starter (contractor) for valve 3LP-017, Low Pressure Injection System injection valve, exhibited erratic behavior during the first portion of the special Keowee test. The 3LP-017 valve circuit was one of nine valve circuits whose current was being monitored by digital recording instrumentation. The valve went to its correct position during the test. No problem could have been seen except through review of the current traces after completion of the test. The licensee was using their FIP to determine the root cause and corrective actions for this problem. The inspectors discussed the progress of the FIP with the team leader and one team member.

To date, the FIP has determined through examination of the current traces that the contractor initially picked-up at about 75 percent of nominal system voltage with the contacts of all three phases closing to start rotating the valve motor. The motor starting transient period lasted a little over a second. During the transient period, phase C current dropped to zero, then increased and decreased erratically at levels well below the current of phases A and B. The behavior of phase C current was probably due to phase C contact chattering. The increasing voltage had reached about 87 percent when the motor starting transient ended. Phase C contact remained open, and the valve continued to travel to the open position with only phases A and B carrying current (i.e. single phased). During pre-test operability valve stroking and the second portion of the test, the contractor for valve 3LP-017 behaved normally.

During a similar test conducted in January 1997, valve 3LP-017 exhibited very similar behavior, except that by the time voltage reached normal steady state levels the contacts of all three phases were closed. The analysis at that time concluded that contact chatter was a result of initially energizing at sub-rated voltage levels, but as long as all three phases eventually closed in solid there would be no adverse effects on overall system operation. This conclusion was based in part on the fact that valve torque and thrust calculations took no credit for the hammer blow effect and in fact assumed a five second motor stall. The valve calculation methodology was confirmed by the inspectors.

Other relevant facts determined by the FIP team were:

- The resistance of the contractor coil as compared to other similar coils did not indicate shorted turns.
- The inductance of the coil was slightly low as compared to other similar coils.
- The coil had small crack in the case.
- One other valve exhibited chattering of a contact with all three contacts finally closing.
- Examination of a sample of contractor shows that de-energized contact gap will vary among the three contacts of a particular contractor. Since the contacts are spring loaded, the gap differential should be taken up when the contractor solidly pulls in. However, marginal (not solid) pick-up could mean contact make without full spring compression. In this case, the contact with the largest gap of the three would be the most likely to chatter. Examination of the contacts on the 3LP-017 contractor showed that the phase C contact had the largest gap of the three. The gap differential was seen by the inspectors when they examined a sample of contractor.

The preliminary conclusion of the FIP team was that the problem of phase C contact failing to close on valve 3LP-017 after normal voltage was reached was caused by a weak contractor coil. This theory fit the known facts and was the most likely of the potential causes put forth by the team. Therefore, the next step of the investigation was to analyze the coil to determine whether it really was a weak coil (i.e., one capable of producing only a fraction of the design pull-in force). The licensee plans to do this by sending the contractor to the manufacturer's test laboratory or equivalent. The FIP team will also verify that the control circuit voltage drop for this circuit is not an outlier as compared to the other valve circuits.

One corrective action already included in the PIP report was to investigate the possibility of improving the voltage dip which occurs during the transfer to the Keowee power source during design basis events. It appears that a significant contributor to the voltage dip is the starting of the reactor building cooling units. It will be investigated whether the starting of the reactor building cooling units can be delayed such that they would not start simultaneous with the various valve contractor being energized to achieve an improvement in voltage dip seen by the contractor.

The inspectors were aware that the licensee had a project to replace all the motor starters due to a problem with the auxiliary contacts. While this program was scheduled to begin in the near future, completion was projected several years into the future.

Field Flash Breaker Cycling

The licensee investigated the field flash breaker cycling described in NRC IR 50-269,270,287/98-10. Through study of the sequence of events recorder printout, one can see that the field flash breaker cycled during the frequency overshoot period of the first part of the test. It did not cycle at the point of load application (i.e., the 90 percent voltage point). It did not cycle during the second part of the test. Two modifications are planned which should eliminate the concern with field flash breaker cycling during Keowee startup; installation of new voltage relays which will operate independent of frequency and installation of new circuit breakers which should be immune to tripping free when subjected to cycling. The relays are scheduled to be installed in spring 1999. This modification, by itself, may completely resolve the concern, because the set point will probably be something less than 90 percent voltage.

Review of PIPs

The inspectors requested and reviewed two summaries of PIPs:

- All PIPs generated from November 18, 1998, to December 7, 1998, containing the words "ES Test", "Keowee", "Engineered Safeguards" and "TT 610/030."
- All PIPs generated from November 18 to 24 (inclusive), 1998. This summary bracketed the time period of the test and a few days beyond.

The summaries were selected by the inspectors to ensure that all PIPs generated as a result of the special test were reviewed. Review of these summaries by the inspectors revealed all the significant PIPs had been reviewed, and no additional PIPs were selected for detailed review.

c. Conclusions

The licensee was resolving through the PIP and the FIP all the potential problems brought to light by conducting the special test on Keowee in November 1998. The most significant problem was the chattering with one phase failing to close of one of the nine contractor that were monitored during the test. The FIP team had found the most probable cause to be a weak contractor coil. However, this finding was preliminary and more work was needed to confirm the cause. This completes the followup on the contact chatter documented in IFI 50-287/98-10-07. This IFI is closed.

E7 Quality Assurance in Engineering Activities

E7.1 PIP Quality Improvements - Root Cause Quality (Recovery Plan Item SA2)

a. Inspection Scope (37550, 40500)

The inspectors reviewed the licensee's implementation of initiative N9834, associated with raising the quality of root cause analysis, to determine if the implementation was consistent with the scope, schedule, and goals described in the Plan.

b. Observations and Findings

This initiative is discussed in the Oconee Recovery Plan under the Management Focus Area of Self Assessment. This initiative included the establishment of a tool to measure

root cause performance and an action plan to improve performance. In the first quarter of 1998, the licensee implemented a 16-point quality check list as a tool to measure the quality of root cause performance on level one and two PIPs. The quality check included eight elements to be assessed in each root cause analysis and established a 90 per cent quality performance goal based on this 16-point assessment.

The initiative referenced a Root Cause Improvement Action Plan to improve root cause performance. The action plan, item five, referenced in the initiative specified a trending and feedback process and the establishment of a management level Corrective Action Review Board (CARB) to review a small sample of root cause evaluations in addition to the 16 point quality check performed by the Safety Review Group (SRG).

Although the quality check tool was implemented, the feedback process referenced in the action plan was not implemented. The action plan specified that data would be maintained on the quality check scores, scores of less than 13 would be returned for revision, and feedback would be provided to root cause investigators. There was no information to support data or trending on quality check scores. The third quarter scores included approximately seven scores less than thirteen, none were returned for revision. The inspectors reviewed the third quarter 1998, quality checks and interviewed the root cause investigators. Only one in ten investigators assessed by the quality check had received any feedback and the remaining were not familiar with the elements included in the root cause quality check list.

Another root cause improvement initiative item not met was related to the activities of the CARB. The action plan included the charter and establishment of the CARB to provide a high level management review of a small number of root cause analyses. The criteria of the CARB charter, dated July 1, 1998, specified monthly meetings to review two to four root causes each. Charter identified CARB members included the site vice president, plant manager, engineering manager, safety assessment manager, and SRG manager. The CARB had not met the monthly frequency stated in the charter. The first meeting was conducted on September 10, 1998, at which there were two root causes reviewed. The site vice president, station manager, and engineering manager were not present at this first meeting. The second meeting was on November 9, 1998, addressed two root cause analyses, and was attended by the majority of charter identified CARB members.

The licensee had not achieved the established goal of the recovery plan item after three quarters of implementation of the quality checks. The established goal was a 90 per cent quality performance level based on the 16 point score. The October 5, 1998, status update on this Plan item stated that the quality scores were 88 per cent, 82 per cent, and 88 per cent for the first through third quarters with a yearly average of 86 percent.

c. Conclusion

The licensee's implementation of the PIP root cause quality improvement initiative (N9834) was not consistent with the scope, schedule, and goals described in the Recovery Plan. Although the quality check measuring tool was implemented in early 1998, the action plan items to use this tool effectively to improve quality had not been implemented. This recovery plan item remains open for further review.

E7.2 Manager Observation/Group Assessment Effectiveness and Benchmarking (Recovery Plan Item SA3)

a. Inspection Scope (37550, 40500)

The inspectors reviewed the licensee's implementation of Manager Observation/Group Assessment Effectiveness and Benchmarking initiative N9731 to determine if it was consistent with the scope, schedule, and goals described in the Recovery Plan. This initiative was also reviewed for compliance with applicable licensee procedures.

b. Observations and Findings

This initiative is discussed in the Oconee Recovery Plan under the Management Focus Area of Self-Assessment. The purpose of this initiative was to increase the number and raise the quality of manager observations, group self-assessments, and benchmarkings such that trending and feedback could be used to help the station improve. The inspectors reviewed the schedules and selected reports for manager observations, group self-assessments, and benchmarkings performed in 1998. The inspectors also reviewed selected manager observations performed in 1997.

The requirements and guidelines for performing manager observations and group self-assessments were specified in the licensee's NSD 607, Self-Assessments, Revision 4. The inspectors reviewed the manager observation logs and a sample of approximately 75 manager observations that were completed during the period from September 1997, to October 1998. The inspectors noted that the manager observations were generally completed within the time and guidelines specified in NSD 607 and they met the goals of the Recovery Plan regarding the number and percentage of manager observations to be completed each quarter. The manager observation reports reviewed contained no significant findings. The inspectors noted that items which warranted further management attention were documented in the manager observation reports. Although the manager observation reports documented items needing further attention, it was not clear from the observation reports as to how the items were dispositioned.

The inspectors reviewed three licensee self-assessments of the Manager Observation Program. The self-assessments were performed in 1998 and included two manager observation reports and a SRG assessment SA-98-39(MC)(SRG). The two manager observation reports were performed at the Oconee Nuclear Station (ONS) and assessment SA-98-39(MC)(SRG) was a combined effort performed at all three of the Duke Power nuclear sites. These self-assessments, which were completed prior to this NRC inspection, were performed to assess the effectiveness of the Manager Observation Program. The self-assessments identified a number of weaknesses and areas for improvement in the Manager Observation Program. The licensee initiated PIP 0-M98-2254 to address the findings and recommendations identified in assessment SA-98-39(MC)(SRG). Items noted by the inspectors during their review of the manager observation reports were consistent with findings identified in the self-assessments. The licensee was taking actions to address the findings from the self-assessments. Actions being taken included a revision to NSD 607 to incorporate the recommendations from PIP 0-M98-2254 and the self-assessments.

The inspectors reviewed the group self-assessment logs and selected self-assessment reports for activities performed in 1998. During this review, the inspectors noted that the licensee met the overall goals of the Recovery Plan regarding the number and percentage of group assessments to be performed each quarter. However, SRG

documentation indicated that the licensee did not follow the requirements of procedure NSD 607, in that, some groups did not perform at least one self-assessment per quarter. The licensee initiated PIP 0-O98-5959 to address this issue. The inspectors discussed this item with licensee personnel and indicated that this failure to follow procedures constituted a violation of minor significance and is not subject to formal enforcement action. The inspectors noted that, while some station groups did not meet the requirements for performing at least one self-assessment per quarter, other groups such as Maintenance and Commodities and Facilities had far exceeded the goal of one self-assessment per quarter.

The inspectors reviewed the licensee's schedule and selected reports of visits to several utilities where various activities were benchmarked in 1998. The reports provided feedback on the activities observed and highlighted strengths to be considered for possible implementation at Oconee. The benchmarking efforts provided the licensee with the intended feedback results.

c. Conclusions

The inspectors concluded that the licensee's implementation of initiative N9731 was, in general, consistent with the scope, schedule, and goals described in the Recovery Plan for Manager Observations and Group Assessments. Although the number of manager observations and group self-assessments have increased, the licensee's efforts to improve the quality were continuing. The manager observations reviewed by the inspectors contained no significant findings. Revisions to procedure NSD-607, which are intended to address some of the weaknesses in the manager observation process that were identified by the licensee, are scheduled to be implemented in early 1999.

The inspectors also noted that SRG documentation indicated that procedure NSD 607 was not followed, in that, some station groups did not perform at least one self-assessment per quarter in 1998. This failure to follow procedure NSD 607 constituted a violation of minor significance and is not subject to formal enforcement action.

Benchmarking efforts were consistent with the Recovery Plan and provided licensee management with the intended feedback results.

E7.3 In-plant Review/SRG Job Observation Program (Recovery Plan Item SA4)

a. Inspection Scope (40500)

The inspectors reviewed the implementation of this Oconee Recovery Plan initiative N9833, which was associated with improving the structure of the Independent Nuclear Oversight Team (INOT), to determine if implementation was consistent with the scope, schedule, and goals described in the Plan. The purpose of the initiative was to improve the self-assessment capability of the SRG.

b. Observations and Findings

The implementation of this initiative was previously reviewed in August, 1998 (NRC IR 50-269,270,287/98-08). The initiative remained open pending development of station procedures and directives establishing the roles and responsibilities of the INOT. Previously the INOT was using the Catawba Nuclear Station guidance document for the INOT. Additionally, the INOT team was not fully staffed in that the operations team position was vacant. The operations team member's responsibilities were assumed by

the maintenance team member. The November 5, 1998, update of this recovery plan item stated that the status of the INOT team on these two deficiencies remained the same. The SRG manager indicated these deficiencies would be resolved in the first quarter of 1999.

During this inspection, the inspectors reviewed INOT products which included in-plant reviews (IPRs), and other job observation mechanisms. The INOT self-assessment reports demonstrated appropriately detailed and independent assessments of the activities observed. The team members were dedicated and knowledgeable in the activity areas reviewed. The IPRs were documented in PIPs and the team recommendations were established as corrective actions of the PIPs. There had not been a large number of self-assessments performed. During the weekly INOT meeting attended by the inspectors, the schedule was revised to delete and reschedule previously planned assessments. However, the recovery plan required no specific number of assessments and the SRG manager stressed quality over quantity.

The inspectors reviewed the 1998 monthly reports provided by the INOT to management. In general, these reports reflected the findings from the INOT self-assessments. The inspectors noted three findings from IPRs that were not addressed in the monthly reports. These included negative findings associated with equipment mis-positions (SA-98-114), material condition practices in the reactor building equipment (SA-98-113), and achievement of Unit 2 end of cycle 16 (2EOC16) refueling outage milestones (SA-98-96). The SRG manager indicated that it was the discretion of the INOT to determine the information provided in the monthly report and that the above negative findings were below the threshold for inclusion in the monthly reports. The inspectors discussed this issue with the station upper management to determine if the report contents met the management expectations. Station management indicated that the SRG discretion on these issues was appropriate.

c. Conclusion

The implementation of the INOT was not consistent with the schedule described in the Recovery Plan. Full team membership and incorporation of the present informal guidance into station directives was anticipated for the first quarter of 1999. However, the INOT was achieving its self-assessment function and management reporting role, therefore the scope and goals of this recovery plan item were being met. Recovery Plan Item SA4 is closed.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) IFI 50-269,270,287/95-26-01: Region II Review of NRC Headquarters Special Report

The inspectors read a report titled "Final Report Emergency Electrical Power System and Other Related Matters Oconee Nuclear Station , Units 1,2 and 3", which was generated by the Office of Nuclear Reactor Regulation. The inspectors read the report after it had received almost all the reviews and concurrences at NRC Headquarters, but it was still technically preliminary and had not been issued. The inspectors found that the report addressed all the issues that remained open from the 1993 Electrical Distribution System Functional Inspection. Specifically, it addressed the performance of the Keowee units with regard to providing adequate voltage and frequency during starting and running, the capacity of the make-up pump in the standby shutdown facility, and single failure criterion issues. The single failure issues were addressed by probabilistic risk

assessment techniques. There were no action items for Region II contained or implied by the report except what would be addressed by the routine inspection program.

E8.2 (Closed) VIO 50-269,270,287/97-14-04: Failure to Implement Vendor Recommendations for DB-25 Circuit Breakers

The inspectors confirmed that the maintenance procedure for the DB-25 circuit breakers had been revised to include the missing vendor recommendation in October 1997. A supplementary response to the violation, dated January 21, 1998, stated the following: "A re-review of seven procedures related to QA-1 metalclad power circuit breakers against the associated vendor instruction books concluded that the procedures are technically acceptable as written and that no critical vendor maintenance has been omitted." The response also stated that the problem described in the violation was an isolated case. The inspectors discussed the methodology and findings with the engineers who performed this review. The inspectors made an independent review of one maintenance procedure selected at random from the list of seven reviewed by the licensee. The procedure reviewed by the inspectors was IP/O/A/2001/003A, 4.16 kV [kilovolt] & 6.9 kV ACBs. Records showed that the licensee reviewed this procedure against a vendor manual having Oconee Number OM-302-681. When the inspectors requested a copy of procedure 003A and the associated vendor manuals to perform their review, the licensee furnished a vendor manual having Oconee Number OM-302-105, which was referenced in the procedure. The 681 manual is the vendor installation/maintenance instruction manual for 4.16 kV circuit breakers. The 105 manual contained the vendor installation and maintenance instruction manual for 6.9 kV circuit breakers. The licensee should have reviewed both the 105 and 681 manuals, rather than just the 681 manual, during the re-review mentioned above. The inspectors reviewed maintenance procedure 003A against both of the vendor manuals, specifically looking for where the two vendor manuals differ.

One problem was identified by the inspectors. Step 10.24 of the 003A maintenance procedure specified checking the gap between the control device lever and the limit switch crank, and gave acceptance criteria 0.06 to 0.09 inches with the closing springs charged. This was consistent with the vendor manual for 4.16 kV circuit breakers or the 681 manual. The inspectors identified that the vendor manual for the 6.9 kV circuit breakers had a different criteria for this check: 1/64 to 1/32 inches. The manufacturer's number and title of this manual are: IB 6.2.2.7-1G, Installation/Maintenance Instructions Medium-Voltage Power Circuit Breakers 7.5HK500 1200 - 3000A. The manual was received on March 27, 1997, and the licensee's vendor manual was updated on April 2, 1997. The licensee's re-review of vendor manuals mentioned above took place in October 1997 or later. The licensee presented evidence that previous versions of the manufacturer's instruction book for 7.5HK500 circuit breakers contained the same clearance criteria as in the book for 4.16 kV circuit breakers, which was consistent with the maintenance procedure. The licensee contacted the manufacturer and learned that the reason for the change in recommended clearance on the 6.9 kV circuit breakers related to aging/wear concerns. The manufacturer knew of no cases where adherence to the originally specified clearances resulted in spurious tripping or failure to trip on demand. At Oconee, the 6.9 kV circuit breakers were in Maintenance Rule status A2, which was an indication that these breakers had been performing well. The licensee generated a PIP, and concluded within that PIP that there was no immediate operability concern arising out of the revised clearance criteria. Proposed corrective action for the PIP included verifying that a procedure change was required, and if necessary, making that change. In addition, the licensee stated that they recently initiated a program to revise the circuit breaker maintenance procedures to incorporate more detail for the

individual steps. This program would necessarily entail another review of the vendor manuals and generic communications on circuit breakers. The inspectors agreed with the operability conclusion of the PIP and the proposed corrective actions.

Consideration of the circumstances described above leads to the conclusion that it did not appear that the licensee reviewed the revised vendor manual (IB 6.2.2.7-1G) for changes applicable to their program when it was received in March 1997. Therefore, the change in control device gap was not identified. The re-review conducted as part of the corrective action for a violation involving lack of implementation of vendor maintenance recommendations was another opportunity to identify the gap criteria change. However, the 6.9 kV manual was not reviewed, but only the manual for 4.16 kV was reviewed at that time. The inspectors also noted that the re-review of vendor manuals to determine extent of condition related to the violation was not contained in the first response to the violation, but was added to the corrective actions only after intervention by the NRC. The circumstances described above represent a violation of 10CFR50, Appendix B, Criterion XVI, Corrective Action, in that the corrective actions implemented for the violation were not adequate to accomplish the desired result. This issue will be identified as one example of inadequate corrective actions in EEI 50-269,270,287/98-11-07, Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI, Corrective Actions. The other two examples for this EEI involve untimely corrective actions and are described in Section E2.4 of this IR. The licensee initiated PIP 0-O98-5953 to address these findings. This EEI will remain open for a reasonable time to allow the licensee to develop corrective actions.

E8.3 (Closed) IFI 50-269,270,287/97-18-06: K-Line Breaker Issues

This item addressed licensee identified equipment performance deficiencies on Asea-Brown Boveri (ABB) K-Line 600 volt load center OXSF breakers. These deficiencies included potential re-latch failure due to grease hardening on mechanical sub-components and set point drift on over-current trip devices and were identified during preventive maintenance. The inspectors identified this follow-up item to review the licensee's corrective action and evaluation of station impact.

These issues and corrective actions were documented on PIPs 98-515 and 98-516 dated February 3, 1998, and PIP 98-616 dated February 6, 1998. The K-Line breakers have been in a refurbishment cycle which was initiated in 1993 to be completed in 1999. Interim actions on these breakers included cleaning and replacing the lubricant. The over-current trip set point drift was determined to be the result of aging and all of the identified susceptible devices were replaced. The operability evaluation documented in the PIPs determined that there was no plant impact since the breakers normal and accident position was the closed position. There have been no additional ABB K-Line 600 Volt breaker performance problems since the corrective actions were completed.

E8.4 (Closed) VIO 50-269,270,287/98-03-02: Failure to Perform Penetration Room Ventilation System (PRVS) Surveillance in Accordance with Technical Specifications (TS)

(Closed) LER 50-269/98-10: Test Method Does Not Meet Technical Specification Requirement Due to Inadequate Wording of Licensing Submittal

(Closed) NOED 98-6-011: Notice of Enforcement Discretion for Duke Energy Corporation, Oconee Units 1,2, and 3, Regarding TS 4.5.4.1.b.1

These items addressed refueling outage periodic surveillance testing of the PRVS per TS 4.5.4.1.b.1, which was not accomplished as specified by the TS and referenced industry standard ANSI N510-1975. The specified test method for flow capacity testing was a traverse pitot tube velocity pressure measurement. The licensee's test method to meet this TS was by a fixed orifice differential pressure (dp) method. There was no testing performed which verified the orifice dp method was equivalent to the pitot tube method nor a documented evaluation or justification for the alternate method. LER 50-269/98-10 was submitted to address the potential operability concern of the PRVS due to testing by a method different than specified by the TS. The corrective actions stated in the LER were identical to those specified in the licensee's August 5, 1998, response to the violation. These actions included PRVS flow testing by the TS specified traverse pitot tube method and associated system modifications to accomplish this testing. Additionally, the corrective actions included a review of the TS for consistency with referenced industry ventilation and filtration standards and training on the relationship between operability and surveillance requirements.

The inspectors observed PRVS flow capacity testing performed in August 1998, and reviewed the test results on all PRVS trains. The results were documented on TT/1/A/0110/019, PRVS 1A, 1B, 2A, 3A, and 3B, dated August 6, 1998. With the exception of the train 3B test, all flows were consistent with the TS criteria. The 3B flow was adjusted with the discharge damper and an operability evaluation determined that the system function was not impacted by the slightly higher flow rate. The training and TS reviews were scheduled for completion in January 2, 1999, and included as corrective actions in PIP 98-3420, dated July 6, 1998. Based on completed and scheduled corrective actions, the inspectors concluded that this item was adequately resolved.

The inspectors reviewed NOED 98-6-011 to determine if there were additional regulatory issues and concluded that no additional enforcement action was warranted.

The inspectors concluded that the corrective actions taken by the licensee to resolve Violation 50-269,270,287/98-03-02; LER 50-269/98-10; and NOED 98-6-011 were adequate.

E8.5 (Open) LER 50-269/98-06: Inadequate Safety Evaluation Results In Operating Outside the Design Basis of the Plant

a. Inspection Scope (92903)

The inspectors reviewed LER 50-269,270/98-06 and associated Nuclear Station Modification (NSM) ON-53046/00, PIP 0-O98-1165 and other documentation related to the licensee's corrective actions for this LER.

b. Observations and Findings

This LER documents an event where a 1984 modification separated the combined Unit 1 and 2 control room ventilation system (CRVS) from the Unit 1 and 2 cable and equipment rooms, introducing a single failure vulnerability in each units cable room cooling system, which upon failure of a single fan, could have resulted in redundant safety-related electrical breakers tripping as a result of high room temperatures. As a consequence, safety-related equipment and equipment important to safety required to mitigate a design basis accident could have been lost, including 125 volts direct current (VDC) vital instrumentation and control (I&C) power, 120 volts alternating current (VAC)

vital I&C power, 120 VAC essential power, 208/120 VAC safety power, and all ES systems. Section 3.11.4 of the UFSAR required that redundant air conditioning and ventilation equipment be provided for the control area to assure that no single failure of an active component would prevent proper control area environmental control. The cause of the nonconformance with the UFSAR was due to an inadequate 10 CFR 50.59 Safety Evaluation for the 1984 modification. This event was discussed in Section E1.1 of IR 50-269,270,287/98-03 and identified as apparent violation EEI 50-269,270/98-03-04, USQ Involving Single Failure Vulnerability Introduced by 1984 CRVS Modification.

In response to this event, the licensee issued PIP 0-O98-1165 and took immediate corrective actions to assess operability of the CRVS, entered TS 3.0 on Units 1 and 2 until compensatory actions were put in place, notified the NRC pursuant to 10 CFR 50.72, and issued a procedure for compensatory actions. All of these earlier corrective actions were discussed in Section E1.1 of IR 50-269,270,287/98-03. Other required corrective actions were outlined in the LER as follows:

(1) Perform the appropriate modifications to the cable and equipment room cooling system to resolve the non-conformance with the UFSAR Section 3.11.4.

(2) Complete the UFSAR Accuracy Review Project to verify that the UFSAR is consistent with existing plant design, configuration, and operation.

(3) Revise the UFSAR to include the control area cooling single active failure criterion in Section 9.4.

(4) Revise the design basis document to adequately address the control area cooling single active failure criterion.

(5) Complete a single active failure analysis of the control area cooling.

The inspectors found that corrective actions (CA) 1, 3, and 5 had been completed satisfactorily. Regarding CA Number 1, the licensee implemented modification NSM ON-53046/00. This modification enabled a flow path to be established between the Units 1 and 2 cable and equipment rooms so that either Units 1 or 2 cable room air handling unit (i.e., AHU 1-34 or 2-35) could provide cooling to both of the Units 1 & 2 cable rooms upon loss of a single cable room fan. The inspectors reviewed the final scope document for NSM ON-53046/00, Revision 1, and the associated 10 CFR 50.59 Safety Evaluation, both dated July 29, 1998, and found that they both adequately described the changes and that no unreviewed safety questions were involved which would have required prior NRC approval. Portions of the completed modifications were walked down and found to be satisfactorily installed. The post-modification test results were found to meet acceptance criteria. Appropriate retesting had been performed to resolve all test anomalies.

With respect to CA Number 3, the licensee revised Section 9.4 of the UFSAR and added a statement regarding the control area cooling single active failure criterion.

Regarding CA Number 5, the licensee performed Calculation OSC-7183 (dated May 28, 1998) which was a review of the control room ventilation and chilled water systems for single active failures which could potentially prevent the systems from performing their functions. Also Calculation OSC-7190 (dated July 14, 1998) evaluated the failure modes and effects of the changes made to the CRVS by Modification NSM ON-53046/00.

The inspectors found that CA Number 2 was still in progress and was scheduled to be completed around March 1999.

With respect to CA Number 4, Design Basis Specification OSS-0254.00-00-1021 had been revised to incorporate the single failure design requirement for the CRVS. However, the inspectors noted while reviewing the revised specification that Section 20.2.9 incorrectly stated that the CRVS was not required to withstand single failures. This statement was cited as the basis for not requiring electrical separation. After being informed of this discrepancy, the licensee initiated PIP 5-098-5756. This issue remains open pending resolution of the above PIP.

Other corrective actions related to this event were identified in the licensee's response to NRC Violation EA 98-199-01014 by letter dated July 6, 1998; Subject: Reply to Notice of Violation. These corrective actions have been reviewed and are discussed in Section E8.6 of this IR.

c. Conclusions

LER 50-269,270/98-06 remains open pending completion of the UFSAR Accuracy Review Project and the resolution of an issue to determine if electrical separation is required for CRVS to meet the single failure criterion.

E8.6 (Open) Violation EA 98-199-01014 (previously identified as EEI 50-269,270/98-03-04): Unreviewed Safety Question Involving Single Failure Vulnerability Introduced by a 1984 Control Room Ventilation System Modification

a. Inspection Scope (92903)

The violation involved a 1984 modification that introduced a single failure vulnerability in the CRVS that could have potentially resulted in the common cause failure of redundant safety-related equipment required for accident mitigation. The LER (50-269,270/98-06) for this event was reviewed and is discussed in Section E8.5 above. This review looked at those specific corrective actions that were identified in the licensee's response to the violation dated July 6, 1998.

b. Observations and Findings

The licensee responded to this violation by letter dated July 6, 1998, Subject: Reply to Notice of Violation. The violation was caused by the failure of the individuals involved to review all applicable sections of the UFSAR during the performance of the 10 CFR 50.59 evaluation for the control area ventilation system modification. Other contributing factors were: inadequate guidance for performing 10 CFR 50.59 evaluations; lack of formal training on performing 10 CFR 50.59 evaluations; and the fact that the emphasis in the 1984 time frame concerning the review of non-safety systems was for the effects of the non-safety system on safety related systems. The inspectors found that the corrective action to revise CRVS Specification OSS-0254.00-00-1021 to incorporate control area cooling single failure requirements was not implemented correctly. These changes were incorporated by Revision 5 to the specification. While reviewing this document (Revision 5), the inspectors noted that Section 20.2.9 incorrectly stated that CRVS was not required to withstand a single failure. This statement was the supporting basis for not requiring electrical separation of the CRVS. The licensee initiated PIP 5-098-5756 to resolve the problem. The other remaining corrective actions stated in the response had been completed satisfactory. This included training of appropriate personnel on this

event; implementing a modification to resolve the CRVS single active failure non-compliance; and enhancing the SITA process procedure to require that 50.59s for past modifications be reviewed during assessments.

As part of this review, the inspectors requested training records for 4 Qualified Reviewers. The individuals were selected from the ONS Qualified Reviewers List dated November 4, 1998. The training records were for two courses, 10 CFR 50.59 Evaluation Training and Qualified Reviewer Training. The licensee could not locate the Qualified Reviewer training record for one of the individuals selected from the Civil, Electrical and Nuclear Engineering Department. Upon further review, the licensee determined that this individual had not completed all the required Qualified Reviewer training and should not have been included on the Qualified Reviewers List. The licensee indicated that a similar problem with non-qualified individuals on the list had been identified with individuals from the Maintenance and Work Control Department. The latter problem had been identified in PIP O-098-4769 dated October 13, 1998. The PIP was still open awaiting completion of the corrective actions.

Nuclear Station Directive 110, Revision 4, requires under minimum qualification and training criteria that qualified reviewers shall have successfully completed Technical Review and Control training. The failure to assure that the individual involved had completed the training prior to being placed on the Qualified Reviewers List is a violation of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures, and Drawings. The inspectors concluded that it is very likely that the licensee would have identified and corrected this problem as part of the corrective actions for PIP O-098-4769. Therefore, consistent with Section VII.B.1 of the NRC Enforcement Policy this item will be identified as NCV 50-269,270,287/98-11-08: An Individual was Incorrectly Placed on the Qualified Reviewer's List Without Completing all Required Training.

c. Conclusions

A non-cited violation was identified for incorrectly placing an individual on the Qualified Reviewers List without having completed the required training. Violation EA 98-199-01014 remains open pending resolution of an issue to determine if electrical separation is required for CRVS to meet the single failure criterion.

E8.7 (Closed) VIO 50-269,270,287/98-05-01: Inadequate Corrective Actions for Recurring Problems With Engineering Instructions for Minor and Temporary Modifications

a. Inspection Scope (92903)

The inspectors reviewed the licensee's response to this violation dated July 1, 1998, to verify that corrective actions were being completed in accordance with the response.

b. Observations and Findings

The violation response identified the root cause of the violation as inattention to detail. The licensee initiated PIP 0-O98-2952 to identify and track the corrective actions for this violation. The inspector reviewed selected corrective actions that had been completed or were in progress. These actions included the following:

- NSD 223, Trending of PIP Data, was communicated to PIP coordinators during April 1998 training.

- Engineering personnel had received instructions concerning the required quality assurance review per the modification process.

- Engineering instructions governing the minor modification and temporary modification processes were being revised to require a review by the modification's qualified reviewer as to whether a QA review would be required.

In addition to the above corrective actions, the inspector held discussions with PIP coordinators in the Engineering department and noted that the PIP coordinators were knowledgeable of their responsibilities as work group trend evaluators and of the requirements for trending PIP data specified in NSD 223. The inspector also reviewed selected engineering work group trend reports to verify that the PIP data was evaluated and documented in accordance NSD 223. The inspector noted that PIP 0-O98-2952 identified time pressure as a justifiable contributing factor to the root cause of this NRC violation. Corrective action number 10 for PIP 0-O98-2952 was assigned to investigate time pressure as an adverse impact on other engineering tasks in addition to modifications. Engineering self-assessment O-ENG-009-98, Indication of Time Pressure in Engineering, was performed to address CA number 10 in PIP 0-O98-2952. This assessment investigated the history of time pressure as associated with engineering activities in general. The self-assessment recommended that its findings be presented to the engineering management team via the Engineering Corrective Action Review Board (ECARB) to discuss previous corrective actions and determine if additional actions need to be taken. The next ECARB meeting was scheduled for January 25, 1999.

c. Conclusion

The inspector concluded that the licensee's corrective actions implemented to address NRC violation 50-269,270,287/98-05-01 were adequate.

E8.8 (Closed) URI 50-269,270,287/98-07-04: IST Program and Design Control Process Interface

a. Inspection Scope (92903, 37550)

This URI was identified pending further NRC review of the interface between the IST program and design control process. The adequacy of this interface had been questioned by the NRC as a result of findings identified by the licensee in audit SA-97-10(ON)(SITA)(HPI/LPI). The audit findings were documented by the licensee for disposition in PIP reports. The findings involved deficiencies in the translation of design information from modifications and calculations to the IST program.

The inspectors further reviewed the interface between the licensee's IST program and design control process by re-examining the related licensee findings and corrective actions, and discussing the issues with licensee design and IST personnel. The NRC inspectors previously established that the pumps and valves in these licensee findings had been operable (Inspection Reports 50-269, 270, 287/98-06 and 98-07).

b. Observations and Findings

PIP 0-O98-0159, dated January 13, 1998, identified that the minimum head curve requirements from calculations were not correctly reflected in the IST alert and required action ranges for low pressure injection (LPI) and HPI pumps. The PIP reported that this problem was found to have existed for years. The inspectors found that the PIP

specified appropriate corrective actions for the LPI and HPI pumps and that most of the actions were reported to be complete.

The PIP did not indicate that an extent of condition review had been performed to determine whether similar problems existed for pumps in other systems. When this was questioned by the inspectors, the licensee stated that the system engineers had been surveyed and indicated that the problem did not extend to any other systems. In addition, the licensee stated that a PIP would be initiated to document reviews performed by the system engineers to verify that pumps in other systems were not affected.

PIP 0-O98-0165, dated January 13, 1998, identified that calculation OSC 2820, "Emergency Procedure Guidelines Setpoints," Revision 12, had used LPI valve IST stroke times as input limitations; but that the IST database and LPI design basis document (DBD) now indicated there were no design stroke time limits for the valves. Further, the current measured stroke times of LPI valves LP-21 and -22, which had been modified subsequent to preparation of OSC 2820, Revision 12, exceeded the input values demonstrated acceptable in OSC 2820. As corrective action, PIP 0-O98-0165 specified that OSC 2820 would be revised to incorporate conservative stroke time limits for the LPI valves and that the DBD would be updated. These revisions would, in turn, lead to revision of the IST database limits.

While not reported in PIP 0-O98-0165, the inspectors found that calculation OSC-4281, "LP GL 89-10 MOV DP," Revision 5, conflicted with calculation OSC-2820 but was consistent with the current DBD and IST database, as it indicated there were no design basis stroke time limits for LP-21 and -22. The licensee issued PIP 0-O98-5928 to assure correction of OSC-4281.

PIP 0-O98-0165 did not report that an extent of condition review had been performed to determine whether similar problems existed for other systems. The licensee stated that corrective actions for PIP 0-O98-0707 and LER 50-269/98-04 would assure that IST stroke times and DBD stroke time requirements for other valves and systems were in agreement with calculations like OSC 2820. In addition, the licensee noted that broader corrective actions for configuration management were being undertaken that would assure agreement between calculations. The inspectors reviewed the LER "Planned" corrective action 2 and found that it stated that all emergency operating procedure setpoints would be reviewed for accuracy and completeness and that the inputs would be verified to be current and appropriate.

PIP 0-O98-0179, dated January 13, 1998, identified that the IST program had never required leak testing of LPI valves LP-40, -41, and -42 for Units 1,2, and 3 even though they had historically provided single valve protection for boundaries that should be leak tight by design. The valve configuration in all three units was being modified (already completed for two units) and the PIP identified the need to evaluate leak testing for the valves in the new configurations. The PIP stated that the valves had not been included in the IST program because the DBD did not clearly indicate that the valves had specific leakage criteria. The PIP subsequently recorded that LP-42 had been determined to require leak testing, a revision form had been completed to add the valve to the IST program, and procedures had been developed to leak test LP-42. The inspectors verified that LP-42 was listed in the IST program and that procedures had been developed for leak testing. They reviewed the Unit 3 leak test procedure and noted that the test method leak tested valves LP-40 and LP-41 along with LP-42.

The inspectors noted that no corrective action was identified in PIP 0-O98-0179 addressing the DBD. In response, the licensee added a sentence to the problem evaluation in the PIP which stated that the DBD had been revised to specify that LP-42 "shall be substantially leak tight." The inspectors reviewed the DBD and verified the revision.

The inspectors found no mention in PIP 0-O98-0179 of an extent of condition review to determine if other valves might have been improperly omitted from leak testing in the IST program. When questioned, licensee personnel indicated the omission of inservice leak testing in this instance was considered an isolated condition.

The inspectors noted that the above PIPs did not document corrective actions to prevent recurrence. In response, licensee personnel informed the inspectors of controls that had been initiated to improve the recognition and communication of design changes to the IST program. The inspectors verified these changes, which were as follows:

- NSD 301, "Nuclear Station Modifications," Revision 14, contained a Technical Issues Checklist (TIC) which was to be completed when preparing a minor modification such as a modification that might affect the performance of pumps or valves. A checkoff step had been added which asked if the change affected a valve or pump in the IST program. If the reply was "yes", the TIC stated that appropriate forms should be obtained from the IST manual and the IST Coordinator should be contacted.

- PIP 0-O98-0233, dated January 15, 1998, addressing surveillance problems, specified a corrective action to further define and formalize the process and responsibilities for communicating design changes impacting IST from the engineers to the IST Coordinator for incorporation into the IST program. The corrective action was being informally implemented as instructions and forms provided to engineers via e-mail. PIP 0-O98-5767, dated December 3, 1998, identified January 31, 1999, as the planned date for formal incorporation into the licensee's program.

This unresolved item is closed.

c. Conclusions

The inspectors concluded that the licensee was adequately addressing the IST program and design control process interface problems that had been identified through the licensee's audit. Various licensee corrective actions were not complete and will be examined in future NRC inspection, as noted in Section M3.1 of this IR.

E8.9 (Closed) LER 50-269/97-10-00: Inadequate Analysis of Emergency Core Cooling System (ECCS) Sump Inventory due to Inadequate Design Analysis

This event was discussed in NRC Inspection Reports 50-269,270,287/97-16 and 97-18. Additional follow-up was done this inspection on the corrective actions described in the LER. The inspectors verified that the immediate and subsequent corrective actions were completed. The operability evaluation, completed on November 23, 1997, concluded that the reactor building emergency sump and associated ECCS were operable. All units were considered operable in the past and present. However, the licensee is continuing it's study regarding the available net positive suction head (NPSH) in response to Generic Letter 97-04, Assurance Of Sufficient Net Positive Suction Head For

Emergency Core Cooling And Containment Heat Removal Pumps. The licensee issued LER 50-269/98-11-00, Available NPSH for RBS Pumps Outside Design Basis Due to Incorrect Interpretation. System engineering has determined several options to improve available NPSH. These options are currently under review by NRR through Generic Letter (GL) 97-04. The licensee has submitted, dated 10/2/98, a proposed license amendment regarding the reactor building over pressure to assure sufficient NPSH for the reactor building spray pumps and other ECCS pumps. This action is currently under review.

Another corrective action, described in the LER was to perform a Self Initiated Technical Audit, SITA. This has been completed and 48 PIPs have been documented. The majority of these new PIPs are not directly related to this issue. The PIP process will track these PIPs to completion. Based on the on-going actions related to this issue, This LER is closed.

E8.10 (Closed) VIO 50-269,270,287/97-16-03: Inadequate Procedures

The inspectors verified the corrective actions described in the licensee's response letter, dated February 25, 1998, as completed. Additional time has been allocated into the review process to improve the quality of the review and hence the quality of the procedures. Shutdown procedures and HPI system procedures have been revised as part of the corrective actions for this violation. This violation is closed.

E8.11 (Closed) LER 50-269/97-02 (Revisions 0, 1, and 2): Reactor Building Cooling Units Technically Inoperable Due to Design Deficiency

On February 20, 1997, the LER was submitted as an initial LER, followed by Revision 1 on July 31, 1997, which described potential impact of water hammer in the auxiliary cooling units. On August 13, 1997, Revision 2 was submitted to further describe the water hammer event and to describe corrective actions. This LER and its revisions were issued as a result of reviews requested by Generic Letter 96-06: Assurance of Equipment Operability and Containment Integrity During Design Basis Conditions, issued September 30, 1996.

NRC Inspection Reports 50-269,270,287/96-20, 97-01, 98-01, 98-07, and 98-09 discussed GL 96-06 and these LER revisions. Additional followup was completed this inspection and the long-term corrective actions have been completed or are in process. Final resolution of this issue will be tracked through responses and followup of GL 96-06, water hammer issues. The status and schedule for completion of the various action items are presented in a letter to the NRC from Duke Energy, dated September 22, 1998: Supplemental Response to GL 96-06. Based on the above, LER 50-269/97-02 Revisions 0, 1, and 2 are closed.

E8.12 (Closed) IFI 50-269,270,287/97-02-09: BWST Temperature Requirements

This issue was reported to the NRC on February 13, 1997, and LER 50-269/97-01 was issued. On February 17, 1997, the LER was reviewed and closed in NRC Inspection Report 50-269,270,287/98-09, Section O8.4. No additional information was revealed during followup of the IFI; therefore it is closed.

E8.13 (Open) VIO 50-269,270,287/97-01-03: Failure to Follow Procedure

The inspectors verified the corrective actions described in the licensee's response letter, dated May 21, 1997. The immediate and subsequent actions have been completed. Items 1 and 2 of the planned actions have been completed, but item 3 has not been done. This item involves a one-time test to verify that the wiring configuration is correct at the associated plant components. This test would require all three units to be shut down at the same time. The proper wiring configuration has been verified at each unit separately to match the as built drawings; therefore the licensee is considering deleting the commitment as not beneficial. Pending final resolution, this violation will remain open.

IV. Plant Support Areas

R1 Radiological Protection and Chemistry Controls

R1.1 Tours of the Radiological Control Area (RCA) (71750)

The inspectors periodically toured the RCA during the inspection period. Radiological control practices were observed and discussed with radiological control personnel, including RCA entry and exit, survey postings, locked high radiation areas, and radiological area material conditions. The inspectors concluded that radiation control practices were acceptable.

P4 Staff Knowledge and Performance in Emergency Preparedness (EP)

P4.1 Exercise Scenario

a. Inspection Scope (82302)

The inspectors reviewed the drill scenario to determine if it was of sufficient detail and challenge to provide for a successful demonstration of corrective action for the two exercise weaknesses identified during the August 18, 1998, exercise.

a. Observations and Findings

The drill scenario package was detailed and the scenario contained a sufficient number of events for the emergency response organization to demonstrate the drill objectives and corrective actions for the previously identified exercise weaknesses.

b. Conclusion

The scenario developed for this drill was adequate for demonstrating corrective actions to the exercise weaknesses identified on August 18, 1998.

P8 Miscellaneous Emergency Preparedness Issues (92904)

P8.1 (Closed) Inspector Followup Item 50-269, 270, 287/98-13-01: Exercise Weakness Identified for Failure to Follow up on the Damage Report from Security That Delayed Critical Damage Assessment

(Closed) Inspector Followup Item 50-269, 270, 287/98-13-02: Exercise Weakness Identified for Failure to Provide a Timely Classification of the General Emergency

a. Inspection Scope (82301)

During this inspection, the inspectors focused on the observation and evaluation of the performance of the emergency response organization (ERO) in the Technical Support Center (TSC) and the Emergency Operations Facility (EOF). The assessment of the licensee's performance in these two facilities would allow a determination of effective corrective action for the exercise weaknesses noted below. The inspectors also reviewed the licensee's actions taken since the August 1998 exercise.

b. Observations and Findings

The inspectors reviewed the licensee's "Emergency Drill Recovery Action Plan", which was developed to address the two exercise weaknesses from the August 18 exercise, as well as four licensee-identified areas for improvement. This plan was approved by station management on September 3, 1998. Based upon review of documentation of eight tabletop drills conducted with TSC/ Operations Support Center (OSC)/EOF personnel during October-December 1998, the inspectors concluded that the licensee had undertaken a major effort to effect improvements in its emergency response capability. The focus of the improvement was on those areas found to be deficient during the August exercise.

During the drill, the inspectors observed that the ERO performed all aspects of the response in a well-organized manner. Inspectors attention was particularly focused on the coordination of damage assessment information and the classification of the emergency conditions. In both of these areas, the inspectors observed very effective ERO performance. The inspectors determined that the previously identified exercise weaknesses had been corrected.

c. Conclusion

The licensee demonstrated effective corrective actions for the exercise weaknesses identified during the August 1998 exercise.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

During the period, the inspectors toured the protected area and noted that the perimeter fence was intact and not compromised by erosion or disrepair. Isolation zones were maintained on both sides of the barrier and were free of objects which could shield or conceal an individual. The inspectors periodically observed personnel, packages, and vehicles entering the protected area and verified that necessary searches, visitor escorting, and special purpose detectors were used as applicable prior to entry. Lighting of the perimeter and of the protected area was acceptable and met illumination requirements.

S3 Security and Safeguards Procedures and Documentation

S3.1 Security Program Plans

a. Inspection Scope (81700)

The inspectors evaluated Revisions 7 and 8 of the Duke Power Company Nuclear Security and Contingency Plan (PSP). This was to ensure that the changes were consistent with PSP commitments in Chapter 11 and to determined the adequacy and compliance with 10 CFR Part 50.

b. Observations and Findings

The inspectors reviewed Revision 7, dated April 20, 1998, to the PSP which was effective upon the implementation of the new security computer and access control system. The changes involved the updating of the PSP to incorporate the new computer and access control system, and the implementation commitments of the licensee to this upgrade. Other changes in Revision 7 were for improved clarification and correction of previous errors.

The inspectors also reviewed Revision 8 to the PSP effective October 5, 1998. The changes involved clarification improvements and correction of previous errors.

The inspectors also interviewed security force personnel to determine their familiarity with the changes reviewed. The reviewed changes were consistent with plan commitments and 10 CFR Part 50.

c. Conclusions

The licensee's security plan changes were thorough, well documented, and consistent with the Physical Security Plan commitments and 10 CFR Part 50.

S4 Security and Safeguards Staff Knowledge and Performance

S4.2 Response Capabilities

a. Inspection Scope (81700)

The inspectors evaluated the licensee's response to NRC Information Notice (IN) 98-35, "Threat Assessments and Consideration of Heightened Physical Protection Measures," dated September 4, 1998.

b. Observations and Findings

The licensee was coordinating with the other Duke nuclear sites to revise Security Procedure (SP) 615, "Security Conditions," to meet the guidelines of IN 98-35. This was to ensure a consistent approach to future NRC response communications.

c. Conclusion

The licensee's actions to implement NRC Information Notice 98-35, "Threat Assessments and Consideration of Heightened Physical Protection Measures," dated September 4, 1998, were considered adequate.

S6 Security Organization and Administration

S6.2 Management Effectiveness

a. Inspection Scope (81700)

The inspectors reviewed indicators of management attitude, performance, and effectiveness to determine the adequacy of management support for the licensee's physical security program.

b. Observations and Findings

The inspectors interviewed management and non-management personnel and reviewed security related documents to determine the breadth and depth of the effectiveness of site and security management and program effectiveness resulting from management support. Licensee management exhibited an awareness and favorable attitude toward physical protection requirements. The following item demonstrated a strong management performance in support of the security program:

- The maintenance, repair, replacement, and testing support performances were demonstrated by the major task of installing, implementing, testing, and turnover of the new Duke corporate security computer and access control system. Oconee was the last of the three Duke nuclear sites to be integrated into the system.

The following items demonstrated strong management effectiveness in support for the security program:

- Strong effective support through written policies and procedures were involved in the new Duke security computer and access control system. Site security personnel and management were involved in the development and training necessary for this project.

- Organizational and position responsibilities were clearly defined in the PSP and procedures. Personal ownership and accountability of policies, procedures, and expectations were understood by individuals interviewed.

- The close interface and coordination among the three Duke nuclear site security managers gave opportunity to coordinate, execute, and initiate corporate policies effectively and efficiently.

- Corporate and site management's attitude has been very effective, proactive, and supportive since 1996. This has been demonstrated by the following:

  - Inclusion of security deficiencies and events into the corporate PIP.

  - The owner controlled area traffic gates with bullet resistant access control stations.

  - The excellent support in the evaluation, corrective actions, and disposition of the event items documented in the PIPs, Security Event Logs (SEL), and LERs.

- Creation of the Failure Investigation Process Team with engineering management level involvement in resolving network and power supply problem.

- Acquisition of laser tactical response training equipment for force-on-force drills.

- Corporate sponsored tactical response training by contractors.

- A back-up access computer to process protected area access if the hand geometry units are unavailable.

- External assessment of response capabilities by a contractor.

- Enhanced defensive capabilities by the addition of more delay systems, bullet resistant enclosures, and ballistic steel defensive positions.

- Acquisition of a new security patrol vehicle.

- Security lesson plan consolidation and upgrade coordination among the three Duke nuclear sites.

• The security management's support of security personnel's innovative and progressive approaches enhanced current policies and procedures, and resolved developing issues before the issues become a problem. This was demonstrated in the excellent tracking and trending program administered by the security personnel. The inspectors considered the tracking and trending program as a strength to the security program at Oconee Nuclear Station.

c. Conclusion

Corporate, site and security management were very effective in providing support to the Physical Security Program. This was a major strength in the Duke nuclear security program.

S7 Quality Assurance in Security and Safeguards Activities

S7.2 Problem Analysis

a. Inspection Scope (81700)

The inspectors reviewed and evaluated a sample of problem analyses of logged safeguards events, PIPs, and LERs.

b. Observations and Findings

During the inspection, a representative sample of the problems identified by inspections, LERs, and SELs were reviewed to verify that the problems were appropriately assigned, analyzed, reached logical conclusions and prioritized for corrective action by the licensee. The inspectors found that 688 security PIPs had been opened during the last two calendar years. Forty-five PIPs were still open and only one had been open since 1997. The 1997 PIP item was scheduled to be closed during February 1999. The problem analyses of the SELs in the quarterly treading reports were thorough and

detailed. The licensee analyzed the 12 subclassifications of hardware equipment events, 10 subclassifications of human error events, and any increasing and/or decreasing trends of any of the event categories. Four security individuals were trained in Root Cause Analysis. The inspectors found this area to be a major strength in the security program.

c. Conclusions

The licensee reviewed and analyzed problems, reached logical conclusions, and prioritized the problems for appropriate corrective action. This problem analysis program was a major strength to the security program.

S7.3 Corrective Actions

a. Inspection Scope (81700)

The inspectors reviewed and evaluated a sample of corrective actions implemented by the licensee as documented in the SELs, PIPs, and LERs.

b. Observations and Findings

The inspectors reviewed a sample of corrective actions that had been implemented to verify that the actions taken were technically sound and performed in a timely manner. The effectiveness of the corrective actions was reflected in the long term downward trend of safeguards events. Also, contributing to the success of the corrective actions was the concise, thorough, and timely problem analysis process cited in Section S7.2.

c. Conclusions

The licensee's corrective actions were technically sound, effective, and performed in a timely manner.

S7.4 Effectiveness of Management Controls

a. Inspection Scope (81700)

The inspectors evaluated the overall effectiveness of the licensee's controls for identifying, analyzing, and resolving problems. The inspectors evaluated the adequacy of corrective actions to prevent recurring problems. The inspectors also evaluated whether there were strengths or weaknesses in the controls for issues that could enhance or degrade plant operations or safety.

b. Observations and Findings

The inspectors reviewed previous audits, self-assessment program documents, LER, SEL, and PIP documents to ascertain the licensee's effectiveness of management controls. The licensee's strong problem analysis program was reflected in the aggressive PIP program and documentation. Adverse events, trends, and problems were identified, analyzed, and eventually brought to closure through the PIP program. The absence of recurring major regulatory issues, the long term downward trend of loggable safeguards events, the continued strong support in upgrading the tactical response capabilities, and the positive upgrading of the security computer system supporting the security hardware and systems was indicative of the effectiveness and

involvement of the licensee's management controls. The licensee's continued expansion and refinement of the above discussed management tools and controls were considered to be the driving force of a strong security program.

c. Conclusions

The licensee's management controls of the security program were aggressive, effective, and comprehensive.

S8 Miscellaneous Security and Safeguards Issues (92904)

S8.3 Protection of Safeguards Information

a. Inspection Scope (81810)

The inspectors evaluated the licensee's program to protect Safeguards Information (SGI) against unauthorized disclosure, as required by 10 CFR 73.21.

b. Observations and Findings

The inspectors reviewed LER 50-269/98-S-03-0 and PIP 4-O98-5843. In the LER and PIP the licensee determined that a drawing classified as SGI was found by a security officer unsecured and unattended in a cable room. The security officer took immediate control of the document and notified the Security Shift Supervisor. The document was a drawing of vital area hardware. The licensee initiated a heightened state of awareness for the hardware identified in the compromised drawing. An inventory of the safeguards container, located within the protected area, verified that all other drawings were present in the container. The container's padlock combination was changed to restrict access to the container. A review of the container sign-in/out log indicated that the document had been uncontrolled for approximately 22 hours. This event was reported to the NRC on the Emergency Event Notification System at 4:09 p.m. on December 7, 1998.

The licensee's root cause analysis indicated that the event was "inappropriate action," in that personnel failed to follow established procedures and policies for control of SGI. Corrective actions were as follows:

- Prohibiting two employees involved in the event from being allowed independent and unrestricted access to SGI.
- Developing a single point of contact for issuing and returning SGI documents from the Engineering Safeguards Work Area.
- Continuing the event investigation to ascertain reasons for container sign-in/out log discrepancies found during the preliminary investigation.
- This event was contrary to 10 CFR 73.21(d) that requires that while in use, SGI shall be under the control of an authorized individual, and while unattended, SGI shall be stored in a locked security storage container. In addition, this event is contrary to Duke Power Company's Nuclear Policy Manual, Nuclear System Directive: 206, "Safeguards and Information Control," section 206.7.1 "Control While in Use," that paraphrases the requirements of 10 CFR 73.21(d)(1). The inspectors noted that although several previous violations regarding various aspects of SGI control were identified within the previous two years, associated

corrective actions would not have prevented the issue identified in LER 50-269/98-S-03. This non-repetitive, licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC enforcement policy. This issue is identified as NCV 50-269,270,287/98-11-09: Failure to Control Safeguards Information. The inspectors also closed LER 50-269,270,287/1998-S-03-0 as a results of this review.

c. Conclusion

The inspectors review of LER 50-269/98-S-03-0 and PIP 4-O98-5843 resulted in a NCV for a SGI document being unsecured and unattended.

S8.4 Access Authorization Program

a. Inspection Scope (81700)

The inspectors evaluated LER 50-269/98-S-02-0 to verify that the licensee's corrective actions were according to the Duke Power Company's Access Authorization Program and regulatory requirements.

b. Observations and Findings

On November 25, 1998, the licensee received information from a FBI criminal history check that a contract employee had a prior criminal record that was not disclosed by the individual on his background investigation questionnaire. A contract individual intentionally failed to report criminal offenses on his pre-screening record. The licensee had completed all of the requirements to issue a temporary unescorted access, and subsequently granted protected and vital area unescorted access to the individual on October 23, 1998, in accordance with 10 CFR 73.56. On November 30, 1998, the licensee terminated the employee's unescorted access upon determining the individual's unreliability. This termination data was added to the Personnel Access Data System (PADS). The licensee's root cause analysis of the event revealed that the employee had a willful desire for employment and this desire did not involve any malicious intent with respect to the health and safety of the public. The contractor was with another unescorted access authorized individual when he entered a vital area on one occasion for approximately two minutes. The licensee investigated, documented and implemented corrective actions as described in PIP 4-O98-5678. The responsiveness and corrective actions of the security organization for this falsification of personnel history were timely and appropriate. The event reported in this LER had no safety significance and was closed. The licensee did not violate any regulatory requirements; consequently, the inspectors closed LER 50-269/1998-S-02-0, Failure to Report Criminal Offenses on Pre-Employment Screening Record.

c. Conclusion

The inspectors review of LER 50-269/98-S-02-0 and PIP 4-O98-5678 resulted in the determination that the licensee did not violate any licensee or regulatory requirements; consequently, the inspectors closed LER 50-269/98-S-02-0.

F1 Control of Fire Protection Activities

F1.1 Fire Protection Impairments and Compensatory Actions

a. Inspection Scope (64704)

The inspectors reviewed the UFSAR, Section 16.0, "Selected Licensee Commitments (SLC)," NSD 316, Revision 1, "Fire Protection Impairment and Surveillance," and fire protection calculation, OSC 6832, Rev. 0, "Technical Basis for Roving Continuous Fire Watches." The inspector also observed conditions in the plant involving compensatory actions for degraded fire barrier penetration seals , reviewed fire watch round sheets, and spoke with several fire watches and the station fire protection engineer (FPE) to determine if the fire watch program implementation satisfied the objectives established by the licensee's approved fire protection program.

b. Observations and Findings

The fire protection impairment procedure, NSD 316, applied to all fire protection features within the owner controlled areas required by the SLC. The procedure established hourly fire watch patrols for fire barrier impairments when the fire detection instrumentation in the affected area was operable. If the fire detection instrumentation in the affected area was inoperable, a continuous fire watch was required.

During a tour of the facility on December 10, 1998, the inspectors observed two fire watches and discussed fire watch responsibilities and tour duration times with the two fire watches, the FPE, and a work supervisor. The fire watches were designated as roving continuous fire watches performing surveillance of the first and fifth floors of turbine building, 3-hour rated fire barrier walls adjacent to the auxiliary building. Penetration seals in these fire barrier walls had been taken out-of service for repairs. The inspectors noted that the fire watches were also performing hourly patrols of several areas of the auxiliary building concurrently with their roving continuous fire watch patrols in the turbine building.

The inspectors accompanied the fifth floor turbine building fire watch during a patrol of the turbine building floor and an equipment room in the auxiliary building. The inspectors noted the fire watch left the turbine building area unattended during the patrol of the auxiliary building equipment room for a duration of about 5 minutes.

A first floor turbine building fire watch was observed reentering the turbine building area from a tour of the auxiliary building. This fire watch indicated to the inspectors that the auxiliary building hourly fire watch tour consisted of a patrol of six separate plant areas and it took about 20 minutes to complete the hourly fire watch patrol route. Subsequent timing by the licensee of another fire watch patrol indicated that the affected turbine building areas was left unattended for about 16 minutes. This left the turbine building continuous fire watch area unattended for longer than 15 minutes. This was identified and reported to the site FPE and maintenance management.

The inspectors determined that the fire watch routes set up to perform the hourly fire watch patrols had serious time constraints; such as, requiring the fire watch personnel to cross through radiation control area boundaries and not being able to quickly exit due the potential of contamination or radiation monitoring equipment problems. The inspectors also determined that the fire watch personnel did not have a full understanding of the procedural time constraint of not leaving a continuous fire watch area unattended for

more than 15 minutes. The licensee immediately changed the fire watch routes to eliminate the time constraints, counseled the fire watch personnel on the time requirements for continuous fire watches, and initiated Problem Investigation Process (PIP) Report 0-O98-5897 and PIP 0-O98-5899 to address the inspectors' concerns identified to the licensee management in this area.

Technical Specification 6.4.1.l. requires the station be maintained in accordance with approved procedures and that written procedures with appropriate checkoff lists and instructions be provided for fire protection program implementation. Nuclear Station Directive 316, Section 316.5.5, "Personnel and Supervision Responsible for Performing a Fire Watch," states that a continuous fire watch requires surveillance of the affected area at least once per 15 minutes during the entire time of the impairment. The inspectors concluded that the turbine building continuous fire watch was not being performed in accordance with NSD 316 requirements in that the affected turbine building area had been left unattended for longer than 15 minutes to accomplish hourly fire watch tasks. The failure to follow fire protection program procedures for maintaining a continuous fire watch is identified as VIO 50-269,270,287/98-11-10, Failure to Properly Implement Procedural Requirements for a Continuous Fire Watch.

c. Conclusions

A violation of procedural requirements was identified for not properly implementing continuous fire watch requirements. An observed fire watch left the affected turbine building continuous fire watch area unattended for longer than 15 minutes.

F8 Miscellaneous Fire Protection Issues (92904)

F8.1 (Closed) Inspection Followup Item (IFI) 50-269,270,287/97-15-07: Revalidation of Fire Barrier Seals

The issue related to the lack of available documentation to verify that fire barrier penetration seals were installed in accordance with design specifications bounded by configurations that had satisfactorily passed 3-hour fire resistance testing.

The inspectors reviewed the Duke Energy Corporation letter to the NRC dated August 4, 1998, "Fire Barrier Penetration Seals," that described the licensee's three-site plan and schedule to update penetration seal design-basis documentation and configuration information. This plan included the performance of inspections to document as-built penetration seals configurations and the development of design-basis documents to describe bounding tested configurations and engineering analysis.

The inspectors also reviewed the scope and completion status of the penetration seal plan implementation. The inspectors verified that the plan implementation was on schedule and the licensee's penetration seal design and installation parameters (being verified during licensee walk downs) satisfied the guidance described in Sections 3.1 and 3.2 of Generic Letter (GL) 86-10. The inspector concluded that the scope of the fire barrier penetration seal plan for Oconee was sufficiently documented in the licensee's PIP corrective action program to assure that the corrective actions identified in IFI 50-269,270,287/97-15-07 would be completed.

F8.2 (Closed) VIO 50-269,270,287/97-15-08: Fire Fighting Strategies Not Provided for All Safety-Related Areas

This issue involved the lack of fire fighting strategies for all safety-related plant areas. The inspectors reviewed the corrective actions identified by the licensee in a letter dated January 15, 1998, and verified that the actions were reasonable and complete. The inspectors also reviewed operator continuous training session records for the second and third quarters of 1998, and verified that all qualified members of the fire brigade had been trained on the current 130 updated fire fighting strategies. The inspectors concluded that the updated fire fighting strategies identified all plant safety-related areas where a potential fire would be possible.

F8.3 (Closed) VIO 50-269,270,287/98-06-11: Failure to Follow Procedures for Control of Combustible Materials

This issue concerned instances in which plant personnel failed to follow fire protection program combustible materials and housekeeping control procedures. The inspectors reviewed the corrective actions identified by the licensee in their response to the violation dated August 12, 1998, and verified that the actions were acceptable, satisfactorily completed, or in progress and scheduled in the licensee's corrective action tracking program to assure that the corrective actions would be completed. During plant tours conducted this inspection period, no issues involving uncontrolled combustible materials or housekeeping were identified. The licensee has improved plant combustible materials control and housekeeping.

F8.4 (Closed) Unresolved Item (URI) 50-269,270,287/98-06-12: Determine if the Installation, Maintenance, Repair, and Inspection of Fire Barrier Penetration Seals Are in Conformance With Vendor Requirements

On May 13-18, 1998, during a Triennial Fire Protection Audit the licensee determined that penetration seals in the Auxiliary Building fire barrier walls of each unit that separated the East and West Penetrations Rooms were not installed correctly to achieve a full three-hour fire rating. These fire barrier walls separate the Standby Shutdown Facility (SSF) shutdown components and normal plant safe shutdown components. The fire barrier penetration seals were found to have inadequate depth of silicone foam and gaps in the silicone foam that extended through the barrier walls. The fire barriers were declared inoperable and fire watches were established for the affected fire zones in accordance with the fire protection program requirements.

The inspectors verified that plant personnel documented these problems in PIP 0-098-2620, which included a past-operability determination engineering calculation, evaluations of the causes of the silicone foam penetration seal problems and corrective actions to repair the penetration seals. The inspectors reviewed the PIP, fire boundary drawings, calculation OSC 7185, "Fire Evaluation of the East West Penetration Room Wall," procedural guidance for fire penetration seal repairs, and observed recently repaired silicone foam penetration seals. The inspectors found that the fire resistence capability of the as-found degraded fire barriers had been throughly evaluated. This evaluation concluded that due to low fire potential, early fire detection by automatic fire detectors (supplemented by fire watch patrols) and rapid fire brigade response, a potential fire in the affected areas would be detected and contained such that safe shutdown capability would not be adversely affected. The inspectors also found that the penetration seals had been properly repaired to their required three-hour rated design configuration.

Paragraph 3.E of the Oconee Operating License states that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report and as approved in the Safety Evaluation Reports (i.e., NRC's Fire Protection Safety Evaluation Reports). Oconee Safety Evaluation Report dated April 28, 1983, Section 4.7.6., states that the walls separating the East and West penetration rooms are separated at each unit by three-hour rated fire barriers.

The inspectors verified that the licensee's Triennial Fire Protection Audit, SA-98-100(ALL)(RA), identified that a number of penetration seals in the fire barrier walls separating the East and West penetration rooms at each unit were not installed as required and were not three-hour fire rated as evidenced by inadequate depth of silicone foam and gaps in the silicone foam that extended through the barrier wall. This failure had affected the fire barriers since their last work performed on the seals for all three units in 1988.

Licensee management has appropriately addressed the factors that caused the above non-compliance in the corrective actions described in PIP 0-098-2620. The failure to implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety Analysis Report and as approved in the April 28, 1983, Safety Evaluation Report (the walls separating the East and West penetration rooms are separated at each unit by three-hour rated fire barriers) is considered to be a violation. This non-repetitive, licensee-identified and corrected violation is being treated as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy, and is identified as NCV 50-269,270,287/98-11-11: Failure to Maintain Required Penetration Seal Fire Barrier Rating.

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 January, 20, 1999. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

Partial List of Persons Contacted

Licensee

L. Azzarello, Design Basis Engineering Manager
E. Burchfield, Regulatory Compliance Manager
T. Coutu, Superintendent of Operations
T. Curtis, Mechanical System/Equipment Engineering Manager
G. Davenport, Operations Support Manager
B. Dobson, Engineering Work Control Manager
J. Forbes, Station Manager
W. Foster, Safety Assurance Manager
T. Hartis, Recovery Plan Coordinator
D. Hubbard, Modifications Manager
C. Little, Civil, Electrical & Nuclear Systems Engineering Manager
W. McCollum, Site Vice President, Oconee Nuclear Station
B. Medlin, Superintendent of Maintenance
M. Nazar, Manager of Engineering
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
IP37550	Engineering
IP40500	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP61726	Surveillance Observations
IP62707	Maintenance Observations
IP64704	Fire Protection Program
IP71707	Plant Operations
IP71714	Cold Weather Preparations
IP71750	Plant Support Activities
IP73756	Inservice Testing
IP81700	Physical Security Program for Power Reactors
IP81810	Protection of Safeguards Information
IP82301	Evaluation of Exercises for Power Reactors
IP82302	Review of Exercise Objectives and Scenarios for Power Reactors
IP92700	Onsite Followup of Written Event Reports
IP92902	Followup - Maintenance
IP92903	Followup - Engineering
IP92904	Followup - Plant Support
IP93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-269,270,287/98-11-01	IFI	Keowee Commercial Operation to Emergency Start Power Evaluation (Section O1.5)
50-270/98-11-02	IFI	Retraction of Unit 2 Engineering Safeguards Actuation Event (Section O1.5)
50-269,270,287/98-11-03	URI	Overtime Procedures and Controls (Section O7.2)
50-287/98-11-04	NCV	Personnel Error at Keowee Results in Overheating the Closing Coils for the Unit 1 Field Breakers (Section O8.2)
50-269,270,287/98-11-05	EEI	Stroke Time Each MOV to Its Safety Position(s) (Section M3.1)
50-269,270,287/98-11-06	NCV	Failure to Follow Procedure (Section M8.1)
50-269,270,287/98-11-07	EEI	Three Examples of Failure to Meet the Requirements of 10 CFR 50 Appendix B, Criterion XVI (Sections E2.4 and E8.2)
50-269,270,287/98-11-08	NCV	An Individual was Incorrectly Placed on the Qualified Reviewer's List Without Completing all Required Training (Section E8.6)
50-269,270,287/98-11-09	NCV	Failure to Control Safeguards Information (Section S8.3)
50-269,270,287/98-11-10	VIO	Failure to Properly Implement Procedural Requirements for a Continuous Fire Watch (Section F1)
50-269,270,287/98-11-11	NCV	Failure to Maintain Required Penetration Seal Fire Barrier Rating (Section F8.3)
50-269/98-16	LER	Three Interpretations did not Meet Technical Specifications Due to Inadequate Management Policy, dated December 21, 1998 (Section O1.5)
50-269/98-S-02	LER	Security Access Revoked for Falsification of Criminal Record, dated December 17, 1998 (Section O1.5)
50-269/98-17	LER	Inadequate Work Planning Results in Missed Surveillance, dated December 17, 1998 (Section O1.5)

50-269/98-S03	LER	Failure to Follow Procedures Results in Uncontrolled Safeguards Information Drawing, dated December 31, 1998 (Section O1.5)
50-269/98-18	LER	Potential Loss of Emergency Siphon Vacuum System due to Failure Analysis Oversight, dated January 9, 1999 (Section O1.5)
50-270/96-03-01	LER	Technical Specification Required Shutdown Due to Inadequate Work Planning, dated January 21, 1999 (Section O1.5)
50-287/98-01	LER	Missed Surveillance Due to Inappropriate Actions, dated December 31, 1998 (Section O1.5)
50-287/98-02	LER	Reactor Coolant System Pressure Limit for Containment Integrity Exceeded Due to Inappropriate Action, dated January 14, 1999 (Section O1.5)
50-287/98-03	LER	Missed Calibration Due to Lack of Training and Lack of Formal Process, date due January 27, 1999 (Section O1.5)
50-287/98-04	LER	Broken Wire Causes Reactor Trip During Control Rod Drive Breaker Test, date due February 1, 1999 (Section O1.5)

Closed

50-269,270,287/98-10-02	URI	Inappropriate Action Results in Unexpected ESF Component Actuation (Section O8.1)
50-269/98-15	LER	Loss of Onsite Emergency Power Due to Planned Testing, Inappropriate Action, and Inadequate Evaluation of the Impact of Testing on the Components (Section O8.2)
50-269,270,287/97-12-04	IFI	Maintenance Oversight (Section M8.1)
50-269,270,287/95-26-01	IFI	Region II Review of NRC Headquarters Special Report (Section E8.1)
50-269,270,287/97-14-04	VIO	Failure to Implement Vendor Recommendations for DB-25 Circuit Breakers (Section E8.2)
50-269,270.287/97-18-06	IFI	K-Line Breaker Issues (Section E8.3)

50-269/98-10	LER	PRVS Test Method Does Not Meet TS Requirement Due to Inadequate Wording of Licensing Submittal (Section E8.4)
50-269,270,287/98-03-02	VIO	Failure to Perform PRVS Surveillance in Accordance with TS (Section E8.4)
NOED 98-6-011	NOED	Notice of Enforcement Discretion of DPC Oconee Units 1,2, and 3, Regarding TS 4.5.4.1.b.1 (Section E8.4)
50-269,270,287/98-05-01	VIO	Inadequate Corrective Actions for Recurring Problems With Engineering Instructions for Minor and Temporary Modifications (Section E8.7)
50-269,270,287/98-07-04	URI	IST Program and Design Control Process Interface (Section E8.8)
50-269/97-10-00	LER	Inadequate Analysis of ECCS Sump Inventory due to Inadequate Design Analysis (Section E8.9)
50-269,270,287/97-16-03	VIO	Inadequate Procedures (Section E8.10)
50-269/97-02 (Rev. 0 - 2)	LER	Reactor Building Cooling Units Technically Inoperable Due to Design Deficiency (Section E8.11)
50-269,270,287/97-02-09	IFI	BWST Temperature Requirements (Section E8.12)
50-269,270,287/98-13-01	IFI	Exercise Weakness Identified for Failure to Follow up on the Damage Report from Security That Delayed Critical Damage Assessment (Section P8.1)
50-269,270,287/98-13-02	IFI	Exercise Weakness Identified for Failure to Provide a Timely Classification of the General Emergency (Section P8.1)
50-269/98-S-02-0	LER	Failure to report criminal offenses on pre-employment screening records. (Section S8.3)
50-269/98-S-03-0	LER	Failure to control Safeguards Information. (Section S8.4)
50-269,270,287/97-15-07	IFI	Revalidation of Fire Barrier Seals. (Section F8.1)
50-269,270,287/97-15-08	VIO	Fire Fighting Strategies Not Provided for All Safety-Related Areas (Section F8.2)
50-269,270,287/98-06-11	VIO	Failure to Follow Procedures for Control of Combustible Materials (Section F8.3)

50-269,270,287/98-06-12	URI	Determine if the Installation, Maintenance, Repair, and Installation of Fire Barrier Penetration Seals are in Conformance with Vendor Requirements (Section F8.4)
50-287/98-10-07	IFI	Followup on Valve 3LP-17 Erratic Current Trace (Section E2.7)
Discussed		
50-26,270,287/97-16-01	VIO	Failure to Implement Nuclear Systems Directive 408 (Section O8.1)
50-269/98-06	LER	Inadequate Safety Evaluation Results In Operating Outside the Design Basis of the Plant (Section E8.5)
EA 98-199-01014	VIO	USQ Involving Single Failure Vulnerability Introduced by a 1984 Control Room Ventilation System Modification (Section E8.6)
50-269,270,287/97-01-03	VIO	Failure to Follow Procedure (Section E8.13)

List of Acronyms

ABB	Asea-Brown Boveri
AC	Alternating Current
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BWST	Borated Water Storage Tank
CA	Corrective Action
CARB	Corrective Action Review Board
CIT	Continuous Improvement Team
CET	Core Exit Thermocouple
CFR	Code of Federal Regulations
CCW	Condenser Circulating Water
CIT	Continuous Improvement
CRD	Control Rod Drive
CRVS	Control Room Ventilation System
CW	Cold Weather [preparation]
DBD	Design Basis Document
DP	Different Pressure
ECCS	Emergency Core Cooling System
ECCW	Emergency Condenser Circulating Water
EFW	Emergency Feedwater
EOF	Emergency Operations Facility
ERO	Emergency Response Organization
ES	Engineered Safeguards
ESF	Engineered Safety Feature
ESV	Emergency Siphon Vacuum
F	Fahrenheit
FIP	Failure Investigation Process
FPE	Fire Protection Engineer

GL	Generic Letter
HPI	High Pressure Injection
HPSW	High Pressure Service Water
I&E	Instrument and Electrical Department
IFI	Inspector Followup Item
IN	Information Notice
INOT	Independent Nuclear Oversight Team
IP	Inspection Procedure
IPRS	In-Plant Review
IR	Inspection Report
IST	Inservice Testing
ITS	Improved Technical Specifications
KEPES	Keowee Emergency Power and Engineered Safeguards
KHU	Keowee Hydro Electric
KV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LPSW	Low Pressure Service Water
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LSE	Less Significant Event
MATCON	Material Condition
MCC	Motor Control Center
MOV	Motor Operated Valves
MSE	More Significant Event
NPSH	Net Positive Suction Head
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSD	Nuclear Station Directive
NSM	Nuclear Station Modification
OAC	Operator Aid Computer
ONS	Oconee Nuclear Station
OSC	Operations Support Center
OTSG	Once Through Steam Generator
PDR	Public Document Room
PIP	Problem Investigation Process
PM	Preventive Maintenance
PORC	Plant Operating Review Committee
PSIG	Pounds Per Square Inch Gauge
PSP	Security and Contingency Plan
PT	Performance Test
QA	Quality Assurance
QC	Quality Control
RB	Reactor Building
RCA	Radiological Control Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RPS	Reactor Protection System
SEL	Security Event Log
SGI	Safeguards Information
SITA	Self-Initiated Technical Audit

SLC	Selected Licensee Commitments
SP	Security Procedure
SRG	Safety Review Group
SSF	Standby Shutdown Facility
SSW	Siphon Seal Water
TIC	Technical Issues Checklist
TS	Technical Specification
TSC	Technical Support Center
TSI	Technical Specification Interpretation
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VAC	Volts Alternating Current
VDC	Volts Direct Current
VIO	Violation
WO	Work Order