U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	Oconee Nuclear Station, Units 1, 2 & 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	June 15 - July 26, 1997
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Enclosure

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/97-10,
50-270/97-10, 50-287/97-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six week period of resident, regional, and headquarters project manager inspection effort.

Operations

- During two tests of the Lee Steam Station (LSS) Technical Specification (TS) required capability to provide backup power to the Oconee nuclear units, several problems occurred. Testing was performed using the shutdown Oconee Unit 1. During test one, a temporary loss of power occurred to Oconee Unit 1. During the loss of power event, Keowee Hydro Unit (KHU) 1 failed to develop a generator field due to a field flashing breaker control power failure. During test two, Air Circuit Breaker (ACB) 7 operated unexpectedly. The NRC sent an Augmented Inspection Team (AIT) to investigate these problems. Overall, Oconee personnel responded well to the problems, maintaining the units in operable status. There was one operational-related exception to this (involving testing of KHU 2), which was discussed in the AIT report. (Section O1.2)

- The licensee prepared and executed an off normal startup and power escalation with three Reactor Coolant Pump (RCP) operation in a professional and controlled manner. Procedure development and simulator training for this evaluation was excellent. Plant parameters and control circuits behaved as predicted. (Section O1.3)

- Licensee actions and reactor post trip response were acceptable to a July 6 Unit 2 Main Turbine Generator (MTG) and reactor trip which was due to a MTG voltage regulator automatic gain board adjustment problem. A weakness was identified concerning licensee control of voltage regulator setpoint adjustments. (Section O1.4)

- The licensee discovered and investigated a Unit 3 MTG seal oil problem, shutting down the unit upon the discovery of a potential for an explosive hydrogen/oxygen mixture in the MTG seal cavities. Although past procedure deficiencies and equipment problems had slowed the problem investigation, the licensee adequately corrected the problem and continued to investigate the root cause. (Section O1.5)

Maintenance

- Except as noted during troubleshooting on Air Circuit Breakers 5 and 7 (Section M1.6), observed maintenance work activities were completed thoroughly and professionally. (Section M1.1)

- Unit 1 Letdown Storage Tank (LDST) level modification work was considered acceptable for re-start. The actions were commensurate with the intent of NRC Confirmatory Action Letter Number 2-97-003. (Section M1.2)

- A weakness in the licensee's program used to implement process control for the replacement of Unit 3 HPI recirculation flow orifice assemblies, resulted in a failure to perform code required Non-Destructive Examination (NDE) before the unit returned to power. (Section M1.3)

- Replacement of Unit 1 High Pressure Injection (HPI) recirculation flow orifice assemblies 1A1 and 1B1 was performed following applicable code and procedural requirements. Installation, inspection and testing of these assemblies was done in a well-planned and controlled manner. (Section M1.3)

- The licensee satisfactorily replaced Unit 1 HPI mini-flow orifice assemblies and verified the integrity of Unit 1 HPI nozzles, safe-ends/piping and thermal sleeves. These actions were commensurate with the intent of NRC Confirmatory Action Letter Number 2-97-003. (Section M1.3)

- Volumetric (Ultrasonic/Radiographic) examination of welds associated with the Unit 1 HPI nozzles, safe ends, associated piping and thermal sleeves was performed in a conservative manner by well trained technicians following approved procedures. These procedures were shown to be capable of detecting the cracking condition observed in Unit 2. (Section M1.3)

- While observing relief valve repair and testing, the licensee and inspector observed weakness in the valves testing process. The licensee captured the minor problems in their corrective action program. (Section M1.4)

- The licensee generally maintained proper control over the troubleshooting and maintenance activities associated with the Unit 3 solenoid operated fast acting and servo valves on Main Turbine Control Valve Number 4. (Section M1.5)

- Troubleshooting activities following the June 23 Keowee Air Circuit Breaker (ACB) event were generally in an organized and controlled manner. However, on two occurrences, maintenance technicians did not perform troubleshooting activities according to management expectations and potentially delayed the root cause determination. Additionally, the licensee initially missed an opportunity to diagnose the reason that control power fuses blew in both ACB 5 and 7. (Section M1.6)

- Based on the observations, reviews and discussions, the inspectors concluded that the voltage regulator amplifiers contributed to the Unit 2 turbine trip and reactor trip on July 6. The lack of past (December 1996/January 1997) knowledge in adjusting the amplifiers was the cause of the generator not responding to a grid perturbation. Aside from some minor deficiencies, the recent work activities (calibration check and adjustment of the Unit 2 voltage regulator) were performed in accordance with approved procedures with engineering and supervisor oversight. (Section M2.1)

Engineering

- During this period, the licensee found and removed additional unqualified insulation material in all three reactor buildings. The past operability reviews of this issue will be resolved as a continuation of a previously identified unresolved item. (Section E1.1)
- The inspectors concluded that the Keowee Hydro Units' field flash breaker modifications were installed and tested in accordance with approved procedures and appropriate engineering and supervisory oversight. The modifications met the acceptance criteria during the post modification testing. Modification and testing activities were completed thoroughly and professionally. The overall activities were considered excellent. (Section E2.1)
- The process used at Oconee to perform safety evaluations was found to meet the requirements of 10 CFR 50.59. However, a Non-Cited Violation (NCV) was identified concerning a failure to accurately reflect modifications in the Annual Updated Final Safety Analysis Report Submittal. (Section E3.1)

Plant Support

- The inspectors found the emergency preparedness program to be maintained in a state of operational readiness and changes to the program to meet regulatory requirements. Program strengths noted by the inspector included the Emergency Preparedness training program and the number of personnel trained for Emergency Response Organization positions. (Section P1.1)
- During the July Emergency Planning Drill, communications between the simulated control room and the Technical Support Center (TSC) were not clear on several scenario issues. Inspectors discussed these deficiencies with the licensee. (Section P1.2)

Report Details

Summary of Plant Status

Unit 1 was shutdown on June 14 for a scheduled outage to inspect high pressure injection (HPI) lines/nozzles, as well as perform Letdown Storage Tank and HPI pump recirculation flow orifice modifications (Sections 01.3, M1.2, and M1.3). The unit resumed power operations July 3, operating on three reactor coolant pumps and remaining at approximately 70 percent power the rest of the inspection period.

On June 25, Unit 2 power was reduced to less than 20 percent for about one day to inspect and remove unqualified insulation from the unit's Reactor Building (Section E1.1). On July 6, the unit experienced a reactor/turbine trip from grid instability and main turbine generator voltage regulator adjustment problem (Section 01.4). Unit 2 was restarted the following day and remained at 100 percent power the rest of the inspection period.

Unit 3 reduced power to approximately 15 percent on June 24. The Main Turbine Generator (MTG) was taken off line for main generator seal oil system repairs (Section 01.5). Power operations resumed on July 5 and the unit remained at 100 percent power the rest of the inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

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

01.2 Unit 1 Electrical Test with Lee Steam Station (LSS)

a. Scope (71707)

On June 20 and 23, the licensee performed a Technical Specification (TS) 3.7.2 required test of the LSS to load onto the stand-by bus within one hour. The Senior Resident was present to observe the test. Unit 1 was in an outage and available for the test required conditions.

b. Observations and Findings

For the extensive Unit 1 electrical test of the LSS, a pre-evolution brief was conducted. The purpose of the test was to demonstrate the LSS's ability to provide power to a shutdown reactor unit in one hour. By the Oconee procedure, both the Duke load dispatcher and LSS were aware and prepared for the test. Operators and support personnel were knowledgeable about plant status, procedural requirements, and contingency plans.

During the June 20 performance of test PT/0/A/0610/006, 100 KV Power Supply from Lee Steam Station, Oconee Unit 1 incurred a loss of power. The test procedure performance had been completed to the point that the standby bus (breakers SL1 and SL2) was providing power to the unit via the LSS switchyard. The LSS fossil Turbine Generator (TG) 6C was to be made electrically synchronous to the yard and then connected to SL1 and SL2. Due to an apparent LSS operator error, the TG was connected to SL1 and SL2 before synchronizing. Due to the LSS being connected to the Oconee standby busses out-of-phase, SL1 and SL2 opened on under voltage. The Oconee Unit 1 main feeder bus monitor panel (MFBMP) sensed the loss of power, which provided an emergency start signal to the Keowee units. Because there was preferred power available in the 230 KV switchyard, Oconee Unit 1 transferred to the startup transformer regaining power in about 20 to 30 seconds.

The units were not challenged by the event. Units 2 and 3, which were at power, were not affected by the event. Unit 1 loads that were stripped off their busses during the loss of power, loaded back on the busses automatically or were quickly restarted by the operators.

During the Keowee Hydro Units (KHU) automatic sequencing, KHU 1 failed to develop a generator field and was unavailable at that point, while KHU 2 functioned properly and was available to the overhead path. A fuse for the field flash breaker (FFB) for KHU1 had blown causing the breaker not to close. The licensee initiated PIP 6-97-1906 and initiated a Failure Investigation Process (FIP) team evaluation on the FFB problem. Operations had appropriately entered into one TS Limiting Condition for Operations (LCO) for the out-of service KHU 1, but did not test KHU 2 per TS 3.7.2 within one hour as discussed in the AIT report mentioned below.

Per licensee evaluation, the KHU 1 was returned to an operable status within TS time limits, and on June 23 the LSS test was re-performed. During this test, the LSS provided power to SL1 and SL2 as required by the test's acceptance criteria. While realigning the plant electrical system to normal configuration during a dead bus transfer of KHU 1 auxiliary power, Air Circuit Breaker (ACB) 7 did not perform as expected (see Section M1.6). The licensee initiated a second PIP 0-97-1927 and a second FIP team to evaluated this breaker problem. Operations had appropriately entered into the TS LCO for the out-of service KHU 1. The

ACB 7 problem was preliminarily identified as a bad ACB timer problem. KHU1 was returned to service within TS 3.7.3 LCO time limits.

The NRC chartered an Augmented Inspection Team (AIT) to review the aforementioned problems. Inspection Report (IR) 50-269,270,287/97-011 discussed the details of the AIT findings. Future followup inspections of the above issues will be conducted once final licensee reviews of the events are concluded.

c. Conclusions

During two tests of the LSS, TS required capability to provide backup power to the Oconee nuclear units, several problems occurred. Testing was performed using the shutdown Oconee Unit 1. During test one, a temporary loss of power occurred to Oconee Unit 1. During the loss of power event, KHU1 failed to develop a generator field due to a FFB control power failure. During test two, ACB 7 operated unexpectedly. The NRC sent an AIT to investigate the problems. Overall, Oconee personnel responded well to the problems, maintaining the units in operable status. There was one operational-related exception to this (involving testing of KHU 2), which was discussed in the AIT report.

O1.3 Unit 1 Preparations for and Subsequent Restart Using Three Reactor Coolant Pumps (RCPs)

a. Scope of Inspection (71707)

After inspections of the Unit 1 HPI nozzles (see Section M1.7), installation of new Letdown Storage Tank (LDST) instrumentation, and replacement of the HPI mini-flow recirculation orifice assemblies (Section M1.2 and M1.3 respectively), Unit 1 was prepared for restart. As with the above maintenance work, the inspectors observed many of the operational restart activities. The inspectors attended the just-in-time training and pre-job briefings, as well as reviewed the startup procedure and operator logs, verifying that the unit and operators were prepared for the restart.

b. Observations and Findings

During a June 25 1A1 RCP start attempt at low Reactor Coolant System pressure and temperature, the pump vibrated at 46 mils vibration level at the shaft spool piece location. The pump was secured within 3 minutes when the licensee confirmed the actual higher than expected level. In the past, once normal operating pressure and temperature were attained, the 1A1 RCP would operate at lower vibration levels due to pump hydraulic stabilization. Previous pump problems were discussed in IR 50-269,270,287/97-02, Section O1.4. On June 28, the licensee restarted the 1A1 RCP while in Hot Shutdown conditions. This resulted in approximately 60 mils vibration at the shaft spool piece and the licensee again secured the pump. Due to the pump not performing as expected, the licensee made preparation to restart the unit with only three RCPs as allowed in their UFSAR and design basis. The licensee initiated PIP 1-97-1990 on specific vibration levels and documented an evaluation regarding operation under these conditions in PIP 1-97-2025. PIP 1-97-568 addressed the root cause of the pump vibration and the licensee's technical resolution. The inspectors found the licensee's rationale and evaluation acceptable.

On July 1, the inspectors attended training for the impending Unit 1 restart and MTG latching to the electrical grid. The training was conducted on the licensee's operator training simulator with recently prepared procedure OP/1/A/1102/01, Enclosure 4.3, Unit Startup from Hot Shutdown with Three (3) Reactor Coolant Pumps. For reactor criticality and power operations, the normal plant procedures were identified for use without any required changes. Using the existing procedure, the startup evolution was satisfactorily simulated with three RCP operation. Further, the conducted training critiqued the new procedure details with the Operation's crews providing feedback. As a result of the training, only minor changes to the Enclosure 4.3 procedure were required. The training was well focused and operator attention to detail was excellent.

On July 3, Unit 1 startup activity was controlled by Operations Procedure OP/1/A/1102/01, Controlling Procedure for Unit Startup. As required by OP/1/A/1102/01, the licensee conducted a pre-job briefing for the reactor startup. The pre-job briefing included reviewing past industry events that occurred during startups. The inspector reviewed the Estimated Critical Boron and Estimated Critical Position calculations. On July 3, 1997, at 4:56 a.m., the unit achieved criticality. Operations performed the startup to criticality in a slow and deliberate manner with no problems or concerns noted.

Later on July 3, the licensee proceeded from approximately 15 percent power to latching the MTG to the grid. The pre-job brief and Operation's personnel preparation for the evolution were excellent. Operator attention and management oversight were evident as the evolution progressed. Only one problem occurred during the evolution, which involved the 1B main feedwater block valve (1FDW-40). The block valve did not open with the control switch being in automatic when the 1B startup control valve (1FDW-44) reached 90 percent open as designed (PIP 1-97-2043). This was just prior to critical steps in the evolution. The operators identified the problem early and were well supported by Instrument and Electrical (I&E) personnel who were in the control room (CR) in a support capacity. The evolution was halted to investigate the valve problem. The plant was kept in a stable condition while certain operational and technical checks were made. A Motor Operated Valve (MOV) engineer was called to provide technical support. The licensee addressed a possibility that the valve had thermally bound during the last unit shutdown. The valve was not required for accident mitigation nor was it required to be addressed under the licensee's

Generic Letter (GL) 89-10 MOV program. Several electrical attempts to operate the valve indicated that the valve was stuck in its seat beyond the available breaker thermal load protection power delivery capability. The operators manually unseated the valve without using excessive force. Subsequent stroking of the valve indicated that it was performing as required; however, further engineering evaluations to address the issue will be performed via the licensee's is PIP proram.

After 1FDW-40 was found to be acceptable and placed in its correct position, the licensee re-briefed the control room personnel and re-focused the operators prior to proceeding with the most critical steps of the procedure. Due to the loss of the 1A1 RCP on the 1A Reactor Coolant System (RCS) loop and the attendant 1A loop reduction in flow and thermal capability, the feedwater to the 1A Once Through Steam Generator (OTSG) would have to be controlled at a lower flow rate than normal. This resulted in an A to B loop flow offset instead of being balanced. Previous experience at Oconee and at other Babcock-Wilcox facilities that had been researched by the licensee, indicated that the automatic feedwater proportioning circuits would not be stable until approximately 20 to 30 percent power. Once stability was reached, the proportioning circuits could be placed into automatic operation. Simulator trial and error practice had been incorporated into a viable Enclosure 4.3 instruction. During the above mentioned pre-evolution training, Operations and Training personnel, who had developed the procedure based on trial and error and operating experience, stressed the importance of slowly increasing feed to the 1B OTSG initially until the 1A OSTG level responded to the increased reactor thermal output. At the time of MTG latching to the grid, 1A and 1B feedwater masters and Delta T (temperature) Cold Controllers were in manual control and the remainder of the Integrated Control System (ICS) was in automatic control. During the increase in power under the procedure guidance, the operators followed their training, taking the time to keep the plant stable. Power escalation was stable and smooth throughout the observation period. When placed into full automatic control, the ICS control valves did not change position.

Reactor engineering assisted in the power escalation. They were concerned that a flux tilt would possibly occur requiring additional minor plant maneuvers. They observed computer provided flux tilt values continuously and observed other non-automated instruments during the power increase. Due to the slowness of the power increase, no operational concerns developed.

c. <u>Conclusions</u>

The licensee prepared and executed the off normal startup and power escalation with three RCPs operating in a professional and controlled manner. Procedure development and simulator training for this evolution was excellent. Plant parameters and control circuits behaved as predicted.

01.4 Unit 2 Trip with Grid Instability

a. Scope (93702)

On Sunday July 6, 1997, an event at the Jocassee Hydro-electric Station initiated an Oconee Unit 2 trip. The investigation revealed several problems at Jocassee and a problem with the Oconee Unit 2 voltage regulator adjustment settings. The senior resident was called at approximately 7:20 a.m. and immediately responded.

b. Observations and Findings

On July 6, Unit 1 was near its maximum power level for three RCP operation (approximately 70 percent), Unit 2 was at 100 percent power, and Unit 3 was at approximately 90 percent power. Unit 1 had reached this plateau on July 3. Unit 2 had been at power since May 24. Unit 3 had gone on line at 12:09 p.m. July 5. Unit 1 was operating with 78 MVAR (megavolt-amps-reactive). Unit 2, which shares a common 230 KV switchyard with Unit 1, was operating with about 50 MVAR. Unit 3 was on a separate 525 KV switchyard with 114 MVAR.

The Duke-Jocassee units are four, 160 megawatts (MW) (each), hydro-electric units located approximately 11 miles from the Oconee Nuclear Station. The Jocassee units were in lift mode, pumping water from Lake Keowee to Lake Jocassee. Jocassee's connecting electrical lines enter the Oconee 230 KV yard on the Unit 1 side of the switchyard. At approximately 6:52 a.m., Jocassee was switching auxiliary loads when Jocassee Units 1 and 3 lost motor excitation. Since the motors did not trip, the local grid load rapidly increased when the Jocassee motors became large inductive loads. Subsequently, Oconee Unit 2 tripped within seconds of the Jocassee units' change in state. The Oconee Unit 2 auxiliaries transferred to the unit startup transformer as expected with no needed actuation of the KHUs.

With few exceptions, Unit 2 responded normally to the trip from 100 percent power. Operators entered appropriate emergency post trip procedures. Immediately following the trip, the unit was in normal hot shutdown conditions and Duke personnel were investigating the event. Due to the trip, RCS volume shrinkage caused pressurizer level to drop to approximately 60 inches (normal level is 221 inches). The 2A HPI pump had been in operation. Due to low RCP seal injection flow, the 2B HPI pump auto-started. Operators manually started the 2C HPI pump to limit pressurizer shrinkage. Pressures in the main steam lines respectively reached 1135 and 1143 psig, with reliefs lifting and fully reseating. In addition, the 2A condensate booster pump seal developed a leak. The licensee submitted a timely 4 hour report to the NRC regarding the reactor trip.

Aside from some minor alarms, Oconee Units 1 and 3 remained in operation. Several minor alarms came in regarding overlapping circuits between the units, such as the Control Rod Drive Mechanism (CRDM) backup power. According to the Unit 1 computer, Unit 1 MVARs reached a value of 525 (alarm is 500). No known equivalent alarm came in on Unit 2 or Unit 3.

The licensee and inspector reviewed the available alarm summaries. The Unit 2 reactor trip was due to RCP power-to-reactor flux bistable actuation. A 6900 Volt bus voltage decrease apparently caused this trip. The inspector looked at the RCP busses and their breakers, no exposed relay targets were identified. The MTG was concurrently tripped with the reactor due to a three phase over current trip of the MTG 51VR relays. These relays actuated to cause a MTG lock out and opened yard Power Circuit Breakers. An approximate 100 MW swing was observed on the Unit 1 MW computer trend chart.

Shortly after the trip, licensee management and technical support were called out on the trip. Good investigative support was observed. The licensee's post-investigation meeting results indicated:

- that Jocassee auxiliary transfer action resulted in a loss of field excitation to the Jocassee turbine generator/pumps units. The two units which had been operating as motors attempted to re-establish their fields as an under-excited out-of-synchronous motor drawing excessive current;

- that over current protection at Jocassee did not operate to prevent over current protection initiation at Oconee Unit 2; and,

- that Jocassee over current protection operated following the trip of Unit 2 (within 300 milliseconds of Unit 2 protection operation) ending the transient.

A result of the above meeting was clear direction on the determination of breaker relay co-ordination between Oconee and Jocassee. During the night of July 6-7, Duke determined that protective relays at both Jocassee and Unit 2 Oconee were set in accordance with their set point documents. Additionally, to reduce the potential for further unexpected grid interactions, Duke management established a working agreement between Jocassee and Oconee that limited Jocassee operation until the interaction could be understood. Under the agreement, Jocassee would not pump or generate during auxiliary switching operations, Jocassee operators would notify the Oconee Operations Shift Manager prior to start of any switching operations, and Jocassee units would be shutdown prior to energizing the 100 KV Jocassee line to Oconee after an on-going Jocassee modification was complete. This agreement would exist until the root cause for the loss of excitation was clearly understood.

By the morning of July 7, the licensee had determined that the automatic control boards of the Units 1 and 2 MTG voltage regulator had been replaced due to potentiometer degradation on the automatic board. These boards had been adjusted during the recent forced outages (December/January respectively, Unit 3 was not done). These adjustments were made using verbal guidance provided by an offsite MTG vendor representative. The guidance consisted of adjusting two series gain potentiometers of the amplifier circuit on the automatic board to resistance values determined from the removed, existing board. This board setup was not described in the technical manual for the MTG control system; the manual did not clearly detail an automatic board setup. Expected MTG response to high current demand is discussed below.

Between the time of the setup of the new Oconee control boards and the present event, Duke technicians who maintain the MTG and Hydro-electric controls for the Duke system discovered a more accurate means of calibrating the automatic board of the voltage regulators. Within the Duke system, there are two fossil and two additional nuclear MTG control systems (Catawba) that have the same regulators as Oconee. The technicians had discovered a different MTG vendor representative that had been servicing the fossil MTG control systems. His verbally relayed method required the gains on the automatic board be set to a specific final output value (16:1). The technicians were to use this method during their next expected window of opportunity on the Oconee units in 1998.

Unit 2 was restarted the night of July 6 in preparation for re-initiation of MTG operation but was held at low power until the MTG problems were resolved.

During the morning of July 7, the licensee checked the gains on the installed automatic control board of the voltage regulator. Utilizing the latest calibration technique, the amplifier was found to be setup incorrectly. Specifically, the Unit 2 amplifier on the automatic board was saturated. It would not and did not control power as required, in that the voltage regulator would not maintain a steady MTG bus voltage during overcurrent conditions. Its gain output was found to be about 28:1 versus 16:1. Re-adjusting the same board that had been replaced in the forced outage resulted in a stable calibration of the board and the amplifier operated as expected when post adjustment tests were performed (see Section M2.1). Power production was subsequently resumed late on July 7.

When properly calibrated, the voltage regulator in automatic mode of operation should limit the response of the MTG in transient situations. The MTG control circuitry should allow a limited response to an unbounded grid demand (i.e., beyond the current limiting MTG protection 51VR relay set points). The voltage regulator should be adjusted or coordinated to produce less power than those set point values. In the case of Units 1 and 3, the voltage regulators responded as required to prevent excessive electrical reactive power production.

Post event review of Jocassee activities and equipment condition revealed causes for the loss of excitation for Jocassee Hydro Units 1 and 3. Unit 1's loss was due to an A.C. invertor that was inadvertently taken to the "off" position. Unit 3's loss was attributed to a defective blocking diode on the motor/generator's speed switch sensing coils that caused the speed switch relay to drop out. These were corrected upon identification.

At the end of the inspection, the licensee: was still studying grid interactions and future voltage regulator adjustments; had informed the Catawba Station of the Oconee voltage regulator problem; was discussing automatic board setup with the MTG vendor; and had issued general event information to the nuclear industry. Further, the licensee planned to issue more specific information on the details of the event when it became available. The inspectors had discussed the details of the problems with the Region, Headquarters, and the residents at the Catawba site.

c. Conclusions

Licensee actions and reactor post trip response were acceptable to a July 6 Unit 2 Main Turbine Generator (MTG) and reactor trip which was due to a MTG voltage regulator automatic gain board adjustment problem. A weakness was identified concerning licensee control of voltage regulator setpoint adjustments.

The subject voltage regulator is non-safety-related but the control system is under the regulatory umbrella of the NRC Maintenance Rule, 10 CFR 50.65. Accordingly, the licensee will make adjustments to their tracking systems for this failure accountability as required under that rule.

O1.5 Unit 3 Down Power Due to Seal Oil Problems

a. Scope (92901)

The inspectors followed the licensee's activities regarding MTG generator hydrogen seal oil problems. These problems persisted over most of the inspection period and the inspectors discussed and observed the licensee's efforts to resolve the problems. The problem appeared to be unique to Unit 3.

b. Findings and Observations

On June 24, due to MTG seal oil problems, Unit 3 was reduced from 100 to approximately 15 percent power with the MTG being taken off line. During the recent May 26 return to power operations, the seal oil tank level had trended to a lower than normal level with the emergency backup oil pump on the seal oil skid being put into service to maintain seal oil tank level. MTG vendor assistance had been requested through the general office. Via a parallel path, engineering discovered from the MTG vendor that the running of the emergency backup pump may not scavenge oxygen as efficiently as running with the normal pump alone; thereby possibly building up an explosive mixture of hydrogen and oxygen in the MTG seal cavities. Upon learning this information, the licensee conservatively shut down the MTG for investigation of the seal oil level problems. PIP 3-97-1988 was generated and the MTG vendor was re-contacted for additional support.

Initially, the seal oil system problem was thought to be primarily that the 3-SO-12 and 3-SO-55 valves (seal oil flow control valve and the tank level control valve, respectively) were not setup properly. Particularly, the SO-55 valve had parts provided by a vendor (Fisher Controls) and the MTG vendor or Duke personnel installed them to suit the tank configuration of the seal oil skid. Required repair instructions were not addressed in the skid technical manual. The technical manual drawing for the float valve indicated the wrong fulcrum position for the actuation arm. The necessary particulars of the Fisher parts' adjustments were not proceduralized by the licensee. The licensee had not captured these details in any local instructions due to normal utilization of seal oil skid and MTG vendor representative for work control. Specifically, the SO-55 valve is a float valve in the tank requiring positioning of the arm at the appropriate fulcrum arm length for the specific application. The existing SO-55 valve was found with the arm length mis-adjusted such that the level was not controlling in a band that had been coordinated with flow control valve SO-12. Observation of Units' 1 and 3 seal oil skids indicated that these particular devices were controlling appropriately.

The licensee's continued examination of the problem revealed another more critical problem with the seal oil system. The licensee's investigative team observed a higher than expected seal oil flow rate. The licensee disassembled the seals to determine the cause of the high flow rate. The seal at the collector end of the generator had been worn to an approximate 0.020 inch gap, while normal gap between the seal and shaft is approximately 0.0035 inch. With the worn seal, the seal oil system operated at a higher than normal flow rate that was greater than the makeup to seal oil tank. The seal was replaced and the other MTG seals were checked.

On July 5, once the above problems were corrected, power operation resumed with the seal oil tank level in a controllable and stable condition. The licensee continued their investigation and corrective action beyond the end of the inspection period.

c. Conclusions

The licensee discovered and investigated a Unit 3 MTG seal oil problem, shutting down the unit upon the discovery of a potential for an explosive hydrogen/oxygen mixture in the MTG seal cavities. Although past procedure deficiencies and equipment problems had slowed the problem investigation, the licensee adequately corrected the problem and continued to investigate the root cause.

O2 Operational Status of Facilities and Equipment

O2.1 Engineering Safety Feature and General Plant Walkdown (71707)

The inspectors used Inspection Procedure 71707 to walkdown accessible portions of the following safety-related systems:

- Keowee Hydro Station
- Unit 1, 2 and 3 Penetration Rooms
- Standby Shutdown Facility (SSF) - Emergency Diesel Generator (EDG)
- Unit 1 Emergency Feedwater
- Intake Structure
- 230 KV Switchyard
- Lee Steam Station

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected.

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 97-052374-01 Keowee Field Flash
- PT/1/A/0203/006A Low Pressure Injection Pump Test - Recirculation After Maintenance
- PT/1/A/0600/013 Emergency Feedwater Test
- PT/1/A/610/06 Lee Power Test

- WO 97-029491-02 — Check Calibration of Unit 2 Main Generator Voltage Regulator
- PT/0/A/2200/009 — Auxiliary Power Transfer Surveillance ACB 6 and ACB 8 (June 26 performance)
- PT 0/A/2000/12 — Restoration of ACB Number 8
- WO 97054608-01 — Field Flash Breaker Auxiliary Contact Overlap Check
- WO 97056684-01 — U-3 Control Valve Number 4 is Cycling
- WO 97053178-01 — Inspect/Repair (I/R) Blown Control PWR Fuse - Keowee ACB-7
- WO 97053179-01 — I/R Blown Control PWR Fuse - Keowee ACB-5

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 active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress. Quality control personnel were present when required by procedure. When applicable, appropriate radiation control measures were in place.

c. Conclusion

Except as noted in Section M1.6 (troubleshooting ACB-5 and 7), the Maintenance activities listed above were completed thoroughly and professionally.

M1.2 Unit 1 LDST Modifications

a. Scope of Inspection (62707)

During this period, the inspectors inspected the LDST level modification installed prior to Unit 1 startup.

b. Observations and Findings

The inspector observed the final installation of the Unit 1 LDST level modifications (inside and outside the tank cubicle), including the calibrations of the units' non-safety-related level transmitters and filling of the reference legs. The installation, closeout paper work, and associated pressure testing were found to be satisfactory.

c. Conclusions

The inspectors found the Unit 1 LDST level modification work acceptable for restart. The actions were commensurate with the intent of NRC Confirmatory Action Letter Number 2-97-003 (Section O1.4 of IR 50-269,270, 287/97-05).

M1.3 Inspections of Safety-Related Welding and Non-Destructive Examinations (NDE) (62700, 55050)

a. Inspection Scope

This inspection was performed to determine (by work observation, interviews and document review) the adequacy of the licensee's process control, welding practices, inspection and testing of the subject welds, piping and thermal sleeves. The applicable codes included ASME Sections XI, 1989 Edition and ANSI B31.7, 1969 Edition.

b. Observations and Findings

Installation of Unit 1 Minimum Recirculation Flow Orifice:

Degradation of the HPI minimum recirculation flow orifice assemblies in Units 2 and 3 prompted the licensee to check the condition of those in Unit 1 and to take appropriate corrective action as needed. As discussed in Inspection Report 50-269, 270, 287/97-05, the Unit 1 orifice assemblies had been declared "degraded but operable" with the licensee performing weekly X-ray checks of the assemblies to verify integrity until Unit 1 was shut down on June 14. At the time of this inspection, the licensee had made the decision to replace the 1A1 and 1B1 orifice assemblies (four total). The replacement work effort was being conducted under Work Order (WO) numbers 97045591 and 97045594, respectively. The inspectors reviewed material certification for the replacement orifice assemblies, associated piping and filler metal used. In addition, the inspectors reviewed applicable weld process control sheets to verify completeness, accuracy and compliance with applicable code requirements. Following installation, the inspectors inspected the completed welds to verify that code requirements had been met and good workmanship practices had been followed. The new welds were identified on weld Isometrics 1HP-272, Rev. 1 and 1HP-273, Rev. 2 respectively. Visual examination and liquid penetrant tests (PT) showed all associated welds met minimum code requirements. Code Case N-416-1, Alternative Pressure Test Requirements for Welded Repairs or Installation of Replacement Items by Welding, was invoked as an alternative to the code required hydrostatic testing. Personnel qualification records for welders and NDE examiners were checked and found to be in order.

Installation of Unit 3 HPI Minimum Recirculation Flow Orifice

Prior to this inspection, Unit 3 had been shutdown to examine the integrity of certain welds associated with the HPI nozzles in response to a Unit 2 pipe weld failure in this system. Weld No. 3-HPI-262-45 on the subject orifice assembly is a circumferential butt weld on the outer orifice of the assembly. This weld was created as a result of the licensee's effort to repair existing orifice assemblies. After making the weld in the fabrication shop, NDE determined that orifice configuration precluded full coverage of the weld by x-ray/radiography. Engineering instructed NDE personnel to radiograph (RT) the weld on a best effort basis. As predicted, radiography provided only limited weld coverage. Without further evaluation and supplementary nondestructive examinations to assure weld integrity, the plant returned to power. For further details, see IR 50-269,270,287/97-05. Through discussion with cognizant licensee personnel, and document review, the inspectors ascertained the following information. Failure to achieve full weld coverage by radiography was noted on June 3, 1997, by the Authorized Nuclear Inspector (ANI) when the unit was at approximately 90 percent power.

The inspector determined that the responsible engineer failed to provide written instructions, to Process Control and/or to Quality Control (QC)/NDE, describing alternative NDE methods to be used in the event radiography failed to provide full weld coverage. All communications between the responsible engineer and QC were informal/verbal. Consequently, there was no objective evidence showing that engineering intended the subject x-rays for information or code acceptability. Also, there was no written instructions to NDE personnel requesting them to contact engineering with x-ray examination results and receive further instructions. When the licensee determined that full compliance with the applicable code had not been achieved, the following corrective actions were taken: (1) the subject weld was examined with an ultrasonic examination (UT) procedure especially written for the existing weld conditions; (2) a request for relief from applicable code requirements was submitted to NRC (the submittal requested permission to use UT as an alternative to radiography which proved impractical in the application); (3) a root cause analysis was conducted to gain a better understanding of the lack of communications and apparent breakdown in process control. Failure to assure that replacement welds are fabricated and examined in full compliance with applicable code requirements was identified as a violation in Inspection Report (IR) 50-269,270,287/97-05.

Within these areas, the inspectors reviewed the film and UT records of the subject weld (3-HPI-262-45). Also, the inspector evaluated examination results and discussed the UT technique used with the Level II Quality Control Examiner. Through this work effort, the inspectors ascertained that even though the procedure had been approved by the Level III, UT Examiner for use on this application, the procedure had not been demonstrated to the ANI before it was used. Demonstration of new NDE procedures to the ANI inspector is required by the applicable code. In response to this observation, the ANI inspector was provided with a copy of the procedure for review. A subsequent demonstration of this procedure found it acceptable for the application.

In discussing this problem with the licensee, the inspectors noted that even though the adequacy of the procedure or the UT examination performed were not in question, it demonstrated weakness in addressing programmatic requirements and attention to detail.

Volumetric Examination of Unit 1HPI Nozzles, Associated Components and Welds

Volumetric examinations were performed on Units 2 and 3 HPI nozzle welds, thermal sleeves and associated pipe welds to assess the extent of cracking caused by high cycle thermal fatigue that was observed in Unit 2. (See IR 50-269,270,287/97-07, for more details.) Licensee Event Report (LER) No. 50-270/97-01, dated May 21, 1997, Unisolable Reactor Coolant Leak Due to Inadequate Surveillance Program, described the corrective actions to be performed. These actions included component replacement, failure analysis, enhancements to the surveillance program, and training. The latter was intended to raise personnel sensitivity towards abnormal conditions observed during plant operation and while performing NDE on the subject components. Also the inspectors noted that the aforementioned LER, included several (seven) commitments. These commitments included shutting down Unit 1 on/or before June 14, 1997, to perform RT and UT examinations on the HPI nozzle components. As such, the inspector observed liquid penetrant and UT examinations performed on 1A1 and 1A2 HPI nozzle welds and associated components. The liquid penetrant examination showed no evidence of code rejectable surface indications. The ultrasonic examination identified several (four) innocuous indications in the following welds:

Weld	Weld Description	Indication
1A2-IRC-200-86	Valve to Pipe	Geometric reflector associated with valve I.D. configuration
1A1 Inner Radius	Nozzle Inner	Three indications, all Nozzle Radius geometric reflectors... One from the inside radius of the nozzle and two from the clad to base metal interface
1A2 Inner Radius of Nozzle	Nozzle Inner Radius	Four indications, all geometric reflectors...One from the inside radius of the nozzle and three from the clad to base metal interface

The above indications were investigated, plotted and evaluated by two Level III UT Examiners who determined that the indications were not cracks, but rather geometric reflectors. These indications will be monitored under the licensee's augmented inspection plan outlined in LER 50-270/97-01.

Radiography of HPI Thermal Sleeves, Unit 1

Thermal sleeves for Unit 1 HPI nozzles 1A1, 1A2, 1B1, and 1B2 were radiographed between June 16-17, 1997, per procedure NDE-105, Rev. 0. The thermal sleeves and associated welds between the respective nozzles and piping were shot while water was in the lines/pipes. In general, the inspectors found the radiographic technique produced acceptable results. Areas of interest including hard roll sections and gaps between the thermal sleeve and nozzle safe-end in the expansion area of the thermal sleeve, exhibited good radiographic and film quality. Radiographs shot during the present outage were compared with those taken in July 1983. This review found no evidence of thermal sleeve movement. Weld integrity appeared satisfactory, the thermal sleeves appeared to be in good condition and the bond between the inner and outer sleeve was being maintained. The thermal sleeve in Nozzle 1B2 showed a gap length of about 0.875" on the nozzle side of the expansion area. This gap length was slightly longer than the 0.8125" observed in 1983. However, the Level III evaluated this change in length as being symptomatic to the radiographic technique used rather than physical movement by the thermal sleeve.

c. Conclusion

Welding and NDE activities observed followed applicable code requirements. Procedures controlling these activities were capable of achieving desirable results of crack detection. Problems continued to surface, however, as a result of inadequate communications and engineering's inability to provide adequate leadership and a strong active roll in job execution when such action was required.

The licensee satisfactorily replaced Unit 1 HPI mini-flow orifice assemblies and verified the integrity of Unit 1 HPI nozzles, safe-ends/piping and thermal sleeves. The actions were commensurate with the intent of NRC Confirmatory Action Letter Number 2-97-003 (Section 01.4 of Inspection Report 50-269,270,287/97-05), with no other weekly compensatory actions required.

M1.4 Repairs to Low Pressure Injection System Relief Valve (Unit 2)

a. Inspection Scope (62707)

The licensee identified a leak on Low Pressure Injection (LPI) relief valve 2LP-27. The valve is located on the suction side of LPI pump 2B.

b. Observations and Findings

The leak was identified in the outlet portion of the 3/4 inch relief valve located on the 14 inch suction piping to the 2B LPI pump. The outlet portion of the valve. The outlet of the valve is normally not under pressure. During normal system operation, the outlet of the valve is vented to a tank which is normally at low pressure. The tank is equipped with a rupture disc and is not vented to the atmosphere. During filling and venting of the LPI system, the pressure in the outlet side of the valve went as high as 42 psig. This was due to the system configuration with a common relief valve and system venting discharge path to the tank.

The inspectors observed activities and reviewed documents associated with the repair. The inspectors reviewed valve procedure SM/0/A/8030/011, Anderson Greenwood Model 81P Relief Valve Testing and Corrective Maintenance, Rev 2, and associated WO 97-032611-01.

The inspectors observed the following:

- The procedure provided instructions for testing, disassembly, inspection, and reassembly of the model 81P valves.
- Section 3.3 provided for the as-found set pressure testing, Section 3.7 provided for as left set pressure testing, and Section 3.9 provided for back pressure testing, if required.
- Sub-section 3.9.3 directed that a verification of no visible leakage from the spring bonnet be performed.
- Enclosure 4.3, Relief Valve Test Data Sheet, provided data for specific valves.
- The WO directed the valve removal, disassembly and repair, and reassembly and testing.

During discussions with licensee personnel it was noted that the valve was not subjected to a back pressure test. Based on the Enclosure 4.3 data sheet that was with the work package, a back pressure test was not originally performed. The inspectors also discussed back pressure testing of the relief valves on LPI pump 2A and in the other units.

Post valve repair, the inspectors reviewed the completed WO and observed that the valve had been given a back pressure test in accordance with the Model 81P relief valve testing procedure. The cause of the leak was a twisted and pinched "O" ring in the bushing seal.

The inspectors concluded that the procedure contained two weaknesses. The first weakness concerned the back pressure test in Section 3.9, which states: "Back Pressure Testing, If Required." The procedure does not indicate how the "if required" is to be determined and who or which group has the responsibility for making the determination. The second weakness, identified by licensee personnel, concerned valve leakage during back pressure testing. Sub-section 3.9.2, of Section 3.9, states: "Verify there is no visible leakage from the spring bonnet." The failed "O" ring was in the bushing seal, which was located on the valve housing opposite the spring bonnet. The procedure also did not mention leakage from the valve plug, which also contains an "O" ring seal. The inspectors further concluded that had the valve actually lifted, the "O" ring seal in the bushing would have leaked, resulting in a possible radiological concern, but not an operational concern. The inspectors discussed these items with licensee maintenance, engineering and radiological control personnel. The licensee initiated PIPs 0-097-2231 and 0-097-2318 on the relief valve and related procedure problems.

c. Conclusions

While observing relief valve repair and testing, the licensee and inspector observed weaknesses in the valve testing process. The licensee captured the minor problems in their corrective action program.

M1.5 Unit 3 Main Turbine Solenoid Operated Fast Acting Valve

a. Inspection Scope (62707)

The inspectors observed portions of the servo valve replacement on Unit 3 Main Turbine Control Valve Number 4 and other work associated with its fast acting valve.

b. Observations and Findings

On July 6, 1997, the licensee reduced Unit 3 power level due to oscillations in Main Turbine Control Valve Number 4. The licensee determined these oscillations were caused by a faulty servo valve on the main control valve and replaced the servo on July 7, 1997. During the replacement, maintenance personnel manually energized the solenoid operated, fast acting valve (which performed servo hydraulic supply and main control valve trip functions) using a tool specifically designed to allow servo replacement online; however, the fast acting valve remained stuck in the energized position when the tool was removed. The licensee was later able to successfully troubleshoot and free the stuck fast acting valve and return the main control valve to service.

The inspectors observed the troubleshooting activities on the fast acting valve and determined the licensee maintained proper control over these activities. The inspectors noted the licensee modified the tool used to manually energize the fast acting valve without contacting the vendor (General Electric); however, the licensee later contacted the vendor and determined the changes made to the tool had no effect on the stuck fast acting valve. The licensee planed to replace the fast acting valve at the next outage.

After the above repairs, the inspectors observed elevated vibration of the electro-hydraulic supply lines in the vicinity of the main control valve after the servo replacement. This was pointed out to the licensee and the servo valve was adjusted dampening but not eliminating the vibration. The licensee was considering modification of the support hangers on the Unit 3 turbine valve hydraulic lines at the end of the period. These lines were hangered differently than those of the other units.

c. Conclusions

The licensee generally maintained proper control over the troubleshooting and maintenance activities associated with the Unit 3 solenoid operated fast acting and servo valves on Main Turbine Control Valve Number 4.

M1.6 Keowee Air Circuit Breaker (ACB) Troubleshooting

a. Inspection Scope (62707)

The inspectors observed the troubleshooting activities associated with the failure of Keowee ACB-5 and 7 to function properly during testing of the Lee 100KV power supply line. These activities were part of the events on June 20 and 23, 1997, involving the Keowee Hydro Station. These events were inspected in more detail by an Augmented Inspection Team. The results of that inspection have been documented in IR 50-269,50-270,50-287/97-11.

b. Observations and Findings

During recovery from testing of the Lee 100KV power supply on June 23, 1997, ACBs-5 and 7 failed to operate properly when Oconee 4160V Bus 1TC was transferred from the standby bus to the main feeder bus. This action involved a dead bus transfer and caused an expected loss of power to Keowee Auxiliary Bus 1X, because Bus 1X was supplied power from Bus 1TC via ACB-7. ACB-7 tripped as expected following the loss of voltage; however, it failed to reclose and caused a lockout of Bus 1X. ACB-5 did not close and provide power to Bus 1X due to the lockout. These actions left Keowee Unit 1 without auxiliary power. After verifying that no fault existed, operators reset the lockout; however, Bus 1X did not re-energize. Subsequently, the licensee found blown fuses in the control circuits for each ACB. The licensee formed a FIP team to investigate this event.

Technicians performing the troubleshooting determined on June 24, 1997, that ACB-7 'Y' coil time delay was out of specification and could not be adjusted. They initially decided this was not the cause of the event, replaced the timer, and continued troubleshooting without quarantining the part. The same day technicians discovered a loose wire on the 'X' coil for ACB-7, similarly decided it was not a factor in the event, tightened the wire, and continued troubleshooting again without a quarantine. The inspectors reviewed Nuclear System Directive 212, Cause Analysis, Revision 4, and questioned licensee management about these practices. Both the directive and management indicated that a quarantine of defective parts was expected in order to preserve evidence. The directive did not specifically require quarantine, using "should" and "could" statements in an engineering guidance sense. The licensee later determined the 'Y' coil on ACB-7 did indeed cause the loss of power event.

On June 25, 1997, the inspectors observed the FIP team discuss the possible root cause of the loss of power event. During this discussion several members of the team put forth ideas on how a control power fuse could blow in either ACB-5 or 7. They proposed that if the breaker received a close and a trip signal simultaneously, the breaker would trip (trip free) but the close coil would remain energized. The coil would then draw more amperes than the fuse rating and the fuse would blow. The team initially concluded this did not happen because close and trip signals were not present simultaneously. The inspector determined this approach to be incorrect and indicated to FIP team members that both breakers closed and tripped so quickly after lockout reset, that a trip free condition did indeed exist. The team members agreed with the inspector's determination.

c. Conclusions

The licensee generally conducted troubleshooting activities following the Keowee ACB event in an organized and controlled manner. However, on two occurrences, maintenance technicians did not perform troubleshooting activities according to management expectations and potentially delayed the root cause determination. Additionally, the licensee initially missed an early opportunity to diagnose the reason that control power fuses blew in both ACB-5 and 7.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Adjustment of Generator Voltage Regulator (Unit 2)

a. Inspection Scope (62707, 92902)

The inspectors reviewed and observed the calibration check and adjustment of the voltage regulator on the Unit 2 main generator. The calibration check and adjustment was performed as a result of a unit trip on July 6.

b. Observations and Findings

The observed activities were controlled by the following procedures and documents:

- Procedure IP/O/A/0100/01, Controlling Procedure for Trouble Shooting and Corrective Maintenance, Revision 11
- Procedure OM-2200-0070, General Electric Turbine Generator Instruction Book, Generator Section
- System Clearance OPS-97-2274-1
- Vendor Manual GEK 14870B, Alterex Excitation System Static Control
- Work Order 97029491, Check Calibration of Unit 2 Voltage Regulator

The section of the voltage control network that was checked was the auto-regulator circuit board which contained a first stage amplifier and a second stage amplifier. The work instruction directed the personnel to check the gain for both amplifiers. The as-found condition indicated that the gain of the first stage amplifier was 13 to 1, and the second stage, 2.2 to 1. This resulted in an overall gain of approximately 28 to 1.

The inspectors were informed that the gain for the first stage should have been 2 to 1 and the gain on the second stage should have been 8 to 1. The two amplifiers were adjusted to the acceptable gains. The inspectors were also informed that the "as-found" gains on the amplifiers caused the voltage regulator, on July 6, not to respond properly and to trip the main generator off the grid. The trip occurred when the generator began absorbing higher than normal MVAR. The high MVARs resulted in high generator output amps which, in turn, caused the generator to trip on high current.

The inspectors were also informed that there were two previous failures of the voltage regulator card. As a result of one of the failures the various potentiometers in the network were changed out and replaced with new during a refurbishment of a card. The card, with the new potentiometers, was installed in the Unit 2 Alterex. Due to a lack of experience with the Alterex by onsite personnel and information from offsite corporate personnel, the new potentiometers were adjusted to the same ohmic values of the replaced potentiometers. The adjustments may have contributed to the as found gain condition of the amplifiers. The inspectors noted two minor licensee-identified deficiencies, one involving the clearance and the other involving the adjustment of the gain on the first stage amplifier. Both deficiencies were immediately addressed. The inspectors discussed the deficiencies with licensee personnel.

During followup discussions with licensee personnel, the inspectors were informed that the Unit 1 Alterex amplifiers were scheduled to be checked during the fall 1997 refueling outage. Review of the Unit 3 Alterex amplifiers were still being discussed at the end of the inspection period.

c. Conclusions

Based on the observations, reviews and discussions, the inspectors concluded that the voltage regulator amplifiers contributed to the Unit 2 turbine trip and reactor trip on July 6. The lack of past (December 1996/January 1997) knowledge in adjusting the amplifiers was the cause of the generator not responding to a grid perturbation. Aside from some minor deficiencies, the recent work activities (calibration check and adjustment of the Unit 2 voltage regulator) were performed in accordance with approved procedures with engineering and supervisor oversight.

III. Engineering

E1 Conduct of Engineering

E1.1 Unqualified Thermal Insulation Found in the Reactor Buildings

a. Inspection Scope (37551, 92903)

The inspectors reviewed PIPs, engineering calculations, and interviewed engineering personnel following the discovery of additional unqualified insulation in the Reactor Buildings (RB).

b. Observations and Findings

During the inspection documented in IR 50-269,270,287/96-20, a number of conditions were identified by the residents that required technical evaluation by the licensee. Tape, loose paint, and insulation without supporting documentation were found in significant quantities in various locations in the Unit 2 RB. These were of concern due to the requirements of 10 CFR 50.46 to ensure long-term cooling. Tape, paint, and insulation were removed from the Unit 2 RB, and later in the Unit 1 RB (Unit 3 exhibited similar conditions, but was still in its refueling outage and not ready for closeout inspections). Power Chemistry Materials Guide Program, SDQA Plan "D", did not address insulation and tape used in the RBs.

During that inspection period, the licensee removed material from the Unit 2 RB to ensure a recirculation flow path during emergency conditions and due to the fact that for certain fibrous insulation and tape present in the RB, there was no clear specification for its use. The inspectors questioned the acceptability of the licensee's evaluation for past RB recirculation operability (OSC-6827, Rev 0, Oconee Nuclear Station Units 1, 2, and 3 Emergency Sump Operability Evaluation, dated

January 24, 1997). At the end of that inspection period, the licensee was re-evaluating past operability conditions for the RBs. In January 1997, this item had been identified as URI 50-269,270,287/96-20-05, Past Operability of RB Recirculation Flow Path.

One of the URI operability concerns involved the lack of bolting for the emergency sump cover plates. This item was closed in IR 50-269,270,287/97-05. The other concern involved the operability of the emergency sump due to material left in the RB such as tape and insulation. The licensee completed a calculation (OSC 6827, Emergency Sump Operability Evaluation) based on the amount of unqualified or questionable insulation found and removed from the RB. This was documented in PIP 0-097-0287 as past and present operable for all units on January 24, 1997. This PIP was closed by the licensee on March 11, 1997.

On June 23, 1997, unqualified thermal insulation was identified by the licensee during a Unit 1 RB walkdown of the shutdown unit. Subsequently, unqualified insulation was also identified on Unit 2 and Unit 3, which were at power. Unit 1 was shutdown for inspection of the High Pressure Injection nozzles, Unit 2 was at 100 percent power, and Unit 3 was at 15 percent power due to seal oil problems. Unit 2 reduced power to less than 20 percent for a more complete inspection and removal of the subject insulation.

The unqualified insulation removed from all three units in June 1997 was as follows:

	Volume (cubic feet)	Area (square feet)
Unit 1	7.52	45.13
Unit 2	1.53	9.18
Unit 3	3.44	20.88

The insulation was removed, LER 269/97-07 was submitted, and PIP 0-097-1971 was generated. PIP 0-097-1971 documented the fact that the previous operability evaluation (PIP 0-97-0287 from IR 96-20) for the emergency sump was completed with inaccurate data. Specifically, confirmation had been received for OSC-6827, Emergency Sump Operability Evaluation, that all unqualified insulation had been removed from the RBs.

c. <u>Conclusions</u>

Pending past operability evaluation results (PIP 0-097-1971), URI 50-269,270,287/96-20-05, Past Operability of RB Recirculation Flow Path, will remain open.

E2 Engineering Support of Facilities and Equipment

E2.1 Electrical Modification of Keowee Control System

a. Inspection Scope (37828)

The licensee's engineering, operations, maintenance, and quality control personnel installed and tested electrical modifications involving the FFB associated with Keowee Units 1 and 2 relay logic control systems. The modifications involved the FFB relay logic. The licensee had previously identified the Keowee units as being operable but degraded, based on the fact that the FFB would cycle open and closed several times during emergency starts. This contributed to the blown fuse in the relay logic network described in Section 01.2.

b. Observations and Findings

The inspectors reviewed documents and observed the modification installation and testing on July 8. Among the documents reviewed and used to control the installation and testing were the following:

- Minor Design Change (MDC) packages Oconee Exempt (OE)-10585 and 10586
- Procedure TN/4/A/ONOE10585/0 Instructions For The Installation of OE 10585 on Keowee Unit 2 and 10586 for Unit 1
- WO 97030693 and 97030696 For the Installation of the Design Changes
- Procedure PT/0/A/0610/024 Keowee Emergency Start for Trouble Shooting and Post Maintenance Checkouts

The observations included the pre-job briefings, design change installations, installation of measuring and test equipment (M&TE), and post modification testing. The installation of the modification was performed in accordance with design change packages OE-10585 and OE-10586. The controlling procedure used for the installation was TN/4/A/ONOE10585/0.

The modification consisted of removing an open logic signal for the FFB, jumpering out a close logic signal for the FFB, and adjusting the setpoint of FFB control relay SV(53-31T). The Unit 2 relay was adjusted from a setpoint of 72 volts to 83 volts at a frequency of 60 HZ. The control relay is both frequency and voltage dependant. Engineering and maintenance personnel checked the actuation of the relay at 30 HZ and 35 HZ. The relay performed satisfactorily.

The post modification testing was performed in accordance with procedure PT/O/A/0610/024. The post modification testing observation consisted of the following:

- At the completion of the modification and the installation of M&TE an automatic start was initiated on Keowee Unit 2. The inspectors did not identify any cycling of the FFB.

- After the automatic start test, an emergency start test was initiated. The inspectors observed that the FFB appeared to cycle at least three times.

The inspectors discussed the observation with the engineering personnel and were informed that relay SV(53-31T) would be adjusted to 100 volts at 60 HZ.

On July 17, the inspectors observed the installation and post modification testing of MDC OE-10586 on Keowee Unit 1. The inspectors also observed the adjustment and the post modification tests of Unit 2 relay SV(53-3IT). The inspectors noted that the same processes used for the Unit 2 MDC were also used for Unit 1. The SV(53-31T) relay for Unit 1 was adjusted from 68.9 to 100.0 volts at 60 HZ. The inspectors also observed that the Unit 1 FFB performed in accordance with the emergency start test acceptance criteria.

The Unit 2 relay was initially adjusted from 83 volts to 103.3 volts at 60 HZ. The reason the setpoint was placed at 103.3 was to verify the amount of margin above 100 volts. After a successful emergency start at 103.3 volts the relay was adjusted to 100.0 volts and the generator was successfully emergency tested.

c. Conclusions

The inspectors concluded that the Keowee Hydro Units' modifications were installed and tested in accordance with approved procedures, with engineering and supervisory oversight. Modifications met the acceptance criteria during the post modification testing. The modification and testing activities were completed thoroughly and professionally. The overall activities were considered excellent.

E3 Engineering Procedures and Documentation

E3.1 Changes, Tests, and Experiments Performed In Accordance With 10 CFR 50.59 (37001)

a. Inspection Scope

Between July 21 and July 25, 1997, the Senior Project Manager from the NRC Office of Nuclear Reactor Regulation conducted an on-site review of the procedure used at the Oconee Nuclear Station (ONS) to process safety evaluations in accordance with the requirements of 10 CFR 50.59. This regulation defines the conditions under which the licensee may make changes to the facility without prior NRC approval.

The review was performed using the guidance contained in NRC Inspection Manual Procedure 37001, dated December 29, 1992. Documents reviewed included:

- ONS 10 CFR 50.59 Annual Report submittal dated June 30, 1997
- ONS Annual FSAR Update submittal dated June 30, 1997
- Duke Power Nuclear Policy Manual Nuclear System Directive 209 (NSD-209), 10 CFR 50.59 Evaluation, Revision No. 5, Issue Date February 28, 1997, Effective Date March 10, 1997
- Duke Power Nuclear Policy Manual Nuclear System Directive 209, 10 CFR 50.59 Evaluation, Revision No. 6, Issue Date June 16, 1997, Effective Date August 4, 1997
- Duke Power Nuclear Policy Manual Nuclear System Directive 220, UFSAR Revision Process, Revision No. 0, Issue Date March 12, 1997, Effective Date March 26, 1997
- Oconee Nuclear Station Operator Training Guide #012, Oconee Training Center Simulator Configuration Management Guide, Rev. 04, Dated April 22, 1997

b. Observations and Findings

During the course of the review, the following findings/observations were made:

- The headings in the 10 CFR 50.59 Annual Report submittal for some entries state "Unit 1, 2, 3" and some indicate "Unit 1," "Unit 2," or "Unit 3," or various combinations. It is not clear whether the description means that the change has been incorporated for that unit or if it only affects that unit. Also there is no indication if the change has already been made on the other units. If a particular change is shown on the submittal as being made only to one unit, another entry should be contained in the appropriate subsequent submittal for the other unit(s).
- The Annual FSAR Update submittal cover letter indicates that changes made in the revision are indicated by a "6" (for 1996) in the margin of the changed pages. However, there were many pages in the submittal that had no such indication anywhere on either side of the page and some changes made to the text that did not have a "6" in the margin.

The licensee explained that the margin indication is only for changes of a substantive nature, not for changes to correct typos, spelling, or other nonsignificant changes.

- Section 13.5.2 of the Annual FSAR Update submittal, Operating and Maintenance Procedures, describes typical activities covered by normal and emergency procedures. However, there was no description of the Emergency Operating Procedures.

- NSD 209 is well written and clearly provides the instructions and documentation needed to perform accurate safety evaluations. It incorporated all of the formal procedural guidance suggested in the NRC Inspection Manual Chapter 37001, and contained the NRC Manual Chapter as a reference document used in its preparation.

  One administrative problem was the use of Revision 6 of NSD 209 before its Approved and Issued Date of August 4, 1997. It appeared that the procedure was being used prior to it being approved and issued. The Approved Date also appears at the bottom of each page of the procedure.

  In contrast to this, the date at the bottom of each page of Revision 5 of the procedure was the Issue Date, not the Approved Date. In addition, using an Effective Date that was 1-to-2 months beyond the Issue Date was confusing. The licensee was not able to explain the discrepancy or difference, but forwarded the concern to the appropriate Duke Power Company office for corrective action.

- The following safety evaluations were reviewed. No discrepancies were found that would affect the licensee's conclusion that the activity was being performed in accordance with 10 CFR 50.59. It was noted that temporary changes, including lifted leads and jumpers, if needed, were evaluated as proposed facility changes and are reviewed in accordance with NSD 209.

  - Procedure Change: #1 to TN/5/A/3000/00/AS1

  - Tests/Experiments: TT/3/A/0150/039, TT/0/A/0400/26, and TT/0/A/0620/030

  - Facility Changes: OE #8568, OE #8912, NSM-12873, and NSM-33001

  - Operability Determination: Problem Identification Program (PIP) No. 96-0232 (incorrectly identified as 96-0222 in the 10 CFR 50.59 Annual Report submittal)

- Temporary Change: TSM 1263

- FSAR Changes: 96-012 and 96-029

- The 10 CFR 50.59 Annual Report submitted June 30, 1997, described the "Oconee facility changes, tests, and experiments which were completed subject to the provisions of 10 CFR 50.59 between January 1, 1996, and December 31, 1996." It was submitted pursuant to 10 CFR 50.59(b)(2). A review of this report revealed that the process for generating it was not well controlled or reviewed and the content not sufficiently descriptive of the changes, tests, and experiments (CTEs) that were included. Specifically:

  - Even though the CTEs were completed during 1996, all but a few of the descriptions are written in the future tense; inappropriately indicating they have not yet been performed.

  - Section 50.59(b)(2) of 10 CFR states, in part, that the annual report shall contain a brief description, including a summary of the safety evaluations of each. Even though the descriptions of the CTEs were satisfactory, the content of the summary of the safety evaluations lacked sufficient detail in most cases. Most of the safety evaluation summaries simply contained a statement indicating that "No Technical Specification or UFSAR changes are required by this procedure change. No USQs (unreviewed safety questions) are created by or involved with this change."

    The inspector concluded that the safety evaluation summary could be more detailed and contain a brief explanation summarizing the basis for this determination. This would allow a reviewer to better understand the basis for the conclusion reached in the analysis. It was noted, however, that the summary complies with the Duke Power Company procedure guidance. The licensee was given examples of information that would result in a more complete submittal.

- In reviewing the UFSAR, the inspector found that UFSAR Table 12-3, page 1, lists monitor RIA-3 as "Reactor Building Shield Wall Unit 3." However, Technical Specification 3.8.1 states tnat "Radiation levels in the reactor building refueling area shall be monitored by RIA-3 and...." As a result, it appeared that there was no RIA-3 radiation monitor associated with Unit 1 or 2, even though they are required by the Technical Specifications. The licensee determined that this discrepancy had previously been self-identified and that administrative controls had been taken to correct the FSAR in the next UFSAR update. Thus, the error existed in the UFSAR, not in the Technical Specifications.

- Section 50.71(e) of 10 CFR requires that each licensee periodically update the FSAR to assure that the information contained in the FSAR contains the latest material developed. This submittal shall contain all the changes necessary to reflect information and analyses submitted to the Commission by the licensee or prepared by the licensee pursuant to Commission requirements since the last updated FSAR. The updated FSAR shall be revised to include the effects of: all changes made to the facility or procedures described in the FSAR; all safety evaluations performed by the licensee either in support of requested license amendments or in support of conclusions that changes did not involve an unreviewed safety question; and all analyses of new safety issues performed by or on behalf of the licensee at Commission request.

  In addition, 10 CFR 50.71(e)(4) requires that the FSAR revision reflect all changes up to a maximum of 6 months prior to the date of filing.

  In contrast to this, by comparing the FSAR changes indicated in the 10 CFR 50.59 submittal with the Annual FSAR Update Report submittal (both dated June 30, 1997), the inspector determined that of a total of 142 changes shown in the 10 CFR 50.59 submittal as having been completed in 1996, there were 33 that indicated FSAR changes would be needed but were not included in the Annual FSAR Update Report. In addition, since the details of the FSAR changes were an integral part of the 10 CFR 50.59 evaluations and there was at least 6 months from the end of the calendar year until the date of the submittal, sufficient time was available to include these changes into the UFSAR. As a result, the UFSAR submittal did not reflect all plant changes that occurred in 1996.

  The licensee was able to show that administrative controls (the generation of a PIP) were already in place to ensure that each of these changes would be incorporated into the next UFSAR submittal. In addition, the licensee showed that should another safety evaluation be performed that might need to use the missing UFSAR information, the procedure requires that the individual performing the evaluation would use this material even though it is not in the UFSAR (i.e., the preparer of the safety evaluation would not rely solely on the latest version of the UFSAR, but would search for other modifications that may have an affect on his analysis).

  As a result, it was determined that the problem had been identified by the licensee and appropriate actions were taken to correct it. In addition, as part of the PIP closeout evaluation, the licensee proposed to address actions to better control the process. Accordingly, 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. NCV 50-269,270,287/97-10-01: Failure to Accurately Reflect Modifications in the Annual UFSAR Submittal.

- During a previous site visit, the inspector attended a Plant Operations Review Committee (PORC) meeting on January 7, 1997. The subject of the meeting was Technical Specification Change No. TSC 96-11, Safety and Accident Monitoring Instrumentation. The discussion was thorough and in-depth. The PORC adequately performed the review and approval requirements of the licensee's 10 CFR 50.59 program.

c. Conclusions

The process used at Oconee to perform safety evaluations was found to meet the requirements of 10 CFR 50.59. However, a NCV was identified concerning a failure to accurately reflect modifications in the Annual Updated Final Safety Analysis Report Submittal.

IV. Plant Support Areas:

P1 Conduct of EP Activities

P1.1 Operational Status of the Emergency Preparedness Program

a. Inspection Scope (82701)

The inspector reviewed day-to-day routine operations and program initiatives to assess the effectiveness of the licensee's implementation of the Emergency Plan in meeting the regulatory requirements of Emergency Preparedness (EP). The following routine areas were reviewed:

- changes to the Emergency Plan and Implementing Procedures
- implementations of the Emergency Plan since the last routine inspection
- maintenance of selected emergency equipment and supplies
- status of emergency response facilities
- organizational changes and the impact on the emergency response program
- status of emergency preparedness training and training initiatives

- review of the independent audit report conducted since the last inspection

b. Observations and Findings

The inspector reviewed the changes made to the Emergency Plan since the last inspection and concluded the licensee performed satisfactory reviews prior to their implementation. The current Emergency Plan was revision 96-04 which had been submitted to the NRC with letter dated December 12, 1996. The effective date of the revision was December 16, 1996.

Since the last routine EP inspection, the Emergency Plan had been implemented three times as a Notification of Unusual Event (NOUE). On September 24, 1996, a NOUE was declared based on an unanticipated steam line failure within the plant, resulting in visible damage to permanent structures/equipment. On March 22, 1997, a NOUE was declared due to reactor coolant system pressure boundary leakage greater than 10 gpm. The third NOUE was declared on May 4, 1997, based on Emergency Coordinator judgment because of the inability to restore normal reactor coolant makeup prior to the end of the shift. The inspector's review of the licensee's documentation indicated declarations were within the basis of the Emergency Plan and required notifications had been properly made.

The inspector did not observe any problems with operability or calibration of emergency equipment randomly selected for inspection. A walk-through of the Technical Support Center, Operational Support Center, and the Emergency Operations Facility found the facilities to be maintained in a manner to support implementation of the Emergency Plan.

Recent organizational changes included a new Site Vice President and a new Engineering Manager as of July 1, 1997. Neither of the changes impacted the emergency organization because of the depth of personnel trained for emergency response organization (ERO) positions. Additionally, the Site Vice President was already qualified as a Public Spokesperson for Duke Power Nuclear Plants because of his previous position as a Site Vice President at a sister plant.

The inspector's review of the Emergency Response Training Program revealed a well organized and managed program that was supported by very good formal lesson plans. Additionally, the Training Instructor for EP had been very active in formulating and coordinating the training for Severe Accident Management Guidance training.

A review of the 10 CFR 50.54(t) independent audit report, Department Audit SA-96-08(ALL)(RA), dated October 31, 1996, identified no issues. The audit identified a very good working relationship between the utility and the offsite governmental agencies.

c. Conclusions

The inspectors found the emergency preparedness program to be maintained in a state of operational readiness and changes to the program to meet regulatory requirements. Program strengths noted by the inspector included the Emergency Preparedness training program and the number of personnel trained for Emergency Response Organization positions.

P1.2 Emergency Planning Drill

a. Inspection Scope (71750,82302)

The inspectors observed portions of the emergency drill conducted July 25, 1997.

b. Observations and Findings

The inspectors observed two instances of insufficient communication between the simulated control room and the Technical Support Center (TSC). In the first instance, operators in the simulated control room were not aware of the event classification until well after the scenario had passed to the Alert stage. When questioned by the inspector in the simulated control room during the drill, the operators were unsure of the actual classification. The operators only became aware of the classification when they questioned the on-shift manager (OSM) upon arrival in the simulator after the OSM was relieved as emergency coordinator.

In the second instance, the operators quantified a 1400 gallons per minute (gpm) leak on the Borated Water Storage Tank (BWST) resulting from a simulated tornado and asked for a damage report. The report they received indicated a 1 foot diameter hole in the tank approximately one third the length up from the bottom of the tank. The inspectors later learned that a tree was lodged in the tank as part of the scenario and that TSC personnel knew this; however, operators in the simulated control room never received this information.

During the scenario the operators proposed a plan to drain the BWST to the emergency sump, but the TSC decided against this plan due to possible debris getting into the sump. The inspectors observed some confusion by the operators as to why the TSC rejected their plan. Also during the scenario, the inspector questioned if a leakrate of 1400 gpm was too low for a one foot hole and again observed some confusion by the operators. They indicated that perhaps the scenario or the model were not exact, but did not question the report. The inspectors determined that missing information on the tree in the BWST resulted in this confusion.

The licensee documented both of these instances in their Problem Investigation Process (PIP) under Report Number 0-097-2317.

c. Conclusions

During the July drill, some communications between the simulated control room and the TSC could be improved. The licensee stated that logistics contributed to the communication problems in that the simulated control room and TSC were physically separated during a drill, whereas they would be closer during a real event. The inspectors concluded, however, that Unit 3 would be in a similar situation to that of the drill and that communications were still deficient.

Also, simulator control room staff did not maintain a questioning attitude regarding the damage report on the BWST. The tank leakrate calculated by the operators indicated a smaller hole than was reported in the damage report, yet operators did not question either the report or their calculations.

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Resident Inspector Tour of Public Document Room (PDR), Emergency Operations Facility (EOF), and County Emergency Operations Facility (CEOF) (71750)

The resident inspectors toured the Oconee county PDR located at the Oconee County Library, 501 W. South Broad Street, Walhalla, S.C. 29691. Required equipment and files were verified in good working order. The inspectors verified the equipment and files (on microfiche) by viewing and printing pages from inspection reports and letters.

The inspectors also toured the CEOF in Walhalla and the Oconee Nuclear Station EOF located in Clemson. The facilities were well organized with the requisite emergency communications and support equipment.

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 July 30, 1997.The licensee acknowledged the findings presented. Although reviewed during this inspection, proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Partial List of Persons Contacted

Licensee

E. Burchfield, Regulatory Compliance Manager
T. Coutu, Operations Support Manager
D. Coyle, Systems Engineering Manager
T. Curtis, Operations Superintendent
M. Nazar, Engineering Manager
B. Dobson, Systems Engineering Manager
W. Foster, Safety Assurance Manager
J. Hampton, Vice President, Oconee Site
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Manager
B. Peele, Station Manager
J. Smith, Regulatory Compliance

NRC
D. LaBarge, Project Manager
N. Economos, Regional Inspector
W. Sartor, Regional Inspector

Inspection Procedures Used

IP71750:	Plant Support Activities
IP71707:	Plant Operations
IP61726:	Surveillance Observations
IP62707:	Maintenance Observations
IP37551:	Onsite Engineering
IP37828:	Installation and Testing of Modifications
IP93702:	Prompt Onsite Response to Events at Operating Power Reactors
IP92901:	Followup - Operations
IP92902:	Followup - Maintenance
IP92903:	Followup - Engineering
IP62700:	Maintenance Program Implementation
IP55050:	Nuclear Welding General Inspection Procedure
IP37001:	10 CFR 50.59 Safety Evaluation Program
IP82302:	Review of Exercise Objectives and Scenarios
IP82701:	Operational Status of the Emergency Preparedness Programs

Items Opened, Closed, and Discussed

Opened

50-269,270,287/97-10-01	NCV	Failure to Accurately Reflect Modifications in the Annual UFSAR Submittal (Section E3.1)

Discussed

50-269,270,287/96-20-05	URI	Past Operability of RB Recirculation Flow Path (Sections E1.1)

List of Acronyms

ACB	Air Circuit Breaker
AIT	Augmented Inspection Team
ALARA	As Low As Reasonably Achievable
BWST	Borated Water Storage Tank
CEOF	County Emergency Operating Facility
CFR	Code of Federal Regulations
CR	Control Room
CRDM	Control Rod Drive Mechanism
EHC	Electro-Hydraulic Control
EOF	Emergency Operating Facility
FFB	Field Flash Breaker
FIP	Failure Investigation Process
GL	Generic Letter
GPM	Gallons Per Minute
HPI	High Pressure Injection
ICS	Integrated Control System
I&E	Instrument & Electrical
IR	Inspection Report
KHU	Keowee Hydro Unit
LCO	Limiting Condition for Operation
LDST	Letdown Storage Tank
LER	Licensee Event Report
LPI	Low Pressure Injection
LSS	Lee Steam Station
MDC	Minor Design Change
MFBMP	Main Feeder Bus Monitor Panel
MOV	Motor Operated Valve
M&TE	Measuring & Test Equipment
MTG	Main Turbine Generator
MVA	Mega Volts-Amps
MVAR	Megavolt-Amps-Reactive
MW	Megawatts
NDE	Non-Destructive Examination
OSM	On-Shift Manager
OTSG	Once Through Steam Generator
PDR	Public Document Room
PIP	Problem Investigation Process
RB	Reactor Building
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
TG	Turbine Generator
TS	Technical Specification
TSC	Technical Support Center
WO	Work Order