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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:	October 18 - November 28, 1998
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ENCLOSURE 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/98-10,
50-270/98-10, and 50-287/98-10

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

Operations

- After a Unit 1 standby bus breaker relay failure, the operators and shift operations manager exercised sound judgement; were very cognizant of plant conditions; were aware of applicable Technical Specifications and procedures; and controlled and coordinated the followup activities in an excellent manner. (Section O1.1; [POS: 1A - Excellent])

- Following a Unit 2 reactor trip, the overall startup activities by the operators were good. Operators exhibited clear communications, used appropriate procedures, and were attentive to changing plant conditions. The command and control by shift supervision were good. (Section O1.1; [POS: 1A - Good])

- Preparations and training for significant Keowee hydro-electric plant testing were good. (Section O1.1; [POS: 3A, 3B - Good])

- Failure to follow procedure during preparation for Unit 3 drain activities resulted in the loss of approximately 400 gallons from the reactor coolant system and was identified as a non-cited violation **(Recovery Plan Item P1)**. (Section O1.2; [VIO: 1A, 3A - Poor])

- Unit 3 reduced inventory operations were completed properly with appropriate operator action, supervisory oversight, and procedure adherence. (Section O1.2; [POS: 1A, 3A, 3C - Adequate])

- On November 3, 1998, an incorrect repair of a electrical penetration fire sealant resulted in a direct current ground that caused inadvertent main feedwater pump and main turbine trips, with an ensuing Unit 2 reactor trip. Inspector followup of this issue will be performed in the closeout of the associated licensee event report. (Section O1.3; [NEG: 1B, 2B, 3B - Poor])

- The plant equipment responded as expected to the November 3, 1998, Unit 2 reactor trip. (Section O1.3; [POS: 2A - Adequate])

- The operator responses to the November 3, 1998, Unit 2 main turbine and main feedwater pump trips followed by a reactor trip event were excellent. The operators were business like and methodical in their command and control during the recovery. (Section O1.3; [POS: 1B, 3A, 3B - Excellent])

- The corrective action activities in troubleshooting, replacing the damaged cable associated with the November 3, 1998, Unit 2 reactor trip, and the post-repair testing were excellent. (Section O1.3; [POS: 3A, 5B, 5C - Excellent])

- Simultaneous testing of an engineered safeguards channel and a Keowee hydro unit resulted in an unexpected actuation of an engineered safeguards component. This was left unresolved pending further review of licensee corrective actions for a previous similar event **(Recovery Plan Item P1)**. (Section O2.3; [URI: 1A, 3A - Poor])

- Licensee inspection of the Unit 3 low pressure injection pumps revealed several rotating element problems. Those were properly repaired and documented. The licensee plans to examine the other units' pumps as soon as practical. (Section O2.4; [POS: 5A, 5B - Adequate; NEG: 2A - Poor])

- The Top Equipment Problem Resolution process has been fully implemented at Oconee and meets the Recovery Plan goals by functioning to bring about improvements in equipment reliability and operator work-arounds **(Recovery Plan Item SE3 - closed).** (Section O2.5, [POS: 2A, 2B, 5C - Good])

- Through a review of records, the licensee discovered that Unit 1 exceeded a 72-hour limiting condition for operation for low pressure service water flow instrumentation to the low pressure injection decay heat coolers. Additional inspector followup will be performed during review of the associated licensee event report. (Section O2.6; [NEG: 1A, 3B, 4A - Poor])

- The failure to adequately label fuse blocks in the standby bus breakers and a lack of a questioning attitude on the part of the work control senior reactor operator resulted in inoperability of the standby busses and was identified as a non-cited violation. (Section O3.1; [NCV: 1A, 3A - Poor])

- The good questioning attitude by a non-licensed operator regarding fuse labeling was seen as a positive. The corrective actions taken to label the fuses was also seen as a positive. (Section O3.1; [POS: 3B, 5C - Good])

- Fuel movement activities on Unit 3 were conducted in a professional manner with adequate procedures and good adherence to procedures. (Section O4.1; [POS: 1A, 3A, 3C - Good])

- The licensee's implementation of temporary defenses from the Oconee Recovery Plan for management observations during non-outage times was detailed, met the objectives outlined in the Recovery Plan, and were appropriately entered into the corrective action program **(Recovery Plan Item TD1 - closed).** (Section O4.2; [POS: 3C, 5C - Good])

- An inadequate procedure resulted in the isolation of both trains of the Unit 2 Essential Siphon Vacuum System and was considered a non-cited violation. (Section O8.1; [NCV: 3C - Poor; POS: 5A - Adequate])

- The past operability evaluation performed on the reactor coolant makeup pump regarding the use of calculated reactor coolant pump seal return flow instead of actual flow showed proper analysis and resolution of the problem. (Section O8.2; [POS: 5B, 5C - Adequate])

- Regarding a thermal insulation violation closeout, the licensee's corrective actions and closure materials were complete and adequate. (Section O8.3; [POS: 5B, 5C - Adequate])

Maintenance

- The repair activities, established contingencies, the use of thermography, and supervisory oversight for a rectifier cooling water leak repair on the Unit 2 generator was excellent. (Section M1.1; [POS: 3A, 3C - Excellent])

- The performance of the emergency power switching logic tests was good and the Keowee units did not mechanically overspeed trip when electrically tripped from 68 megawatts each. (Section M1.1; [POS: 2A, 3A - Good])

- Overall, maintenance on the Unit 3 core flood check valves was good as evidenced by procedure availability at the work site and the proper control of replacement parts. The use of vendor personnel to perform maintenance increased the experience level of the work force. (Section M1.2; [POS: 3A, 3B - Good])

- The procedure for assembly and disassembly of the Unit 3 core flood check valves contained some weaknesses in the instructions for removing and installing the bonnet and for installing the disc **(Recovery Plan Item NRC7)**. (Section M1.2; [WEAK: 2B - Poor])

- The synchronization checking relays were in poor condition and contributed to a standby bus breaker failure. (Section M1.3; [NEG: 2A - Poor])

- The followup action plan and the initiation of a minor modification to address the failed synchronization relay, which caused a failure of a breaker in the standby bus, were appropriate to address this degraded material condition. (Section M1.3; [POS: 4B, 4C - Good])

- The results of the scheduled and augmented inservice inspection activities reviewed provided clear status of the components acceptability for continued service. This completes the NRC review of the Oconee Inservice Inspection Defense Plan **(Recovery Plan Item SE-8 - closed)**. (Section M1.4; [POS: 2B, 3A - Adequate])

- The licensee's eddy current examination activities were conducted in a conservative manner, with several levels of review during data analysis. (Section M1.5; [POS: 2B, 3A - Good])

- Corrective measures implemented as a part of the Oconee Recovery Plan Work Management Backlog issue were effectively implemented (**Recovery Plan Item OF5 - closed**). (Section M8.1; [POS: 2B - Good])

- Corrective measures implemented as a part of the Oconee Recovery Plan Outage Readiness issue were effectively implemented **(Recovery Plan Item OF6 - closed).** (Section M8.2; [POS: 2B - Good])

- A violation was identified for inadequate corrective action concerning removal of lagging adhesive from stainless steel piping and components. (Section M8.3; [VIO: 4B, 5B, 5C - Poor])

Engineering

- A violation was identified for failure to provide separation between redundant trains of safety-related cables inside two terminal boxes and a main control room panel during installation of Unit 3 Modification ON 32885/0. (Section E1.1; [NEG: 4A, 4B, 4C - Poor])

- The operability analysis and inspections of the Unit 3 reactor coolant pumps were adequate. (Section E2.1; [POS: 4B - Adequate])

- The modification for the reactor coolant pump switchgear was excellent, in that it was technically sound, easily understandable, and was installed in an excellent manner. (Section E2.2; [POS: 4B, 4C - Excellent])

- The modifications and replacements for the Keowee breakers are in progress or have been scheduled. The design, support, procedures, and processes used were good **(Recovery Plan Item NRC6 - closed).** (Section E2.2; [POS: 4A, 4B, 4C - Good])

- The performance of a test following modification of the 7 kilovolt power system was excellent in that personnel used effective communications, stopped the test for unexpected conditions, identified procedure problems, and were continually aware of equipment status at all times. (Section E2.3; [POS: 3A - Excellent])

- Test procedures were poorly written for a post-modification test of the 7 kilovolt and the emergency power switching logic systems **(Recovery Plan Item NRC7).** (Section E2.3; [NEG: 2B - Poor])

- During post-modification testing of the minor temporary modification for the Keowee emergency test, a wrong switch was manipulated which resulted in both Keowee units being inoperable. The inspectors will evaluate potential enforcement with the licensee event report. (Section E2.4; [NEG: 3A, 3B - Poor])

- The Keowee emergency start test procedure was well written, technically correct, and the overall activities involved with the test performance were excellent. (Section E2.4; [POS: 3A, 3C - Excellent])

- A weakness in the design of the temporary modification for the Keowee Unit 2 emergency power test resulted in a test failure. An unrelated equipment failure on Keowee Unit 1 made both Keowee units technically inoperable. (Section E2.4; [WEAK: 2A, 4A, 4C - Poor])

- During the Keowee test, motor operated valve 3LP-17 did not operate as expected. The licensee repaired the valve after the recent problem identification and is investigating. (Section E2.4; [NEG: 2A, 4B - Poor])

- Implementation of the first phase of the high pressure injection system review initiative was consistent with the scope and schedule described in the Oconee Recovery Plan. The corrective actions developed to address the three recommendations from the high pressure injection system reliability study were adequate. This item is closed **(Recovery Plan Item DB1 - closed)**. (Section E2.5; [POS: 4A, 4B, 5C - Adequate])

- The licensee's coatings repairs were adequate with the exception of some minor discrepancies. An apparent violation was identified for failure of the licensee's quality control inspectors to perform and document inspections of the coatings in accordance with quality control inspection procedures. This apparent violation will remain open for a reasonable time to allow the licensee to develop corrective actions **(Recovery Plan Item NRC5)**. (Section E2.6; [EEI: 2B - Poor])

- The decision to delay performance of an operability evaluation of a potentially inadequate cable tray support based on the existence of redundant equipment was identified as a weakness in the justification for delaying the evaluation of the associated Problem Identification Process report. (Section E2.7; [WEAK: 4B, 5B - Poor])

- Identification and evaluation of the deformation/excessive movement of the main steam supply piping to the Unit 2B feedwater pump was a good example of proactive involvement of engineering support of facilities and equipment. (Section E2.8; [POS: 4B, 5A, 5B - Good])

- The root cause analyses and corrective actions for undersized welds or welds which were not inspected by quality assurance were thorough and comprehensive. (Section E8.1; [POS: 5B, 5C - Good])

- The resolution for overstress on the pressurizer surge line drain line nozzle was good. (Section E8.2; [POS: 5B, 5C - Good])

- The corrective actions were considered adequate for an earlier failure to conduct post-modification testing on Keowee over voltage relay. (Section E8.3; [POS: 5C - Adequate])

- Implementation of the Unit 3 emergency condenser circulating water (ECCW) initiative was consistent with the scope and schedule described in the Oconee Recovery Plan. Test procedures were generally well written and required only a few changes. The pre-job briefing was thorough. Test deficiencies and discrepancies were documented for evaluation and resolution. The test acceptance criteria were met or retesting was performed to resolve deficiencies where the test acceptance criteria were not met initially **(Recovery Plan Item DB4 - closed)**. (Section E8.4; [POS: 3A, 4B - Good]

- The inspectors concluded that the safety-related 4 kilovolt switchgear located in the turbine building was not required to be qualified in accordance with the environmental qualification rule based on the licensee's mitigation strategies for high energy line break events that had been previously reviewed and accepted by NRC. (Section E8.5; [POS: 4A - Good])

Plant Support

- Material was labeled appropriately, and areas were properly posted. (Section R1.1; [STREN: 1C - Excellent])

- Personnel dosimetry devices were appropriately worn. (Section R1.1; [STREN: 3A, 3B - Excellent])

- Radiation work activities were planned, radiation worker doses were being maintained well below regulatory limits and the licensee was continuing to maintain exposures as low as reasonably achievable. (Section R1.1; [STREN: 1C - Excellent])

- Poor radiation worker practices at radiological control area control points were observed. (Section R1.1; [NEG: 1C, 3B - Poor])

- Corrective actions for previous issues had not been fully effective. (Section R1.1; [NEG: 5C - Poor])

- The Unit 3 containment prejob briefing was not effective in communicating information to some workers. (Section R1.1; [NEG: 3B - Poor])

- The interactive video computer program for job planning was observed to be a strength towards obtaining exposures as low as reasonably achievable. (Section R1.1; [STREN: 3B - Excellent])

Report Details

Summary of Plant Status

Unit 1 continued to operate at 100 percent power during the reporting period.

Unit 2 began the period at 100 percent power. On November 3, 1998, a grounded and shorted electrical cable in the integrated control system caused a trip of the main generator and both feed water pumps, which resulted in a reactor trip. On November 6, 1998, the unit was returned to 100 percent power, where it remained for the rest of the period.

Unit 3 began and ended the period in a scheduled refueling outage. Major work included replacement of the 3B1 reactor coolant pump, low pressure service water modifications, the addition of an automatic interlock between letdown storage tank level and the high pressure injection suction valves from the emergency borated water tank, and testing of the Keowee hydro units for loading under engineered safeguards conditions.

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.

The inspectors observed the activities of the operators and the shift operations manager involved with a failed relay for the Unit 1 standby bus breaker (Section M1.3). The personnel exercised sound judgement, were very cognizant of plant conditions, were aware of applicable Technical Specifications (TS) and procedures, and controlled and coordinated the followup activities in an excellent manner.

The inspectors observed startup activities for Unit 2 following a reactor trip, on November 5, 1998 (Section O1.3). Overall startup activities were good. Operators exhibited clear communications, used appropriate procedures, and were attentive to changing plant conditions. The command and control by shift supervision was also good.

Significant testing of a Keowee hydro-electric system temporary modification occurred this period. The preparations and training were good. As discussed in Section E2.4, an operator error and poor temporary modification development impacted the testing process. Once testing was satisfactorily completed, the test data was taken under review by the licensee for potential future modifications.

O1.2 Human Performance During Unit 3 Drain for Nozzle Dam Removal (Recovery Plan Item P1)

a. Inspection Scope (71707)

On November 14, 1998, the licensee drained the Unit 3 reactor coolant system (RCS) to reduced inventory conditions in order to remove nozzle dams after maintenance work on the once through steam generators (OTSG). The inspectors observed the reduced inventory activities.

b. Observations and Findings

On November 14, 1998, prior to actual draining of the Unit 3 RCS, operators entered the reactor building (RB) to open the drains from the RCS cold legs to the component drain pump. In the process of aligning these drains operators also inappropriately opened the OTSG drains. This created a bypass path around the nozzle dams and water flowed from the RCS into the OTSG, out the OTSG lower manway, and onto the RB basement floor. The control room operator noticed a drop in level on 3LT-5 and notified operators in the RB to reposition the drain valves. This action stopped the inventory loss. During the 12 minutes in which the nozzle dams were bypassed, approximately 400 gallons of water were lost and RCS level decreased approximately 5 inches. The licensee suspended drain preparation and initiated a root cause evaluation under Problem Investigation Process report (PIP) 3-O98-5473. Due to the RCS piping configuration, water would have remained over the core had the drain path remained undetected.

The operators were performing procedure OP/3/A/1103/011, Draining and Nitrogen Purging RCS, Revision 36, when the loss of inventory occurred. This included Enclosure 4.5, Draining Reactor Vessel (RV) and Cold Legs; Enclosure 4.6, Draining RCS With Component Drain Pump; and Enclosure 4.8, Requirements for Draining to Mid-Loop Operations. The licensee's investigation revealed that the control room operator misread a conditional step in Enclosure 4.6 and directed operators in the RB to open the OTSG drains when those drains should have remained closed. The investigation also revealed that operators had begun the actual procedure steps in Enclosure 4.5 before completing the initial conditions, including a prejob briefing and senior reactor operator (SRO) review of the procedure. The licensee counseled the involved individuals, had lessons learned meetings with each operating shift, and initiated actions to require a peer check for performance of conditional steps. The licensee also initiated corrective actions to enhance procedure OP/1,2,3/A/1103/011 to address the issues of this event and to add an operator aid showing the drain configuration and location of the nozzle dams. Operations personnel also planned to review issues of this event with regard to the shutdown protection plan and command and control.

Nuclear Station Directive (NSD) 704, Technical Procedure Use and Adherence, Revision 7, stated that continuous use procedures shall be performed using step-by-step adherence unless flexibility is allowed by the procedure or NSD 704. Neither procedure OP/3/A/1103/011 nor NSD 704 allowed such flexibility. The inspectors determined that the actions taken by the operators were not in compliance with licensee procedures and constituted a violation of 10 CFR 50 Appendix B, Criterion V. 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 50-287/98-10-01: Failure to Follow Procedure Results in Reactor Coolant System Inventory Loss.

The licensee later proceeded with reduced inventory operations by reducing the RCS level to less than 50 inches above the centerline of the hot legs. The inspectors attended the pre-job briefing, discussed the procedure and its adherence with the operators, and were present in the control room during draining operations until the RCS level stabilized at 19 inches above the centerline of the hot legs. The inspectors observed that licensee controls of electrical power, containment closure, RCS level indication, exit thermocouples, RCS makeup capability, and RCS vent path met licensee procedural and regulatory requirements. The inspectors also observed that the operators routinely referred to their procedure and careful oversight by both senior reactor operators and licensee management.

c. <u>Conclusions</u>

Failure to follow procedure during preparation for Unit 3 drain activities resulted in the loss of approximately 400 gallons from the reactor coolant system and was considered a non-cited violation **(Recovery Plan Item P1)**.

Unit 3 reduced inventory operations were completed properly with appropriate operator action, supervisory oversight, and procedure adherence.

O1.3 <u>Unit 2 Reactor Trip</u>

a. <u>Inspection Scope (93702, 92901, 71750)</u>

On November 3, 1998, at 10:15 a.m., the Unit 2 reactor tripped from 100 percent power when the main turbine and main feedwater pumps tripped because of a steam generator high level signal. The inspectors responded to the control room and general plant areas to observe licensee actions in response to the trip and post-trip recovery.

b. <u>Observations and Findings</u>

When the inspectors arrived at the Unit 2 control room, the plant was in a stable condition with all rods in the core. Operations personnel were methodically following their emergency operating procedures with good command and control. Operations verified that the steam safety relief valves had reseated after opening. The inspectors independently verified this by observing the valves and stable main steam line pressure with bypass valves in operation. All equipment operated as required with appropriate operator actions having been taken. The turbine first out panel had a high steam generator level annunciator lit. Operations and the inspectors independently reviewed the trend data on steam generator levels and found that no high level had occurred. Additionally, the operators reported a direct current (DC) ground annunciator light/alarm on buses 2CA and 2CB about four minutes prior to the trip. They were responding to those alarms when the trip occurred.

A post-trip review was methodically performed by the licensee and action plans were properly laid out with contingencies. With the inspectors present, initial investigations of relays in the steam generator overfill protection circuit found them still energized, which indicated that the ground was in that circuit. The licensee determined that the energization of these relays would trip both the main feed pumps and the turbine.

Personnel were interviewed regarding on-going work in the unit's cable spreading room. It was discovered that a fire protection penetration repair worker had improperly used a nail that damaged the cable to the overfill protection circuit. He had placed a board over a cable penetration containing the subject circuit's cable. The worker used a hammer to seat the board over the penetration entry and in so doing shorted the cable to ground.

With an inspector present, the cable was replaced and satisfactorily tested. The unit's operations personnel began the re-start check list on November 4, 1998. The plant review committee met later that day to review the trip and repair details. The inspectors attended the meeting, finding the proceeding appropriate for the problem and then observed the satisfactory post-repair testing. The event is addressed in Unit 2 licensee event report (LER) 50-270/98-07, Reactor Trip on Main Feedwater Pump and Main Turbine Trip. Additional NRC followup will be performed in the closeout of this LER.

c. Conclusions

With Unit 2 at 100 percent power, an incorrect repair of an electrical penetration fire sealant resulted in a direct current ground that caused inadvertent main feedwater pump and main turbine trips with an ensuing reactor trip. The plant equipment responded as expected to the trip. Operator response to the event was excellent. The corrective action activities in troubleshooting, replacing the damaged cable associated with the Unit 2 reactor trip, and the post-repair testing were also excellent.

O2 Operational Status of Facilities and Equipment

O2.1 Operations Clearances (71707)

The inspectors reviewed the following clearances during the inspection period:

- 98-4226 Unit 2 Main Generator Rectifier
- 98-4256 Keowee Unit 2 Battery Service Test
- 98-3565 3HP-26
- 98-3723 3LPSW-9

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

The inspectors also reviewed the following clearances that were no longer in effect during the inspection period:

- 98-4063 2MS-93 Solenoid Replacement
- 98-4067 Electrical PM on 2LPSW-137 Operator
- 98-4209 Paint EFDWPT Oil Cooling Water Pump

The inspectors observed that the equipment was returned to service appropriately and that the tags were removed.

O2.2 Engineered Safety Feature (ESF) System Walkdown (71707)

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

- Units 1 and 2 ESF Switchgear
- Units 1 and 2 Low Pressure Service Water (LPSW)

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.

O2.3 Human Performance During Engineered Safeguards (ES) Testing (Recovery Plan Item P1)

a. Inspection Scope (71707)

On November 18, 1998, during performance of ES testing on Unit 3, the licensee started Keowee Hydro Unit 2 (KHU-2) for weekly preventive maintenance checks. This resulted in the unexpected closure of standby bus tie breaker SK2. The inspectors reviewed the circumstances surrounding this event.

b. Observations and Findings

Operations test personnel in Unit 3 were performing procedure PT/3/A/0202/012, Component Test of ES Channels 1 & 2, Revision 5, and had tripped ES Channel 2 as part of the test. KHU-2 which was aligned to the underground emergency power path, was started in accordance with routine surveillance Procedure PT/2/A/2200/001, KHU-2 Weekly Surveillance, Revision 6, with the ES signal present. Breaker SK2 closed when KHU-2 reached the proper voltage and frequency in order to energize the standby bus. Breaker SK2 closed as designed, in that an ES signal and a live line-dead bus condition existed at the same time. In response to this unexpected breaker closing, operations personnel suspended the ES testing, performed a successful operability check on the underground power path, and opened breaker SK2. The licensee entered this into the corrective action program under PIP 0-O98-5569.

Procedure PT/3/A/0202/012 contained an initial condition that the Keowee unit connected to the underground power path be secured for the express purpose of preventing the SK breakers from closing. Test personnel verified this initial condition on November 17, 1998, but operators started KHU-2 locally on November 18, 1998, without informing ES test personnel. The inspectors determined this was not in compliance with procedure PT/3/A/0202/012.

The licensee determined that breaker SK2 unexpectedly closed because inappropriate action by the operators allowed both procedures to be performed simultaneously. The licensee took immediate corrective action to: place Procedure PT/1,2,3/A/0202/12 on administrative hold, generated an operations guide to have SROs review ES and electrical testing to prevent test conflicts, generated an operations guide to Keowee operators to notify the Oconee control room on any KHU start, and initiated operator training on this event and electrical system protection circuitry.

The licensee planned long-term corrective actions to: develop a matrix outlining the interactions among ES, emergency power switching logic (EPSL), degraded grid, switchyard, and Keowee protection circuitry; provide operator requalification training regarding these interactions; and evaluate different work scheduling options to prevent further interactions.

Violation 50-269,270,287/97-16-01: Failure to Implement Nuclear Systems Directive 408, described a similar event on December 1, 1997, when breaker SK1 unexpectedly closed during ES testing on Unit 1. One corrective action for that event indicated that an operations guide was issued to require review of ES and electrical testing to prevent simultaneous testing. Another corrective action stated that operators would receive training to ensure they understood the interactions among ES, breaker logic, and Keowee. The inspectors reviewed these corrective actions and found that the operations guide had been replaced with changes to procedures and that the training, while planned, may not yet have started. This will be left unresolved pending NRC understanding of (1) why the operations guide was removed and what procedure changes replaced it and, (2) whether or not any training on the event described in Violation 50-269,270,287/97-16-01 has occurred. This is identified as Unresolved Item (URI) 50-269,270,287/98-10-02: Inappropriate Action Results in Unexpected ES Component Actuation.

c. Conclusions

Simultaneous testing of an engineered safeguards channel and a Keowee hydro unit resulted in an unexpected actuation of an engineered safeguards component, but was left unresolved pending further NRC review of licensee corrective actions for a previous similar event. Recovery Plan Item P1 remains open.

O2.4 Unit 3 Low Pressure Injection (LPI) Pump Problems

a. Inspection Scope (62707, 61726, 37551)

During minor repairs to the Unit 3 LPI pumps, the licensee discovered other more significant problems with the pumps. The inspectors inspected the disassembled pumps, looked at the dimensional data and vibration data taken on the units, and discussed the problems with the licensee.

b. Observations and Findings

Both pumps' rotating elements had evidence of mechanical looseness. The 3A LPI pump had a suction wearing ring that had moved toward the pump suction piping about 1/4-inch. One of three wearing locking screws was still holding the ring on the impeller and it had not made contact with the pump casing. The 3B LPI pump had a less than required installation torque on its locking nut and evidence that the impeller had shifted on its key in the shaft keyway and had wedged tight. Removal of the impeller required significant pulling force. Inspector review of the pumps' vibration data indicated that there had been no noteworthy change in vibrations from 1993 to the present. Pump performance had not degraded. The 3B pump had been overhauled in 1985 and the 3A pump had never been overhauled. The licensee's evaluation (documented in PIP 98-5204) did not indicate a past operability concern, but recommended inspection (overhaul) of the other units' LPI pumps. The licensee plans to rebuild the three available spare rotating assemblies and overhaul the other units' pumps as schedule permits. This would begin during the June 1999 Unit 1 refueling. The Unit 3 pumps were observed to be properly repaired and test results indicated satisfactory performance.

c. Conclusions

Licensee inspection of the Unit 3 LPI pumps revealed several rotating element problems. Those were properly repaired and documented. The licensee plans to examine the other units' pumps as soon as practical.

O2.5 Top Equipment Problems Resolution (TEPR) (Recovery Plan Item SE3)

a. Inspection Scope (37551, 71707, 40500)

Under the Operational Review section of the August 5, 1997, Recovery Plan, three operational issues were discussed. Included in that section was a list of equipment that had known recurring problems. This list was generated by operations and was mostly recognized work-arounds. Although other Duke sites had a TEPR list that included work-arounds, no TEPR program had been established at Oconee. The inspectors examined the recently instituted Oconee TEPR program and the actions taken with the associated equipment list.

b. Observations and Findings

The licensee has implemented the TEPR program as described in Oconee Nuclear Site Directive 2.1.7, Top Equipment Problem Resolution Process, issued November 12, 1997. The TEPR program was verified to be more inclusive than the original recovery plan list (i.e., action register, work-around, and major equipment problem resolution lists). The program had assigned actions for the equipment under the list. Entry onto and removal from the list was based on specific criteria. Site management reviewed the TEPR output on a regular basis.

The inspectors sampled the list identified in the recovery plan, finding (with one exception) that corrective actions had been taken, were scheduled, or the problem had been deleted as non-specific. Long-term plant problems that had been present for years had been addressed and design changes implemented. Examples of these were: the concentrated boric acid pumps were being replaced on Unit 3 with a schedule of implementation for the other units; resistance temperature detectors in the RCS piping were being replaced on Unit 3 with a schedule for future implementation; and loose parts monitor reliability had been improved.

The above identified exception was a potential modification. N-16 steam line radiation detectors had been on the recovery plan list, but was not included in a tracking system. The addition of the N-16 monitors would be an enhancement to an existing two detector arrangement, offering continuous and faster detection capability. Engineering was to issue a modification action request form to have the detectors considered for future funding; the inspectors considered the lack of action on this issue was not a detriment to the new process. The licensee was proceeding with the modification as an option.

Equipment problems not on the original recovery plan list were also being identified for replacement or enhancement under the TEPR program. Examples of these items are the upgrade to the steam admission valves for the steam driven emergency feedwater pumps, letdown storage tank (LDST) to borated water storage tank (BWST) valve interlock circuitry; and general motor replacements and overhauls (heater drain motors, low pressure service water motors, and RCP motors).

The TEPR process was viable and functioned to bring about improvements in equipment reliability and operator work-arounds.

c. Conclusions

The Top Equipment Problem Resolution process has been fully implemented at Oconee and meets the Recovery Plan goals by functioning to bring about improvements in equipment reliability and operator work-arounds. Recovery Plan Item SE3 is closed.

O2.6 Unit 1 LPSW Flow Instrumentation to the LPI Decay Heat Removal Coolers Out of Service (OOS) Beyond Limiting Condition for Operation (LCO) Time Limit

a. Inspection Scope (71707)

During the past period, the licensee discovered both LPSW flow instruments for Unit 1 and 2 OOS. The inspectors followed the licensee's activities regarding the occurrence.

b. Observations and Findings

On September 9, 1998, the licensee found the Train A LPSW flow chart recorder failed high. The operators did not believe that the recorder problem affected the flow gauges associated with the flow measurement string. Corrective recorder repair began October 2, 1998. While that work was in progress, the Train B pen on the same recorder failed high. During troubleshooting, the licensee determined that the gauges used to monitor flow to the decay heat coolers were also failed due to grounding problems in the chart recorder. At that point, the licensee entered a LCO for TS 3.3.7, which is 72 hours in length for one flow string. Both flow instrument strings were returned to operable state on October 3, 1998. A record review indicated that the "A" train string had been inoperable since September 9, 1998. Due to a lack of licensee knowledge and attendant training issues, this was not obvious to the operators.

Due to a design problem, the trains of instrumentation did not have the independence originally believed by the operations staff. This issue was explored in Revision 1 to associated LER 50-269/98-13, Limiting Condition for Operation Exceeded on Low Pressure Service Water System Due to Inadequate Design Interface, dated November 23, 1998. The inspectors agreed with the presentation of the facts in the LER. The instrument wiring entered the recorder and was capable of being shorted out and failing the instruments. The operators had been trained that a light at the zero position on the flow gauges was an indication of proper operation. What was not known by the operators was that a blinking light at the zero position may be indicative of a ground problem. An operations guide was issued to explain this point and provide a alternate source of data to check the flow indication correctness. The inspectors will follow this occurrence, including the appropriateness of the LCO entries, with corrective actions specified in LER 50-269/98-13.

c. Conclusions

Through a review of records, the licensee discovered that Unit 1 exceeded a 72 hour limiting condition for operation for low pressure service water flow instrumentation to the low pressure injection decay heat coolers. The inspectors will evaluate potential enforcement through review of the associated licensee event report.

O3 Operations Procedures and Documentation

O3.1 Inadequate Labeling Renders Standby Bus Number 2 Inoperable

a. Inspection Scope (71707)

The inspectors interviewed personnel, reviewed procedures, and observed breaker and fuse conditions in the affected breaker enclosures following inadvertent licensee actions that rendered Standby Bus Number 2 inoperable.

b. Observations and Findings

On October 30, 1998, a non-licensed operator (NLO) was sent to remove the Unit 3 Main Feeder Bus Number 2 from service using procedure OP/0/A/1107/07, Removal and Restoration of Station Equipment, Revision 4. The NLO racked out the breaker and then questioned the Work Control Center Senior Reactor Operator (WCCSRO) on the number of fuse blocks to remove. This breaker contained three fuse blocks while other breakers of this same type only contained two fuse blocks. The WCCSRO directed the NLO to pull all three fuse blocks at 4:02 p.m.

In a subsequent update with the Operations Shift Manager (OSM), the WCCSRO discussed the three fuses and the OSM realized that the third set of fuses may impact the emergency power switching logic (EPSL) lockout circuits. After discussion with electrical maintenance personnel it was determined that with the fuse block removed and the lockout circuit for standby bus Number 2 inoperable, a fault on standby bus Number 2 could affect standby bus Number 1. This placed Oconee Units 1 and 2 in an unplanned 72-hour LCO, Technical Specification 3.7.1. The fuse block was reinstalled at 5:02 p.m. and the KHUs were tested satisfactorily at 5:52 p.m. The Oconee units exited the 72-hour LCO and operations initiated PIP 0-O98-5190.

The fuse blocks were not labeled as to their function. Hence, this was a violation of NSD 503, Labeling Standard, Revision 1, in that the fuse block labeling in this isolated case did not prevent confusion. The NLO displayed a good questioning attitude when confronted with an unknown situation. The WCCSRO failed to adequately assess the question of three fuse blocks and could potentially have prevented this event. The licensee has adequately labeled the affected breakers and has researched other breaker fuse labeling concerns. 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 50-269,270,287/98-10-03: Inadequate Fuse Labeling Results in Standby Bus Inoperability.

c. Conclusions

The failure to adequately label fuse blocks in the standby bus breakers and a lack of a questioning attitude on the part of the WCCSRO resulted in inoperability of the standby busses and was identified as a non-cited violation.

The good questioning attitude by the NLO was seen as a positive. The corrective actions taken to label the fuse blocks was also seen as a positive.

O4 Operator Knowledge and Performance

O4.1 Unit 3 Refueling Activities

a. Inspection Scope (71707)

Between October 21, 1998, and October 25, 1998, the licensee removed all fuel from Unit 3. Between November 5, 1998, and November 9, 1998, the licensee refueled Unit 3. The inspectors observed portions of these fuel movement activities.

b. Observations and Findings

The inspectors observed fuel movement activities in the control room, spent fuel pool (SFP), and RB. Procedures were available at each location and were adequate to meet all requirements of TS and the Oconee Shutdown Protection Plan. Fuel movement personnel referred to the procedures frequently. Constant communication was maintained among the various locations such that operators in the control room were aware of the movement of each fuel assembly by number. Control room operators and fuel movement personnel also monitored nuclear instrumentation as each assembly was installed. The inspectors also reviewed tapes of the debris scan and core verification scan. No items were identified for followup.

c. Conclusions

Fuel movement activities on Unit 3 were conducted in a professional manner with adequate procedures and good adherence to procedures.

O4.2 Management Observations of Operating Shifts (Recovery Plan Item TD1)

a. Inspection Scope (71707)

The inspectors reviewed the Recovery Plan, interviewed responsible managers, and reviewed documentation for the Management Observations Temporary Defense.

b. Observations and Findings

As part of the Oconee Recovery Plan, the licensee initiated three temporary defenses to prevent events. One of the temporary defenses was for operations management to conduct six hours per shift of direct observation during non-outage time. In February 1998 the Management Observation Temporary Defense was replaced by Assessment, SA-98-117 (ON)(PA) Oconee Control Room Activities. The other two temporary defenses (i.e., management oversight during startup/shutdown and inventory monitoring enhancements) were discussed in Inspection Report (IR) 50-269,270,287/98-06.

The inspectors verified that management observations were made for different shift positions in all units and that observations were fed back to control room personnel. The inspectors verified that assessment performed under Assessment SA-98-117 were similar to those performed under the temporary defense. In fact, the inspectors observed that Assessment SA-98-117 actually involved a more detailed assessment of the operating shifts. The recommendations from the assessment were also entered into the licensee's corrective action program via PIP 0-O98-2900. This initiative is closed.

c. Conclusions

The licensee's implementation of temporary defenses from the Oconee Recovery Plan for management observations during non-outage times was detailed, met the objectives outlined in the Recovery Plan, and were appropriately entered into the corrective action program. Recovery Plan Item TD1 is closed.

O8 Miscellaneous Operations Issues (92901, 92700)

O8.1 (Closed) LER 50-270/98-06: Two Trains of Essential Siphon Vacuum (ESV) System Inoperable Due To Ineffective Corrective Action

This event was initially addressed in IR 50-269,270,287/98-08 under Section O1.5, Licensee 10 CFR 50.72 Notifications. In this event both trains of the Unit 2 ESV system were made inoperable when the suction block valve for train A was left closed while train B was removed from service for testing. The licensee determined the cause of the event to be a deficiency in procedure PT/2/A/0261/010, Essential Siphon Vacuum Test, Revision 1. The procedure did not contain the appropriate steps to reopen the ESV suction block valves after they were closed for testing. Corrective actions, as addressed in the LER, included: correcting the procedure; counseling and training of involved individuals, as well as procedure writers and reviewers; review and revise the operations procedure validation process; and development of a detailed technical issues checklist.

The inspectors reviewed the LER and agreed with the licensee's assessment that the procedure had been inadequately upgraded from an engineering test procedure to an operations performance test. Corrective actions for a previous instance addressed in the LER were not specific enough to consider the subject occurrence as repetitive. Accordingly, 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 50-270/98-10-04: Inadequate Procedure Results in Valve Mispositioning. The subject LER is considered closed.

O8.2 (Closed) URI 50-270,287/98-06-03: Unit 2 and 3 RC Makeup Pump Past Operability

This URI was opened to determine if use of calculated RCP seal return flow based on upper cavity seal pressure would affect the data obtained in procedures PT/2&3/0600/010, RCS Leakage. The inspectors reviewed the past operability evaluation performed for PIP 0-O98-2765 and reviewed some past data from procedures PT/2&3/0600/010. The inspectors agreed that Unit 2 and 3 RC makeup pump operability determinations in procedures PT/2&3/0600/010 were not affected by the use of calculated RCP seal return flow. Based on this determination, there was no violation of regulatory requirements. This URI is closed.

O8.3 (Closed) Violation (VIO) 50-269, 270, 287/97-14-07: Unqualified Thermal Insulation Found in the Reactor Building

The licensee has completed all the required actions identified in the response to the violation dated December 17, 1997. The inspectors verified that the new or modified procedures have been issued. Additionally, the inspectors have inspected the containments on all three units looking for prohibited insulation and did not identify any additional material. Further, the inspectors reviewed and found acceptable the PIPs that documented the licensee's insulation inspections in the Units 2 and 3 containments that had been committed to in the violation response. This item is closed.

O8.4 (Open) Inspector Followup Item (IFI) 50-269, 270, 287/97-12-04: Maintenance Oversight

(Open) URI 50-269, 270, 287/98-06-04: Unit 2 Valve Misposition Issues

Both of these items have remaining licensee PIP corrective actions to be scheduled and completed. The inspectors reviewed the status of the actions, finding them incomplete at this point. Particularly, the longer term actions of the unresolved item have yet to be completed (e.g., PIP 0-O98-2654). These items are left open pending subsequent NRC review.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

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

•	WO 980133163	CF-11 Seat Leak
•	WO 98045463	Disassemble/Inspect 3CF-12
•	WO 980133263	CF-13 Seat Leak
•	WO 98045461	Disassemble/Assemble 3CF-14
•	WO 98015502	Unit 3, Refuel Reactor
•	OP/0/A/1506/001	Fuel Handling Procedure, Revision 79
•	PT/1/A/0202/11	HPI Pump Test, Revision 57
•	PT/2/A/0600/25	MDEFW Pump Arc Valve Test, Revision 04
•	OP/2/A/1106/002	Condensate and Feedwater System, Enclosure 3.65, Isolation of Main Steam to 2B FDWPT, Revision 125
•	PT/3/A/0251/027	High Pressure Injection Pump Developed Head Test, Revision 003
•	WO 98095663	Unit 2 Main Generator Rectifier Cooling Leak
•	IP/1/A/0400/11	Keowee Hydro Station 125V DC Instrument and Control Battery Bank No. 1 Service Test and Annual Surveillance, Revision 18
•	IP/0/A/3000/13	Cleaning/Inspection of Battery Cell Terminals and Inter-Cell Connections, Revision 10 (Keowee batteries)
•	IP/0/A/3000/26	Battery Cell Connection Resistance Test, Revision 07 (Keowee batteries)
•	WO 97105264	Perform Keowee Battery Preventive Maintenance and Discharge Test
•	TN/3/A/2983/AL1	Sections 4.12 thru 4.25, Post Modification Test for 7KV Upgrade, Revision 0

- PT/3/A/0610/01B — Emergency Power Switching Logic Startup Source Voltage Sensing Circuit, Revision 15
- PT/3/A/0610/01J — Emergency Power Switching Logic Functional Test, Revision 29
- WO 98098844-01 — Troubleshoot 4160V Breaker Sync Check Relays
- PT/O/A/0610/17 — Operability Test of 4160V Breakers, Revision 12
- IP/0/A/4980/25B — Westinghouse CVE-1 Relay Test, Revision 10

b. Observations and Findings

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

The cooling water leak repair on one of four rectifiers on the Unit 2 main generator was performed with the unit on line at rated power. The rectifier was disconnected from service and the inspector verified that the remaining three were adequate for rated power operation. The leak was not stopped but was diminished by one-half. Excellent setups for the repair, contingencies and precautions were initiated. Thermography was used to monitor the temperatures of the remaining rectifiers. The work was performed under direct operations and maintenance supervision. Permanent repairs were made during a forced outage on November 3, 1998.

The inspectors observed the EPSL tests referred to as the "B" and "J" tests. The performance of the tests was good. Deficiencies in the tests were identified and corrected. Additional comments on procedure quality are in section E2.3.

The NRC Keowee interim report, Table 3-2 (Items 7 and 8), discussed the electrical tripping of the units at power. During the EPSL "J" test the inspectors observed that the Keowee units were electrically tripped from a load of approximately 68 megawatts each and did not mechanically over speed trip. This was consistent with the report text.

c. Conclusion

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

The repair activities, established contingencies, the use of thermography, and supervisory oversight for a rectifier cooling water leak repair on the Unit 2 main generator were excellent.

The performance of the emergency power switching logic tests was good and the Keowee units did not mechanically overspeed trip when electrically tripped from 68 megawatts each.

M1.2 Unit 3 Core Flood Check Valve Maintenance

a. Inspection Scope (62707)

During the Unit 3 outage the licensee disassembled, inspected, reassembled, and tested Valves 3CF-11, 3CF-12, 3CF-13, and 3CF-14. The licensee installed a new disc and hinge arm in each valve except for 3CF-14. The inspectors observed portions of each phase of these jobs and checked all new parts for proper documentation.

b. Observations and Findings

The licensee used vendor personnel to perform this maintenance assisted by a licensee technician. The inspectors noted that the vendor personnel were very familiar with the valves and had much experience maintaining them. The vendor personnel had the procedure available in the field as they worked and new parts for each valve were properly identified in associated work orders with proper certifications. Vendor personnel were also careful to ensure that the correct parts were installed in each valve.

The inspectors reviewed Procedure MP/0/A/1200/058, Valve - Crane - Pressure Seal - Swing Check - Disassembly and Reassembly, Revision 19. The inspectors noted several minor weaknesses in the instructions to disassemble and assemble the bonnet. When questioned about these the licensee changed the procedure to correct them.

The inspectors also noted a difference between the method vendor personnel used to install the new disc and hinge arm in the valves and the method described in the procedure. This difference was that vendor personnel measured the clearance between the disc and hinge arm and added a specified additional clearance before final installation whereas the procedure did not require the clearance measurement. When questioned by the inspectors, licensee and vendor personnel agreed the method used by vendor personnel was preferable. They initiated PIP 3-O98-5234 and decided to change the procedure to include the additional measurements.

c. Conclusions

Overall, the level of maintenance on the Unit 3 core flood check valves was good as evidenced by procedure availability at the work site and the proper control of replacement parts. The use of vendor personnel to perform maintenance increased the experience level of the work force.

The procedure for assembly and disassembly of the Unit 3 core flood check valves contained some weaknesses in the instructions for removing and installing the bonnet and for installing the disc. Recovery Plan Item NRC7, Maintenance Procedures, remains open.

M1.3 Standby Power Supply Breaker to Main Feeder Bus (MFB) 1 (Unit 1)

a. Inspection Scope (62707)

Prior to removing the Unit 3, 4160V MFB 2 from service on October 29, 1998, an operability test of the standby supply breakers was performed. While performing the test, the Unit 1 MFB 1 supply breaker S1, which provided power from Keowee, failed to close. The inspectors observed, reviewed, and discussed with licensee operations, engineering, and maintenance personnel the activities associated with the breaker. Additional comments are in Section O1.1.

b. Observations and Findings

The initial troubleshooting indicated that the synchronization check (SYC) relay, device 25, on the S1 breaker was not operating. This prevented the breaker from closing manually or automatically. The relay prevents breaker closure if the sources of power are not synchronized. The relay was removed and a quantity of fine white whisker-like material was observed on relay components. A total of ten relays of this type are used in the standby power system. This relay type had been installed since plant startup and had been tested in-situ without the white material being observed. With Unit 3 in an outage, its corresponding SYC relay was removed and a smaller quantity of the white material was observed. The Unit 1 relay was made functional, tested (but not cleaned), and placed in the Unit 3 S2 breaker. The Unit 3 relay was placed in Unit 1 S1 breaker. An operability test was re-performed and all breakers closed and opened properly. Unit 3 MFB 2 was then removed from service for maintenance. The previously failed relay was subsequently removed and a minor modification was performed to install a replacement relay.

The licensee had developed and carried out a positive, controlling action plan to inspect and clean the SYC safety-related relays. Based on the fact that the licensee had no spare relays and the relays were obsolete, each relay was cleaned and returned to service. The licensee was developing another modification to replace all such relays.

The inspectors observed portions of the activities involving checking, cleaning, and calibrating the SYC relays. White material was observed in the other relays, but not as dense a coating as seen on the original failed relay. A sample of the material was taken for laboratory analysis. The inspectors verified that TS requirements and selected licensee commitments were met. The followup action plan and the initiation of a minor modification were considered appropriate corrective actions.

c. Conclusions

The synchronization checking relays were in poor condition and contributed to a standby bus breaker failure.

The followup action plan and the initiation of a minor modification to address the failed synchronization relay, which caused a failure of a breaker in the standby bus, were appropriate to address this degraded material condition.

M1.4 Inservice Inspection (ISI) - Unit 3 (Recovery Plan Item SE8)

a. Inspection Scope (73753)

The inspectors observed Unit 3 ISI activities and reviewed the results of ISI examinations.

b. Observations and Findings

The inspector reviewed the results of augmented ISI performed on the high pressure injection / make-up (HPI/MU) system nozzle connections to the reactor coolant system. The inspector reviewed radiographs of the HPI nozzles, compared those taken this outage with radiographs taken during the last outage, and agreed with the assessments made by the licensee that the gaps in nozzles 3B-1 and 3B-2 had not increased in length.

The inspectors witnessed the scheduled ISI, ultrasonic examination (UT) of the lower shell weld on the 3A steam generator, weld number 3-SGA-WG58-2. The weld was 100% UT inspected by three, two-person crews: one crew inspected using 0° and 70° transducers, another crew used a 35° transducer, and the third crew used a 45° transducer. A recordable indication was noted during the examination with the 35° transducer, but the indication was not confirmed by the 45° or the 70° scans, and location and metal-path measurements indicated that the reflector was outside of the area of interest for the weld being examined. Subsequent data evaluation by the licensee resolved the indication as a geometric reflector from the surface of the OTSG. The inspectors agreed with the licensee's assessment that the reflector found during the 35° UT scan was outside the area of interest and was also not an indication of a flaw in the OTSG base material. The only problem noted during the UT of the steam generator weld was a minor radiological control issue concerning the need for plastic suits to keep from soaking UT couplant through anti-contamination coveralls. The health physics technician assigned to that area of the containment sent two members of the UT crew out to change their anti-contamination coveralls after noting that their shoulders and back were dirty and/or wet from contact with the surface of the OTSG.

c. Conclusions

The results of the scheduled and augmented inservice inspection activities reviewed provided clear status of the components acceptability for continued service. This completes the NRC review of the Oconee ISI Defense Plan. Recovery Plan Item SE8 is closed.

M1.5 OTSG Inspections - Unit 3

a. Inspection Scope (50002)

The inspectors observed OTSG inspection activities, including eddy current (ET) data acquisition and evaluation, and primary side loose parts remote visual inspections.

b. Observations and Findings

The inspectors observed the ET data acquisition activities conducted on the Unit 3 OTSGs. The observations were conducted through observation at the work stations located on site. The inspectors noted that the licensee had contracted with Framatome Technology, Incorporated (FTI) to provide quality assurance oversight of the data acquisition operations. The inspectors reviewed the status of the oversight program with the FTI quality assurance auditor.

The inspectors observed ET data evaluation operations at the Duke Power Company ET facility located at the McGuire site. During the Oconee Unit 3 outage, the primary data analysts were located at the McGuire Site (Duke Power Company) and at San Onofree Nuclear Generating Station (ANATEC Corporation); the secondary analysts were located at Lynchburg, VA (FTI) and Benicia, CA (Rockridge); and resolution analysts were located at the McGuire site along with Qualified Data Analyst (QDA) oversight analysts.

On November 9, 1998, the inspectors noted that the licensee was engaged in extensive remote visual examinations of the B OTSG. When asked, the licensee informed the inspectors that the primary side of the OTSG was being searched for 136, 5/32-inch diameter, ball bearings which had come out of bearing races in a section of the ET inspection, manipulator mast. The licensee had generated PIP 3-O98-5304, to document the foreign material exclusion breach and to provide a vehicle for the required operability evaluation when at the conclusion of the search, 11 of the 136 ball bearings were unaccounted for. The inspectors reviewed the operability evaluation provided, and agreed with the licensee's conclusions that any bearing left inside the reactor coolant system would not result in an unacceptable risk to the reactor internals.

c. Conclusions

The licensee's eddy current examination activities were conducted in a conservative manner, with several levels of review during data analysis.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 Work Management Backlog (Recovery Plan Item OF5)

a. Inspection Scope (62700)

This portion of the inspection was conducted to review the recovery plan item concerning work order backlog. The item was included in the recovery plan due to the number of non-outage corrective maintenance tasks exceeding the average of best performing plants of approximately 120 work orders per unit. The age of these work orders was also a concern. The inspector reviewed the status of corrective actions regarding this issue, and discussed process improvements with the scheduling supervisor who had the lead on the item.

b. Observations and Findings

When the licensee began efforts to reduce the number and age of non-outage corrective maintenance work orders, the site had approximately 647 of these work orders open with 129 greater than 180 days old (for all three units). Goals for reducing these numbers were established by the licensee of less than 400 and less than 25, respectively. Review of this data at the time of the inspection determined that the number of non-outage corrective maintenance work orders had been reduced to 239, and the number greater than 180 days old had been reduced to 25, both of which met or exceeded the site goals. The progress in this area was discussed with the scheduling supervisor who attributed the progress to the following: (1) The site had implemented a morning meeting, that reviews all work orders issued in the previous 24 hours for proper prioritization in accordance with site procedures. This, coupled with improvements in up front loading of schedules in accordance with their priority, results in the work being performed in a more timely manner. (2) A review was performed of the older work orders to determine why they were not closed. It was found that many of the older work orders were essentially field complete, but had not been closed for administrative reasons. Actions were taken to resolve the issues and close those work orders. Changes in this scheduling philosophy were in the process of being included in the site's Work Management Guidelines to ensure permanent correction of this issue.

c. Conclusions

Corrective measures implemented as a part of the Oconee Recovery Plan Work Management Backlog issue were effectively implemented. Recovery Plan Item OF5 is closed.

M8.2 Outage Readiness (Recovery Plan Item OF6)

a. Inspection Scope (62700)

This portion of the inspection was conducted to review the recovery plan item concerning outage readiness. The item was included in the recovery plan in order to improve outage preparations in an effort to improve outage execution. The inspector reviewed the status of corrective actions regarding this issue, and discussed process improvements with one of the site outage managers.

b. Observations and Findings

Licensee Work Process Manual (WPM) 602, "Outage Management," Revision 3 includes pre-outage milestones, which are directed at improved planning of outages to ensure improved outage execution. These milestones include dates for such items as identification of outage modifications to be worked, issuance of modification packages, identification of outage preventative maintenance, issuance of work orders, ordering of materials, etc., WPM 602 indicates that outage preparations are to begin 18 months prior to the beginning of an outage. The licensee's recovery plan identified that outage planning needed to be improved. The inspector reviewed the status and progress made concerning this item with the following results. Outage planning for the last Unit 2 outage (conducted March 13 to May 24, 1998) began only three months prior to the start of the outage. Preparations for the current Unit 3 outage began in March 1998 (approximately 7 months ahead of the start date), and preparations for the upcoming Unit 1 (June 1999) and Unit 2 (November 1999) outages appear to be on track in accordance with the WPM. Review of adherence to the current revised Unit 3 milestone dates determined that nearly all dates had been met as scheduled. Review of critical path delays experienced during the current outage determined that they have been only minor in nature. Discussion of the current outage with the outage manager indicated that the recovery plan item had resulted in increased management focus, and notable improvements in outage execution, especially with regard to the outage valve work.

c. Conclusions

Corrective measures implemented as a part of the Oconee Recovery Plan Outage Readiness issue were effectively implemented. Recovery Plan Item OF6 is closed.

M8.3 (Closed) VIO 50-269,270,287/98-02-07: Failure to Implement Procedural Requirements Relative to Material Condition and Housekeeping Practices-Two Examples

This violation identified several housekeeping deficiencies and included three examples of prohibited power chemistry materials applied to stainless steel piping and components (paint, grey tape, and lagging adhesive). The licensee's corrective action for the violation included the following:

- Performed operability evaluations for all affected systems
- Cleaned affected areas cited in the violation and tested for chlorides and fluorides
- Conducted training concerning power chemistry materials with all insulation and coatings teams
- Tested paint, grey tape and lagging - paint contained no chlorides or fluorides, grey tape and lagging adhesive contained unacceptable quantities of chlorides and fluorides, and met class II requirements of the Power Chemistry Materials Program
- Removed, cleaned and tested many areas covered with grey tape
- Recalled and banned grey tape use at the site
- Identified and procured an alternate tape and an alternate lagging adhesive
- Conducted site wide training on the Power Chemistry Materials Program

- Developed and implemented safe procedures for removal of tape and lagging adhesive from stainless steel components

- Formed an inspection team to determine if the use of these materials was widespread, identify problem areas, and remove the lagging adhesive and grey tape from components using the approved process

- Conducted an assessment to determine the effectiveness of Power Chemistry Materials Program implementation

The inspector reviewed objective evidence of the completion of each of the above listed corrective actions. The inspector also conducted a walkdown in Unit 1 to determine progress of corrective actions. All items were found to be satisfactory with the exception of the removal of lagging adhesive which is discussed below. The inspection of the Oconee units, although not completed, has been completed on the most important areas of all three units including inside containment and most of the safety systems. The inspection was extensive in scope and has identified over 4500 deficiencies. As a result of this review, corrective actions were found to be adequately implemented and the violation is closed.

During the walkdown to close out this violation, lagging adhesive was found on the Unit 1 LPI pump 1A flange and flange fasteners, and the Unit 1 reactor building spray pump 1A flange and flange fasteners. Licensee personnel were questioned concerning this lagging adhesive, and it was determined that licensee personnel had made the decision not to remove lagging adhesive from all stainless steel piping and components. The inspector determined this to be contrary to the Power Chemistry Materials Guide, Revision 25, which requires removal of all class II material from stainless steel and nickel alloy surfaces prior to operation of the system above 200 degrees F and contrary to the licensee's corrective action response dated May 20, 1998, which implied that the adhesive would be removed. Based on discussion with licensee personnel, the inspector determined that a written evaluation providing the technical basis for acceptance of this condition had not been documented. Failure to remove lagging adhesive from stainless steel materials in accordance with the licensee's response to Violation 50-269,270,287/98-02-07 and as required by the Power Chemistry Materials Guide is identified as Violation 50-269,270,287/98-10-05, Inadequate Corrective Action Concerning Removal of Lagging Adhesive from Stainless Steel Piping and Components. After identification of this deficiency, the licensee identified additional corrective actions (i.e., further sampling and engineering analysis of documented results), which would be taken to resolve the issue.

These actions were documented in PIP 0-098-1037 (Items 13, 14, and 15), reviewed by the inspector, and found to be acceptable.

III. Engineering

E1 Conduct of Engineering

E1.1 Review of Nuclear Station Modification (NSM) Implementation

a. Inspection Scope (37550)

The inspectors performed a walk down of NSM ON-32885/00 to determine if it was implemented in accordance with the licensee's design change control program, appropriate NRC regulatory requirements, and licensing commitments.

b. Observations and Findings

This NSM replaced the non-safety-related level and pressure instrumentation channels for the LDST with safety-related Quality Assurance (QA) Condition 1 redundant instrumentation, and added an interlock between the LDST Lo-Lo Level signal and high pressure injection (HPI) pump suction supply from the BWST isolation valves, 3HP-24 and 3HP-25. This modification also incorporated appropriate recommendations from the HPI Reliability Study and implemented those commitments made to the NRC in response to Violation EA 97-298-01012. The inspector reviewed the final scope document for NSM ON-32885/00, Revision 2, and the associated 10 CFR 50.59 safety evaluation both dated June 18, 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.

The inspector reviewed and discussed the NSM package with the implementing engineers in the modifications department and then, accompanied by a modifications engineer, performed a walkdown inspection of portions of the completed modification. During the walkdown, the inspector noted several problems with wiring of different safety colors being in direct contact with each other. The problems were found inside terminal boxes TB2345 and TB2346, and in the back of the Unit 3 main control room board 3UB1 at LDST level and pressure indicators, 3HPI P0360 and 3HPI P0021, respectively. The separation problems inside the terminal boxes were between safety colored yellow and gray wires, while the control board panel separation problems involved safety colored blue and orange wires.

Terminal boxes TB2345 and TB2346 were installed as part of this modification in the Unit 3 cable room. Both a gray and a yellow cable were terminated in each box. The gray cable interfaced with the open control circuit of safety related HPI valve 3HP- 24 while the yellow cable interfaced with the redundant HPI valve 3HP-25. The gray (train A) and redundant yellow (train B) cables were separated outside each box, but inside the boxes the conductors had been bundled together and were in direct contact with each other. These cables were required to be physically separated. The other wiring separation problems were located in the Unit 3 main control board 3UB1 at the level and pressure indicators for the LDST, 3HPI P0360 and 3HPI P0021, respectively. Safety colored blue and orange conductors terminated at each indicator. Where the blue and orange conductors exited the flex conduit, near the indicators, separation was not maintained, and the blue conductors came in direct contact with the orange conductors.

Sections 5.3.4 and 7.0 of the Oconee Cable and Control Board Separation Criteria 0SS-0218.00-0019, Revision 3, prohibits cables of different colors from making contact with each other. The failure to assure adequate separation of different colored cables inside enclosures is a violation of 10 CFR 50 Appendix B, Criterion III, Design Control. This item is identified as Violation 50-287/98-10-06, Failure to Provide Separation of Redundant Safety-Related Cables Inside Enclosures.

The licensee initiated PIP 3-O98-5276 and made the necessary wiring changes to resolve the identified wiring deficiencies. The licensee also inspected other enclosures on Units 2 and 3 and found and corrected additional wiring separation problems between gray and yellow wiring inside Unit 3 panel 3ESVLCP. The licensee has also identified other needed corrective actions which include: (1) Revise and clarify separation criteria as described in OSS-0218.00-00-0019 to give guidance for enclosures; (2) Establish a representative inspection for safety related electrical work for the last 2 years to determine if the problem has been systematic; (3) Train modification engineering on the revised OSS-0218.00-00-0019; and (4) Train modification craft supervision and job sponsors on the revisions to OSS-0218.00-00-0019.

The inspectors found that other aspects of the modification had been performed satisfactorily. This included the development of adequate setpoint calculations and instrument calibration procedures for the LDST LO-LO Level interlock.

c. Conclusions

A violation was identified for failure to provide separation between redundant trains of safety-related cables inside two terminal boxes and a main control room panel during installation of Unit 3 Modification ON 32885/00.

The setpoint calculations and instrument calibration procedures for the LDST LO-LO Level interlock were adequate.

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 3 Reactor Coolant Pump (RCP) Inspections

a. Inspection Scope (37551)

The inspectors observed the RCP inspections and reviewed the operability analysis for the Unit 3 RCPs.

b. Observations and Findings

The licensee inspected the RCP 3B1 impeller as part of pump replacement during the outage and inspected RCPs 3A1 and 3A2 using a remote video camera. The licensee also amended the operability analysis in PIP 2-O98-1914 and concluded that the Unit 3 RCPs could operate indefinitely based on the extent of current cavitation. The inspectors reviewed the video and the operability analysis and found them to be acceptable

The licensee also made several procedure changes to limit Unit 3 RCP run time at low net positive suction head conditions and to provide operational curves for proper pump operation. The procedures were OP/3/A/1102/001, Controlling Procedure for Unit Startup, Revision 201; OP/3/A/1103/006, RCP Operation, Revision 27; and OP/0/A/1108/001, Curves and General Information, Revision 30. The inspectors reviewed these procedures and found them to be acceptable.

c. Conclusions

The operability analysis and inspections of the Unit 3 reactor coolant pumps were adequate.

E2.2 Keowee Breaker and EPSL Modifications and Replacements (Recovery Plan NRC6)

a. Inspection Scope (37551)

The inspectors reviewed, observed, and discussed with licensee personnel the activities involved with the KHU electrical breaker and previous EPSL modifications and replacements.

b. Observations and Findings

The KHU breaker modifications and replacements involved the air circuit breakers (ACB) and the Type DB 16F, DB 25, and DB 50 breakers. Among these were the following: the pneumatically operated output ACBs for the generators, ACBs 1 thru 4; the electrically operated power supply ACBs to auxiliary power switchgear, ACBs 5 thru 8; power supply breakers to the load centers; the field supply, the field, and field flashing breakers; and logic relays for selected breakers. The EPSL involved the RCPs. During an accident condition and a switchyard isolation signal from the EPSL with power from the KHU overhead to the startup transformer, the RCPs would transfer from the auxiliary transformer to the startup transformer. This could result in an overload of the KHU due to a transfer between non-paralleled electrical power sources. The condition was documented in Special IR 50-269,270,287/96-05. To resolve this problem, the licensee developed and installed several modifications.

The inspectors observed that five NSMs and four work orders (WO) were initiated as follows:

- NSM-32983, will insert logic circuitry that will interlock the RCP switchgear power from the startup source and the RCP breakers with the switchyard isolation logic. This will prevent the startup source breakers for the RCPs from closing and, if closed, trip the breakers during accident conditions.

- NSM-53049, will replace the electrical/mechanical type SV field relays, which are frequency sensitive, with solid state type SSV-T, which are not frequency sensitive. This concern was documented in the NRC Augmented Inspection Team (AIT) Report 50-269,270,287/97-11.

- NSM-53050, will replace the close control X-Y relay circuity in the old DB breakers with new equipment for the field supply, the field, and the field flashing breakers. The new breakers will have a new type of X relay close control scheme. The X-Y relay design, which have caused the KHUs to fail to start, was also documented in the AIT report.

- NSM-53051 and 53052 will do the same as NSM-53050 except that a total of 16 old DB breakers associated with the auxiliary power load centers 1X and 2X will be replaced with new breakers that have the new type X relay scheme.

- The WOs were initiated to change out ACBs 1 thru 8 with new breakers.

From discussions with licensee personnel and review of the NSMs and WOs, the inspectors determined that the modifications were initiated in accordance with approved procedures; the modifications were technically sound, easily understandable, and addressed the NRC concern; and where applicable, contained comprehensive post modification/maintenance testing. The NSMs and WOs are scheduled for implementation during outages and non-outage periods.

c. Conclusions

The modification for the reactor coolant pump switchgear was excellent, in that it was technically sound, easily understandable, and was installed in an excellent manner.

The modifications and replacements for the Keowee breakers are in progress or have been scheduled. The design, support, procedures, and processes used were good. Recovery Plan Item NRC6 is closed.

E2.3 Procedure Performance and Quality (Included Under Recovery Plan Item NRC7)

a. Inspection Scope (37551)

The inspectors reviewed and observed a modification and procedures involving the 7 kilovolt (KV) and the 4 KV power system EPSL.

b. Observations and Findings

The inspectors observed and reviewed the post-modification test (PMT) for NSM ON-32983, TN/3/A/32983/00/AL1, Installation of Electrical Components Associated with 7 KV Power System Upgrade, Revision 0. The performance of the test was excellent in that the following was observed: the prejob briefing was comprehensive and involved the correct personnel; the personnel performing the test were deliberate and cautious; the phonetic alphabet and three part communications were used; the test was stopped when an unexpected condition from an electrical ground arose; and test personnel identified procedure problems.

The test procedure was poor in that the following was observed: it did not provide for repeating steps if a relay or other device needed adjustment; relays were not verified as needing to be adjusted in the prerequisites for the test; and a minor change had to be made during the performance of the test. A poor EPSL procedure, referred to as the "B" test, was identified, in that the test had to be suspended due to similar problems. The procedure was changed, rescheduled, and subsequently performed with adequate technical support. A problem was identified with the EPSL test, referred to as the "J" test, in that a voltage reading was required and no voltage was present. The procedure problem that were identified before they created operational or equipment problems.

The inspectors determined from the reviews and observations that procedure quality does not meet the recovery plan objectives.

c. Conclusions

The performance of a test following modification of the 7 kilovolt power system was excellent in that personnel used effective communications, stopped the test for unexpected conditions, identified procedure problems, and were continually aware of equipment status at all times.

Test procedures were poorly written for a post-modification test of the 7 kilovolt and the emergency power switching logic systems. Recovery Plan Item NRC7 remains open.

E2.4 Witness of One-Time Design Verification Test on Emergency Power Supply (Keowee)

a. Inspection Scope (37550, 37551, 62707, 61726)

The inspectors witnessed a one-time design verification test of one Keowee Unit emergency starting and powering the safety-related loads of Unit 3. The purpose of the test was to obtain data to compare the relative merits of initially energizing loads at 90 percent voltage and frequency versus 60 percent voltage and frequency.

b. Observations and Findings

To obtain the necessary data, it was sufficient to test one Keowee unit delivering power for one nuclear unit's accident loads via the underground path. Keowee Unit 2 was aligned to the underground path, and accident conditions were simulated at Oconee Unit 3 since that unit was shutdown for refueling. System alignments and flow adjustments were implemented to very closely model the design basis loading.

As demonstrated in previous integrated testing, breaker control logic is such that loads are energized via the underground path when the Keowee unit reaches approximately 60 percent voltage and frequency during the starting period. This previous testing did demonstrate acceptable system performance. However, the licensee committed to investigate whether improved system performance could be obtained by having the transfer to emergency power supervised by voltage and frequency relays such that loads would be initially energized when the Keowee unit reaches 90 percent voltage and frequency during the starting period.

It was not obvious that this second method would be superior to the present design due to the fact that the Keowee units exhibit a significant frequency overshoot during the start period. It was already determined through test data and computer simulation that the time from the 90 percent voltage and frequency point to the 110 percent frequency point is about 3 seconds. The frequency continues to increase beyond 110 percent before the governor can act to reduce the speed.

Since motor output torque is proportional to the square of the ratio of voltage and frequency [V/f], the frequency overshoot period is characterized by a reduction in motor output torque. At the same time, pump torque requirements increase when frequency overshoots since pump torque varies directly as the square of the speed (frequency). These phenomena occur with both the present design and the proposed supervised method. However, the three second time between energization and significant frequency overshoot mentioned above inherent in the supervised method means that motors could still be in their acceleration period when the overshoot occurs, thus raising the question of whether motors would stall or protective relays operate.

Even if the system appeared to work correctly with the supervised transfer method during the test, data would be analyzed to determine which method was superior. Specifically, traces of motor starting transient current for each motor for both cases would be compared to determine which gave the most margin with regard to the overcurrent relay set point. Also, instantaneous volts per hertz throughout the motor acceleration period would be compared for the two cases to determine which method gave the most margin with regard to torque available for motor acceleration. It was anticipated that perhaps some motors would have more margin with one method while other motors would have more margin with the other method.

Digital instrumentation was installed to record instantaneous current at 19 points throughout the distribution system. Similarly, voltage was recorded at a sufficient number of points to allow calculation of power flows to various loads. Frequency would be calculated from the voltage data. In the first part of the test, one voltage and one frequency relay were installed via a temporary modification, then a simultaneous Loss of Offsite Power (LOOP)/Loss of Coolant Accident (LOCA) was simulated at Unit 3. This portion of the test obtained data on how the system behaves when loads are energized when the Keowee unit reaches 90 percent voltage and frequency. In the second part of the test, the temporary modification was removed. Then the simulated simultaneous LOOP/LOCA was initiated to obtain data on how the system would behave with the present design in a manner that would allow direct comparison of data from the two cases. The test was conducted under the control of Procedure TT/3/A/0610/030, Revision 01, Keowee Emergency Power and Engineered Safeguards Functional Test.

Inspectors witnessed the test from the Unit 3 main control room, the Keowee station control room and at Safety Parameter Display System (SPDS) monitors. The inspectors also reviewed the: preparations, issuance, and performance of Procedure TT/3/A/0610/30, Keowee Emergency Power and Engineered Safeguards Test; just in time training for affected shift teams; and the fabrication, testing, installation, and removal of the temporary modification. Two problems were encountered during performance of the test.

First, after the temporary modification was installed and as a preliminary step to the actual test, the Keowee units were manually started and automatically started to demonstrate operability of the units. During shutdown of KHU-1 from this operability run, the Keowee operator used the master select switch rather then the local stop switch to stop the unit. Use of the wrong switch resulted in simultaneous trip and close signals on the field flash and field flash supply breakers. This caused those breakers to trip free which in turn caused the close coils to remain energized for an extended period. This problem was detected by test personnel observing smoke at the switchgear. The test was delayed while the cause of the problem was confirmed, the damaged breakers replaced, and other corrective actions put in place. With KHU-2 out-of-service with the temporary modification and KHU-1 failing due to the error, both KHUs were considered inoperable. The inspectors observed the licensee's actions and followup. The inspectors will follow this event under LER 50-269/98-15, Keowee Test Events.

The second problem encountered was with the temporary modification itself. The logic of the control circuit with the voltage and frequency relays was such that 90 percent voltage and frequency were not only a permissive to allow closure of the SK breakers, but after closure, voltage or frequency excursions below 90 percent would immediately initiate tripping of the SK breakers and de energization of the loads. During the first attempt to run the test, as soon as the load was applied, voltage dipped below 90 percent. This caused a loss of power at the Unit 3 main feeder buses. Operators reclosed 230 KV breakers 28 and 30 to restore power within about 90 seconds. Good data was not obtained. This problem was overcome by installing a time delay relay to prevent tripping during the expected transient period.

After the first two problems described above were resolved, both parts of the test were successfully completed. The inspectors observed the following:

- Both Keowee units started and all major loads were energized and continued to run as designed.

- At no time during the evolution did RCS temperature go outside the prescribed limits of 75°F to 100°F. Pressurizer level remained within the prescribed limits.

- Based on examination of a sample of points, data acquisition was successful. It will not be possible to reach a final conclusion as to which design is superior until the data is analyzed over the next several months.

- The licensee made changes to the procedure after part one of the test was completed. The inspectors reviewed these changes, and found that they were enhancements and did not represent any real deficiency in the procedure used to start the test.

- After the first part of the test, the inspectors reviewed the Oconee Unit 3 Alarm Log Report and found that the entries reflected intended system performance. The inspectors reviewed the Unit 3, Keowee and 230 KV switchyard events recorder printouts from the first part of the test. The inspectors observed from the Keowee events recorder that the field flash breakers cycled shortly after the 90 percent voltage and frequency point was reached. While this did not interfere with proper system operation, the inspectors commented that cycling was not desirable because it could lead to the breakers going to the trip free condition as happened in the past. The cognizant engineers responded that they were aware that the field flash breakers would cycle in the frequency overshoot period. The cycling was a manifestation of the fact that the voltage relay controlling the field flash breaker was really a volts/hertz relay. The engineers stated this problem would be resolved when the new voltage relays, which will be independent of frequency, are installed in spring 1999. Actually, even with the new relays, some cycling may occur if the set point is 90 percent of rated voltage and the load is applied at 90 percent due to the transient hunting of about 90 percent that occurs as voltage regulator response to the step load.

- From the review and observations, the inspectors found the following: the procedure and the temporary modification were well written and were easily understood; the procedure was technically correct and was reviewed by qualified personnel; the procedure referenced applicable TS and selected licensee commitments (SLC); the temporary modification was fabricated in accordance with applicable drawings and the materials used were specified in the temporary modification package.

Testing was stopped and re-started several times. The inspectors attended all the pre-test briefings, and thereby learned what problems or anomalies had occurred during the test. Two additional issues indicate further followup is needed to resolve the issues.

First, shortly after the second problem occurred, the licensee found a problem with KHU-1. For only the second time since construction, a pressure tank float in the KHU-1 governor system collapsed (PIP 98-5607), technically failing that unit. Again, both KHUs were technically inoperable. While the immediate problem was corrected, the root cause should be determined. The inspectors were on hand to observed problem discovery and its resolution. The inspectors will follow this event via the same LER indicated above.

Second, the current trace for valve 3LP-17, Low Pressure Injection System injection valve, indicated that some contact chatter may have taken place. Phase C current was definitely erratic. The valve did go to the open position as designed. Both these issues will be further inspected by the NRC under Inspector Followup Item (IFI) 50-287/98-10-07: Followup on Valve 3LP-17 Erratic Current Trace.

c. <u>Conclusions</u>

During post-modification testing of the minor temporary modification for the Keowee emergency test, a wrong switch was manipulated which resulted in both Keowee units being inoperable.

The Keowee emergency start test procedure was well written, technically correct, and the overall activities involved with the test performance were excellent.

A weakness in the design of the temporary modification for the Keowee Unit 2 emergency power test resulted in a test failure. An unrelated equipment failure on Keowee Unit 1 made both Keowee units technically inoperable.

During the Keowee test, motor operated valve 3LP-17 did not operate as expected. The licensee repaired the valve after the recent problem identification and is investigating.

E2.5 HPI System Review (Recovery Plan Item DB1)

a. Inspection Scope (37550)

The inspectors reviewed the licensee's implementation of the HPI System Initiative N9701 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 HPI System Review initiative was discussed in the Oconee Recovery Plan under the Management Focus Area of Design Basis. This initiative involved two phases. First, the licensee performed a reliability study of the HPI system. 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 inspectors focused on the first phase of the initiative during this inspection.

The HPI reliability study evaluated the current configuration of the system, considered the effects of potential modifications, and made recommendations on the optimum system alignments. The reliability study was reviewed and discussed in NRC IR 50-269,270,287/98-07. The IR indicated that two of the three recommendations from the reliability study had been completed and the remaining recommendation would be implemented by the licensee under NSMs for each of the three Oconee units. The implementation of the NSM (ON-32885/00) for Unit 3 was reviewed during this current inspection and is discussed in Section E1.1 of this IR. The same NSM (ON-12885/00 for Unit 1 and ON-22885/00 for Unit 2) will be implemented during the next refueling outages for Unit 1 and for Unit 2 which are currently scheduled for 1999.

c. Conclusion

The implementation of the first phase of the HPI System Review initiative was consistent with the scope and schedule described in the Oconee Recovery Plan. The corrective actions developed to address the three recommendations from the HPI System reliability study were adequate. Two of the three recommendations had been implemented. The third recommendation involved implementation of a nuclear station modification for each of the three Oconee units. The modification was implemented for Unit 3 during this current refueling outage and is scheduled for implementation during the 1999 refueling outages for Unit 1 and Unit 2. Recovery Plan Item DB1 is closed.

E2.6 Followup on Repairs to Reactor Building Protective Coatings (Recovery Plan Item NRC5)

a. Inspection Scope (37550)

The inspectors examined the repairs to the protective coatings in the Unit 3 reactor building which have been completed during the current refueling outage.

b. Findings and Observations

The licensee had initiated several PIPs to document and disposition deteriorated protective coatings in the Units 1, 2, and 3 reactor buildings. During the inspection documented in NRC IR number 50-269,270, 287/98-09, the inspectors accompanied licensee engineers and observed performance of a general visual walkdown inspection to examine the condition of the protective coatings inside the Unit 3 reactor building. The purpose of the walkdown inspection was to identify areas where coatings on the liner plate, concrete surfaces, or internal steel structures had deteriorated and to prepare plans for removal and repair of the deteriorated coatings during the current Unit 3 refueling outage. During the current inspection, the inspectors reviewed the licensee' procedures for application and inspection of coatings, and examined the repairs to the deteriorated coatings.

The inspectors reviewed the following procedures which control application and inspection of protective coatings:

- Nuclear Coatings Maintenance Manual, NCMM-1167.02, Revision 3 which provided the instructions for surface preparation, painting equipment, coatings materials, mixing and thinning of the coating materials, application, touch up, and inspection.

- Inspection Guide IG-1, which provided the inspection requirements for Service Level I coatings.

- Procedure QAC-1, Inspection of Field Applied Coatings, which provided detailed instructions for performance of inspections of coatings and documentation of inspection results.

The inspectors examined the coating repairs which had been completed during the current outage. Some work was still in progress. The following conditions were identified by the inspectors.

- New coatings had been applied to a small area (3 foot square) on the liner plate and on two structural steel beams near column B17 at elevation 850 over old coatings which had blistered.

- Coatings on the basement floor between the A and B cavities were cracked, peeling, or loose.

- A few areas on the liner plate and structural steel beams had loose coatings.

However, coatings repair work was still in progress during the inspection. Therefore, these areas may have been identified and repaired by the licensee's program.

The inspectors concluded that, with the exception of those areas discussed above, the licensee had repaired the deteriorated coatings in accordance with their procedures.

The inspectors questioned licensee engineers regarding inspection methods used to determine the thickness of the new coatings applied to repair areas and the maximum total thickness of all applications of coatings which could be applied to an area and still be within the limits tested under design basis accident (DBA) conditions. Discussions with license personnel disclosed that quality control inspections of the coatings were being documented on work orders (WMS documents) in accordance with instructions listed on Form QAF-1FA, dated December 5, 1994. The specific instructions on this form were to perform Categories 1 through 6 of the inspection requirements addressed in procedure QAC-3. These requirements include mixing and thinning of the coatings, surface preparation, prime coat application, intermediate and finish coat applications, and touch up (repair) of existing coatings. The inspectors reviewed the WMS documents for inspection of coating activities performed on October 24, 26, and 27, and November 1, 6, 11, and 15, 1998. Review of the records showed that the following information was either not documented or was incomplete: coating thickness, environmental conditions (dew point, surface temperature, humidity, and ambient temperature), batch numbers/lot numbers of coating materials, identification of measuring and test equipment, and identification of the inspection personnel. The failure to perform and document the quality control inspections of the Service Level I (safety-related) coatings in accordance with the requirements of procedure QAC-3 was identified as Apparent Violation (EEI) 50-287/98-10-08, Failure to Inspect and Document Inspections of Reactor Building Service Level I Safety Related Coatings. This apparent violation will remain open for a reasonable time to allow the licensee to develop corrective actions.

The inspectors also examined coating repairs at the liner/concrete floor intersection in the expansion joint area. This work included removal of a small portion of the concrete floor and measurement of the thickness of the liner plate using UT methods. The inspectors reviewed the UT results and verified that the liner had not corroded below the minimum wall thickness requirements.

The licensee's corporate coatings engineer discussed the issue regarding the maximum thickness of the coatings with the inspectors subsequent to the inspection. He indicated that the procedures will be revised to specify a limit for the maximum thickness for all coatings applied to an area to be within that specified in the DBA testing.

c. <u>Conclusions</u>

The licensee's coating repairs were adequate with the exception of some minor discrepancies. An apparent violation was identified for failure of the licensee's quality control inspectors to perform and document inspections of the coating repairs in accordance with quality control inspection procedures. Recovery Plan Item NRC5 remains open.

E2.7 Repairs to Cable Tray Support

a. Inspection Scope (37550)

The inspectors reviewed the licensee's corrective actions to address a potentially inadequate cable tray support.

b. Observations and Findings

On October 14, 1998, the inspectors identified a vertical cable tray support in the Unit 3 reactor building which did not appear to be adequately secured to the containment building structural steel. The support was tack welded to a steel beam. The licensee initiated PIP 0-O98-4955 to evaluate and disposition this issue. During the current inspection, the inspectors reviewed the licensee's initial evaluation and proposed corrective actions, which were documented in the problem description section of PIP report 0-O98-4955. This review disclosed that the licensee concluded that evaluation of the structural adequacy of the cable tray support could be delayed until the next Unit 3 refueling outage based on the existence of redundant safety related cables which would not be affected by failure of the cable tray. The inspectors discussed with licensee management the justification to delay evaluation of the structural adequacy of the cable tray support based on the existence of redundant equipment. As a result of these discussions, the licensee concluded that the cable tray support would be evaluated and repaired as required to comply with design criteria during the current Unit 3 outage. The licensee issued Minor Modification ONOE-13043 on November 19, 1998, to resolve this problem. This minor modification was implemented prior to Unit 3 restart.

c. Conclusions

The decision to delay performance of an operability evaluation of a potentially inadequate cable tray support based on the existence of redundant equipment was identified to the licensee as a weakness in the justification for delaying the evaluation of PIP report 0-O98-4955.

E2.8 Evaluation of Displacement of Main Steam (MS) Piping

a. Inspection Scope (37550)

The inspectors reviewed the licensee's corrective actions to disposition deformation of a portion of the main steam piping for the Unit 2 2B main feedwater turbine pump.

b. Observations and Findings

During performance of a walkdown inspection, licensee engineers identified that a portion of an 8-inch diameter main steam line which supplies steam to the Unit 2 2B feedwater pump appeared to be deformed. The licensee initiated PIP 2-O98-5309 to document and disposition this problem. The piping displacement was approximately 8 inches in the northward direction wherein the predicted displacement was in the south direction. Several rod hangers were observed to have excessive swing angles and a pipe saddle had moved almost completely off its support. Examination of the piping also showed that zero movement had occurred at support number 2-01A-2-0-1401A-SR1, which was a mechanical snubber. The licensee's initial assessment of the cause of the problem was that the snubber was locked up. However, functional testing of the snubber showed that snubber met acceptance criteria and was not locked up. Licensee engineers completed a new stress analysis which indicated movement should be in northward direction. Additional corrective actions planned included removal of insulation from pipe joints and elbows to examine the pipe welds and the piping in highly stressed areas such as at elbows. This work was in progress during the inspection. The licensee isolated the piping and removed it from service until corrective actions are completed.

The inspectors walked down the 8-inch diameter main steam piping which supplies steam to the main feedwater pumps on Units 1, 2 and 3. The piping examined include the lines supplying steam to the A and B pumps from the connection to the main steam lines to the proximity of the feedwater pumps. The inspectors noted that the piping and supports on the Unit 2 Train B showed indications of large thermal movements. During the walkdown the piping was at ambient temperature and was at a position of zero thermal deflection since it was isolated from the main steam system. The inspectors compared the pipe supports to the as-built pipe support drawings and verified the supports were constructed in accordance with design details indicated on the drawings. The inspectors also examined the supports and piping on Units 1 and 3 and on Unit 2 Train A and verified that similar conditions (excess pipe movements) did not exist on these lines. The inspectors noted that the design and construction of the piping from the main steam line to the feedwater pumps differed for each unit. The Unit 1 piping was supported from trapeze type supports which permits more flexibility and movement, while the Unit 3 piping had an expansion loop.

c. Conclusions

Identification and evaluation of the deformation/excessive movement of the main steam supply piping to the Unit 2B feedwater pump was a good example of proactive involvement of engineering support of facilities and equipment.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) VIO 50-269,270,287/97-02-05: Weld Undersized or Not Inspected by QA

This VIO identified several welds in spent fuel cask supporting structures of Horizontal Storage Module (HSM) E21 for independent spent fuel storage installation that were undersized and welds between the surge tank supporting legs and base plates that were not inspected as required by quality control (QC) inspectors. The violation response dated July 2, 1997, was reviewed and accepted by the NRC. The inspectors reviewed the root cause analysis and corrective actions in the response and discussed them with the licensee's engineers.

The licensee issued PIP 0-O97-1073 for root cause analysis and resolution of the undersized welds. The root cause was that the vendor's QC inspector used the average weld size as acceptance criteria instead of the required minimum weld size, and the licensee did not make an inspection while receiving the HSMs on site. The licensee immediately informed the cask system vendor, Vectra, and steel supporting structure vendor, HiTech, about the undersized weld problem. Both vendors sent QC inspectors to reinspect all the welds for eight HSMs on site. The reinspection confirmed that six percent of the total welds were undersized by 1/16-inch or less. Vectra issued Supplier Disposition Request 9-354-0026.05, Nonconformance Report QA100.NCR.1997, Corrective Action Report QA010.CAR.1997, and Calculation NUH004.0227, "Standard NUHOMS Prefabricated Module - Minimum Acceptable Weld Sizes" to evaluate and resolve the problem. The calculation demonstrated that all welds could be qualified as having a 1/16-inch undersize based on the stress requirements. The disposition of undersized welds was "use-as-is" based on the fact that no welds were undersized by greater than 1/16-inch. The inspectors reviewed documents and accepted the "use-as-is" disposition.

The licensee issued PIP 3-O97-1005 for root cause analysis and resolution of welds not inspected by QA. The licensee stated that the root cause for the QC inspectors not inspecting welds was due to unclear procedures and miscommunication between the acting supervisor and the engineer. The licensee revised the procedures and reinspected the welds and found some gaps, as large as 5/16-inch [between the weld base metals] were filled with weld material. In order to obtain the required weld sizes (gaps plus calculated weld sizes), the licensee issued a design change process for a modification to increase the weld size from 5/16-inch to 5/8-inch to account for the gaps. The inspectors measured installed new welds and found that all were acceptable.

Based on the licensee's evaluation and corrections, this VIO is closed.

E8.2 (Closed) IFI 50-269/97-18-07: Unit 1 Pressurizer Surge Line Drain Line Nozzle Loads Exceed Stress Analysis Limits

This IFI was issued for a review and verification that the subject nozzle had been or will be returned to compliance with code and design requirements. PIP 1-O98-0465 was issued to resolve the nozzle overstress problem. The inspectors reviewed PIP 1-O98-0465 and a portion of Appendix A, " Flaw Tolerance Evaluation for Surge Line Drain Line" of Calculation OSC-4349, "Piping Analysis Problem 1-59-05", Revision 4. The inspectors also discussed the problem with licensee engineering personnel. The licensee immediately performed a penetrant examination (PT) on the outer surface of the nozzle after the nozzle overstress was identified. No indications of cracks were found. The model used in calculation OSC-4349 assumed a possible crack in the nozzle as a worst case scenario and concluded that the nozzle still could safely be operated until the next refueling outage when the nozzle was schedule to be replaced. Work Order 98080264 was issued to replace the nozzle during the upcoming refueling outage in June 1999. The new nozzle will comply with design and code requirements. The inspectors agreed with the licensee's analysis and corrective actions. Based on the licensee's evaluation and the scheduled nozzle replacement in June 1999, the item is closed.

E8.3 (Closed) VIO 50-269, 270, 287/97-14-09: Failure to Conduct Post-Mod Testing on Keowee Over voltage Relay

The root cause of the violation was that the licensee's program did not require that changes to set points for all safety-related devices be processed under the modification process. The inspectors confirmed that the relevant site directive was revised to require that all safety-related set points be contained in the Equipment Data Base, and that changes to any set point shall be implemented under the modification process. The inspectors noted that Section 11.1 of the site directive now requires that should any set point be found to not be in the Equipment Data Base, that fact must be reported to the responsible engineer. The site directive should ensure that appropriate post-modification tests are specified whenever set point changes are made. The inspectors confirmed that the specific relay in question (K1 ELK RL 5331T) had been entered into the Equipment Data Base with a set point, and that the addition was performed under a modification (ONOE 10586). The inspectors confirmed that the Alarm and Set Point Document, which was being superceded by the Equipment Data Base, had not been revised since February 1997, the time the violation was identified. The inspectors reviewed the OEE-081 series of drawings which contain set points for most protective relays and found that it had only been revised under the modification process. The inspectors concluded that corrective actions for this violation were completed. Additional examples of similar problems could not be identified in a review of various relevant documents.

E8.4 (Open) IFI 50-269,287/98-05-03: Units 1 and 3 Low Pressure Service Water (LPSW) Testing

a. Inspection Scope (92903, 37550)

This IFI was identified for the NRC to review the LPSW system and related Oconee Service Water (OSW) project post-modification testing for Units 1 and 3. Similar testing for Unit 2 was reviewed and discussed in NRC IR 50-269,270,287/98-05 The inspectors reviewed this IFI and the Oconee Recovery Plan Item DB4 in order to observe portions of the Unit 3 emergency condenser circulating water (ECCW) and related system testing that was being performed during this Unit 3 refueling outage (RFO).

b. Observations and Findings

The inspectors reviewed the following test procedures related to the ECCW and LPSW testing:

- TT/3/A/0251/070, Siphon Seal Water Test, Revision 1
- TT/3/A/0261/009, ESV System Post Modification Test, Revision 0
- TT/3/A/0261/010, ECCW/ESV Integrated Post Modification Test, Revision 0
- PT/3/A/0251/023, LPSW Flow Test, Revision 9

The above procedures were reviewed for precautions and limitations, test acceptance criteria, and contingency planning. The procedures were also reviewed for consistency with the licensee's letter to the NRC (Proposed Revision to Technical Specifications for the Upgraded ECCW System Technical Specification Change Number 96-09) dated August 28, 1997, and the related NRC Safety Evaluation Report (SER) dated April 24, 1998. The inspectors noted that the test procedures were generally well written and required very few changes.

The inspectors attended the pre-job briefing and witnessed portions of the performance of test procedure PT/3/A/0251/023. The pre-job briefing was detailed with additional emphasis on the licensee's six tools of event free human performance. During discussions of this test with the inspectors, licensee personnel indicated that some of the ECCW testing was not being performed as described in the licensee's letter to the NRC dated August 28, 1997, and the related NRC SER dated April 24, 1998. The licensee had initiated PIP 3-O98-5386 to address this issue and submitted a letter to the NRC dated November 25, 1998, notifying the NRC of the commitment change for the ECCW testing. During performance of the testing, the inspectors noted that several discrepancies and/or deficiencies were documented by the licensee.

The inspectors also reviewed the test results for the above test procedures. The test acceptance criteria were met. Test deficiencies and discrepancies were documented for evaluation and resolution. The inspectors noted that retesting was required to resolve some of the test deficiencies where the acceptance criteria were not met initially. The inspectors noted that in PIP 3-O98-5386 the licensee had documented another instance where the testing was not performed as stated in the licensee's August 28, 1997 letter. This second test change involved the siphon seal water not being isolated to CCW pumps 3C and 3D during the ECCW Air In leakage Test. The licensee performed an analysis and calculation to address this change in the test acceptance criteria. The licensee submitted a letter to the NRC dated November 30, 1998, notifying the NRC of this second commitment change for the ECCW testing.

c. <u>Conclusion</u>

The inspectors concluded that the test procedures were generally well written and required only a few changes. The pre-job briefing was thorough. Test deficiencies and discrepancies were documented for evaluation and resolution. The test acceptance criteria were met or retesting was performed to resolve deficiencies where the test acceptance criteria were not met initially. The licensee submitted two letters to the NRC dated November 25 and 30, 1998, notifying the NRC of the commitment changes for the ECCW testing.

Implementation of the ECCW initiative was consistent with the scope and schedule described in the Oconee Recovery Plan. The testing to be performed for Unit 1 is similar to the testing that has been completed for Units 2 and 3. The Unit 1 testing is scheduled for the 1999 Unit 1 refueling outage. Inspector followup item 50-269,287/98-05-03 will remain open pending successful completion of the Unit 1 ECCW and related LPSW post-modification testing. Oconee Recovery Plan Item DB4 is considered closed. Further inspections of this item will be performed in conjunction with the above IFI.

E8.5 Review of Environmental Qualification for the Safety-Related 4 Kilovolt (KV) Switchgear in the Turbine Building (37550)

The inspectors reviewed the environmental qualification for the safety-related 4KV switchgear in the turbine building as part of the followup to IFI 50-269, 270, 287/ 98-08-05. The inspectors discussed with the licensee's corporate EQ engineer, the EQ of the 4 KV switchgear located in the turbine building. The inspectors also reviewed portions of Report No. OS-73.2 and Supplement Number 1 to the Safety Evaluation for Oconee Nuclear Station Units 2 and 3, 10CFR 50.49, and the NRC Guidelines for Evaluating Environmental Qualification of Class 1E Electrical Equipment in Operating Reactors (DOR Guidelines) dated November 1979. Based on this review, and discussions with the licensee, the inspectors concluded that the safety-related 4 KV switchgear located in the turbine building would be subject to steam impingement from a high energy line break event but that the overall turbine building would remain an EQ mild environment. However, the 4 KV switchgear was not required to be qualified for steam impingement from a high energy line break (HELB) because the licensee had proposed other mitigation strategies for the event that had been reviewed and accepted by NRC in the above Safety Evaluation Report. Therefore, in accordance with the EQ Rule and the DOR Guidelines, this equipment was not required to be EQ qualified to mitigate a HELB event.

IV. Plant Support Areas

R1 Radiological Protection and Chemistry Controls

R1.1 Radiological Protection

a. Inspection Scope (83750)

The inspectors reviewed personnel monitoring, radiological postings, high radiation area controls, posted radiation dose rates, contamination controls within the radiologically controlled area (RCA), and container labeling. In addition as low as reasonably achievable (ALARA) work planning, prejob worker briefings, and job execution observations were performed. The inspectors also reviewed licensee records of personnel radiation exposure and discussed ALARA program details, implementation and goals. Requirements for these areas were specified in 10 CFR 20 and TS.

b. Observations and Findings

The inspectors toured the health physics facilities, the auxiliary building, radioactive waste storage areas, turbine building and hot machine shop.

Records reviewed showed that the licensee was tracking and trending personnel contamination events (PCEs). The licensee had tracked approximately 301 PCEs for the 1998 calender year to date which included skin and clothing contaminations. There were 84 particle contamination events.

Radiologically controlled areas including radioactive material storage areas (RMSAs), high radiation areas, and locked high radiation areas were appropriately posted and radioactive material was appropriately stored and labeled.

The inspectors reviewed operational and administrative controls for entering the RCA and performing work. These controls included the use of radiation work permits (RWPs) to be reviewed and understood by workers prior to entering the RCA. The inspectors reviewed selected RWPs for adequacy of the radiation protection requirements based on work scope, location, and conditions. For the RWPs reviewed, the inspectors noted that appropriate protective clothing, and dosimetry were required. During tours of the plant, the inspectors observed personal dosimetry was being worn in the appropriate location. Previously identified poor radiation worker work practice corrective actions were reviewed. These included a videotape demonstrating specific radiation worker problem areas and additional guidance on the correct methods to be used by workers to avoid the practices. In order to determine the effectiveness of the radiation worker poor practices corrective actions, the inspectors observed workers entering and exiting the RCA. The inspectors observed continuing examples of poor radiation worker practices at the exit from the RCA at the Unit 3 health physics building and at the third level of the turbine building. The poor practices included numerous examples of hand carried materials (notebooks, files, prints, procedures, work packages) and back pocket items (gloves) that bypassed the small article monitor (SAM) frisking. Several workers piled materials into a single SAM which significantly reduced the likelihood of finding contamination on these objects. Requested rechecks determined that no contaminated material had exited the control point. Poor radiation worker practices continued after the enhanced training had occurred.

The inspectors reviewed the results of air samples that were taken during the Unit 3 reactor top of head control rod number 24 pull and Unit 3 reactor head pulling stators and number 24 lead screw (RWP number 3160) and determined that there was no transuranic activity present during these maintenance activities.

The inspectors reviewed in detail two RWPs for work on Unit 3 steam generators. The inspectors attended prejob briefings for the RWPs reviewed and observed the work activities in progress using closed circuit television. The Unit 3 containment job briefing area was observed to be small, noisy, and the briefer was often distracted by phone calls and job coverage information requests. The inspectors and some of the workers were not able to hear all of the information presented.

The inspectors discussed ALARA goals and annual exposures with licensee management and determined the organizational structure and responsibilities for the ALARA staff were clearly defined in organizational charts. The use of Unit 3 containment pre-job briefing area was observed to be congested, noisy, and distracting. Good chemical control during shutdown continued to reduce tube sheet dose rates by approximately 4.3 percent.

The Calender Year 1998 site exposure goal was set at 292 person-rem. At the time of the inspection (October 30, 1998), the site person-rem was estimated at about 262 person-rem. Approximately 88.4 person-rem of the estimated 160 person-rem had been accumulated as a result of Unit 3 refueling activities.

The inspectors reviewed the contaminated square footage data and observed that the licensee was tracking approximately 2775 square feet or about 2.2 percent of the controllable 126,091 square feet.

Conclusions

Radiological facility conditions in radioactive material storage areas, health physics facilities, turbine building and waste storage building were found appropriate and the areas were properly posted and material appropriately labeled. Personnel dosimetry devices were appropriately worn. Radiation work activities were appropriately planned. Continuing examples of poor radiation worker practices were observed. Corrective actions associated with previous poor radiation work practices had not been fully effective. The Unit 3 containment prejob briefing observed by the inspectors was not fully effective in communicating information to some workers. The use of the interactive video computer program for job planning was observed to be an ALARA strength. Good chemical control during shutdown continued to reduce tube sheet dose rates. Radiation worker doses were being maintained well below regulatory limits and the licensee was maintaining exposures ALARA.

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 December 2, 1998. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

X2 Pre-Decisional Enforcement Conference Summary

On June 22, 1998, a pre-decisional enforcement conference was held in the Regional Office with the licensee to discuss apparent violations (EEI) 50-269,270/98-12-01 and EEI 50-269,270/98-12-02, covered by EA Case No. 98-268. Following the conference, a NOV was issued to the licensee on August 5, 1998, for apparent violations EEI 50-269,270/98-12-01 and EEI 50-269,270/98-12-02. The violation cited in the NOV will be tracked as EA 98-268-01012, Failure to Meet Technical Specifications and 10 CFR 50.46 for Long Term Cooling. This violation was characterized as a Severity Level II problem. Based on the above, both EEIs are now considered closed.

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

IP37550	Engineering
IP37551	Onsite Engineering
IP40500	Effectiveness of Licensee Controls In Identifying and Preventing Problems
IP50002	Steam Generators
IP61726	Surveillance Observations
IP62700	Maintenance Program Implementation
IP62707	Maintenance Observations
IP71707	Plant Operations
IP71750	Plant Support Activities
IP73753	Inservice Inspection
IP83750	Occupational Radiation Exposure
IP92700	Onsite Followup of Written Event Reports
IP92901	Followup - Plant Operations
IP92902	Followup - Maintenance
IP92903	Followup - Engineering
IP92904	Followup-Plant Support
IP93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-287/98-10-01	NCV	Failure to Follow Procedure Results in Reactor Coolant System Inventory Loss (Section O1.2)
50-270/98-07-00	LER	Reactor Trip on Main Feedwater Pump and Main Turbine Trip (Section O1.3)

50-269,270,287/98-10-02	URI	Inappropriate Action Results in Unexpected ES Component Actuation (Section O2.3)
50-269/98-13-00 and -01	LER	Limiting Condition for Operation Exceeded on Low Pressure Service Water System Due to Inadequate Design Interface (Section O2.6)
50-269,270,287/98-10-03	NCV	Inadequate Fuse Labeling Results in Standby Bus Inoperability (Section O3.1)
50-270/98-10-04	NCV	Inadequate Procedure Results in Valve Mispositioning (Section O8.1)
50-269,270,287/98-10-05	VIO	Inadequate Corrective Action Concerning Removal of Lagging Adhesive from Stainless Steel Piping and Components (Section M8.3)
50-287/98-10-06	VIO	Failure to Provide Separation of Redundant Safety-Related Cables Inside Enclosures (Section E1.1)
50-287/98-10-07	IFI	Followup on Valve 3LP-17 Erratic Current Trace (Section E2.4)
50-269/98-15-00	LER	Keowee Test Events (Section E2.4)
50-287/98-10-08	EEI	Failure to Inspect and Document Inspections of Reactor Building Service Level I Safety Related Coatings (Section E2.6)
EA 98-268-01012	VIO	Failure to Meet Technical Specifications and 10 CFR 50.46 for Long Term Cooling (Section X2)
<u>Closed</u>		
50-270/98-06-00	LER	Two Trains of Essential Siphon Vacuum System Inoperable Due To Ineffective Corrective Action (Section O8.1)
50-270,287/98-06-03	URI	Unit 2 and 3 RC Makeup Pump Past Operability (Section O8.2)
50-269,270,287/97-14-07	VIO	Unqualified Thermal Insulation Found in the Reactor Building (Section O8.3)
50-269,270,287/98-02-07	VIO	Failure to Implement Procedural Requirements Relative to Material Condition and Housekeeping Practices -Two Examples (Section M8.3)
50-269,270,287/97-02-05	VIO	Weld Undersized or Not Inspected by QA (Section E8.1)

50-269/97-18-07-00	IFI	Unit 1 Pressurizer Surge Line Drain Line Nozzle Loads Exceed Stress Analysis Limits (Section E8.2)
50-269,270,287/97-14-09	VIO	Failure to Conduct Post-Mod Testing on Keowee Over voltage Relay (Section E8.3)
50-269,270/98-12-01	EEI	Failure to Meet TS and 10 CFR 50.46 for Long-Term Cooling Requirements (Section X2)
50-269,270/98-12-02	EEI	Failure to Meet Design Control Requirements of 10 CFR 50 Appendix B, Criterion III (Section X2)

Discussed

50-269,270,287/97-12-04	IFI	Maintenance Oversight (Section O8.4)
50-269,270,287/98-06-04	URI	Unit 2 Valve Misposition Issues (Section O8.4)
50-269,287/98-05-03	IFI	Units 1 and 3 LPSW Testing (Section E8.4)

List of Acronyms

ACB	Air Circuit Breakers
AIT	Augmented Inspection Team
ALARA	As Low As Reasonably Achievable
BWST	Borated Water Storage Tank
CFR	Code of Federal Regulations
DBA	Design Basis Accident
DC	Direct Current
ECCW	Emergency Condenser Circulating Water
EEI	Apparent Violation
EFW	Emergency Feedwater
EPSL	Emergency Power Switching Logic
EQ	Environmental Qualification
ES	Engineered Safeguards
ESF	Engineered Safety Feature
ESV	Essential Siphon Vacuum
ET	Eddy Current
f	Frequency
HELB	High Energy Line Break
HPI	High Pressure Injection
HSM	Horizontal Storage Module
ISI	Inservice Inspection
IFI	Inspector Followup Item
IP	Inspection Procedure
IR	Inspection Report
KHU	Keowee Hydro (electric) Plant

KV	Kilovolt
KVA	Kilowatt-Amperes
LCO	Limiting Condition for Operation
LDST	Letdown Storage Tank
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MFB	Main Feeder Bus
MOV	Motor Operated Valve
MTM	Minor Temporary Modification
MS	Main Steam
MU	Make-Up
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NSD	Nuclear System Directive
NSM	Nuclear Station Modification
OOS	Out of Service
OSM	Operations Shift Manager
OSW	Oconee Service Water
OTSG	Once Through Steam Generator
PCE	Personnel Contamination Event
PDR	Public Document Room
PF	Power Factor
PIP	Problem Investigation Process
PMT	Post Maintenance/Modification Testing
PRA	Probabilistic Risk Analysis
PSIG	Pounds Per Square Inch Gauge
PT	Penetrant Examine
QA	Quality Assurance
QC	Quality Control
RB	Reactor Building
RCA	Radiological Control Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
REV	Revision
RFO	Refueling Outage
RMSA	Radioactive Material Storage Area
RWP	Radiation Work Permit
RV	Reactor Vessel
SAM	Small Article Radiation Monitor
SER	Safety Evaluation Report
SFP	Spent Fuel Pool
SLC	Selected Licensee Commitments
SPDS	Safety Parameter Display System
SRO	Senior Reactor Operator

SYC	Synchronization Check
TEPR	Top Equipment Problems Resolution
TM	Temporary Modification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Test
VIO	Violation
V	Voltage
WCCSRO	Work Control Center Senior Reactor Operator
WO	Work Order
WPM	Work Process Manual