UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-269/94-38, 50-270/94-38 and 50-287/94-38

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-0001

Docket Nos.: 50-269, 50-270 and 50-287

License Nos.: DPR-38, DPR-47 and DPR-55

Facility Name: Oconee Units 1, 2 and 3

Inspection Conducted: November 27 - December 31, 1994

Inspector: KE Carroll for — 1/24/95
P. E. Harmon, Senior Resident Inspector — Date Signed

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L. A. Keller, Resident Inspector
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Approved by: R. V. Crlenjak — 1/25/95
R. V. Crlenjak, Chief, Branch 3 — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance activities, onsite engineering and technical assistance.

Results: One violation was identified for failure to follow procedures when transferring operation of the Keowee Hydro Unit from Remote to Local, paragraph 2.e.

The licensee's practices for performing on-line maintenance revealed that while no formal assessment is performed, on-line maintenance involving taking multiple components out-of-service is not routine at Oconee, paragraph 6.

A reactor trip of Unit 2 from 100 percent power occurred on December 8, 1994. The cause of the trip was a loss of power to the Integrated Control System (ICS) due to a loose lug on the power supply breaker. The unit was returned to power the following day, paragraph 2.c.

ENCLOSURE 2

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*B. Peele, Station Manager
*E. Burchfield, Regulatory Compliance Manager
*D. Coyle, Systems Engineering Manager
J. Davis, Engineering Manager
T. Coutu, Operations Support Manager
*W. Foster, Safety Assurance Manager
*J. Hampton, Vice President, Oconee Site
D. Hubbard, Superintendent, Instrument and Electrical (I&E)
C. Little, Electrical Systems/Equipment Manager
*J. Smith, Regulatory Compliance
*G. Rothenberger, Operations Superintendent
R. Sweigart, Work Control Superintendent

Other licensee employees contacted included technicians, operators, mechanics, security force members, and staff engineers.

*Attended exit interview.

2. Plant Operations (71707)

a. General

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification log, and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & electrical (I&E), and engineering personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and night shifts, during weekdays and on weekends. Inspectors attended some shift changes to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's Administrative Procedures. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

Unit 1 essentially operated at 100 percent power the entire reporting period.

Unit 2 experienced a reactor trip on December 8, 1994, due to a loss of control power to the ICS. The unit was restarted and was back on line December 9, 1994, and operated at essentially 100 percent power for the remainder of the reporting period.

Unit 3 essentially operated at 100 percent power the entire reporting period.

c. Unit 2 Reactor Trip

Responding to the Unit 2 reactor trip which occurred on December 8, 1994, at 2:24 p.m., the inspectors monitored control room operations during trip recovery. The trip resulted from a loss of power to the ICS which was caused by a breaker tripping in the circuit. A loose connection on the load side of the breaker terminal was determined to have caused the breaker to trip. The loss of power to the ICS generated a false "high steam generator level" signal which tripped the main feedwater pumps. Loss of both feedwater pumps in turn generated a signal that tripped the reactor. All systems responded appropriately and the reactor was shut down without adverse conditions noted.

As the loose lug could not be tightened, and the affected breaker (number 25 on the 2KI load center) could not be removed without de-energizing the entire load center, the breaker's outputs were swapped to an installed spare breaker (number 26). Oconee has not developed load lists for power supply breakers, so the consequences of de-energizing the entire 2KI load center could not be determined. The plant was restarted the following day and the turbine generator was on-line at 1:57 p.m.

The inspectors witnessed the operator's response to the reactor trip and reviewed the licensee's post trip report. The operators responded in a very professional manner and conducted the post trip actions in a very calm, organized fashion. The post trip review placed particular emphasis on the turbine by-pass valves' response to the trip. This was prompted by past problems when these valves repositioned to a random setting and failed to maintain proper steam generator inventory. Since that time, the licensee modified the control system, and the post trip review confirmed that the valves operated properly. The inspector determined that a thorough post trip review had been conducted, and that the operators had performed well in their response to the trip.

d. Unit 2 Control Room Instrumentation

The inspector noted that a total of 51 Unit 2 control instruments (including computer indications and alarms) were out-of-service or were not indicating correctly prior to the Unit 2 refueling outage which began on October 6, 1994. Since the outage has been completed, the inspectors have been monitoring the status of control room instrumentation. On December 30, 1994, a total of 37 instruments and computer points were listed as out-of-service or not indicating properly.

Based on the significant number of instruments with noted problems, it appears that more emphasis is needed to maintain control room instrumentation and assure that the operators have sufficient indications for operating the plant. At the end of the inspection period, the licensee had formed a task force to aggressively pursue restoration of out-of-service control room instruments. The inspectors will monitor the results of this team's efforts in future inspection reports.

e. Keowee Unit 1 Loss of Excitation

On December 11, 1994, Keowee Unit 1 tripped while connected to the grid at no-load conditions. The unit had been operability tested from the Oconee control room and the Local/Remote switch had been placed in Remote to perform the operability test. The dispatcher requested that control of the Keowee unit be transferred back to Keowee as soon as possible because of lake level letdown requirements. To accomplish this, Procedure OP/O/A/1106/019, Keowee Hydro at Oconee, requires shutting down the hydro unit prior to transferring control of the unit to Keowee. Recalling past hydro practices where the transfer was done with the unit on line, the Keowee operator, with concurrence from the Oconee control room, attempted to transfer control from Oconee to Keowee by depressing the Manual to Auto Control Transfer push button and taking the Local/Remote switch from Remote to Local.

When the Keowee operator attempted to transfer control of the Keowee unit from Remote to Local, the generator output breaker opened, the generator field breaker and field supply breakers opened and the voltage regulator transferred to manual. The Keowee Unit 1 turbine continued to operate, so the Keowee operator secured the Keowee unit by pressing the stop button.

Subsequent to securing the unit, the Keowee operator smelled smoke. Investigating, the operator found the closing coil on the generator field breaker smoking and racked out the breaker to deenergize the closing coil. The generator field breaker closing coil was replaced with a spare closing coil and the breaker was returned to service. The subsequent operability testing was satisfactory.

The loss of excitation resulted from momentary dropouts of the master run relays with the unit at speed-no-load conditions. The transfer could have possibly been accomplished if the Keowee unit had been loaded prior to the transfer from remote to local. The coil failure resulted from concurrent close and trip signals being applied to the generator field breaker and the breaker mechanism operating to the trip free condition prior to the closing coil being deenergized, resulting in the coil overheating.

The failure to operate the Keowee hydro station in accordance with approved procedures is identified as Violation 50-269,270,287/94-38-01: Failure to Follow Keowee Transfer Procedures.

f. Reactor Building Spray Inoperability Due to Inadequate Procedure

On December 27, 1994, the licensee performed a review of the abnormal procedure for loss of low pressure injection. For a postulated loss of coolant accident in which a single failure disables 1 of the 2 reactor building emergency sump lines, the abnormal procedure directs the operators to secure both reactor building spray pumps. The licensee determined that this condition was beyond the design basis assumptions contained in the maximum hypothetical accident safety evaluation report. The licensee declared both trains of reactor building spray inoperable on all three units and entered TS 3.0 at 4:45 p.m. TS 3.0 requires that the unit be placed in a hot shutdown condition within 12 hours.

To correct the procedural inadequacy the licensee initiated a procedure change to require that one train of reactor building spray be maintained operable assuming a postulated single failure of a reactor building emergency sump line. The procedure changes were completed and TS 3.0 was exited at 10:25 p.m. on December 27, 1994. The licensee was reviewing this item further to determine if the reactor building spray systems were actually inoperable as a result of the procedural inadequacy. The inspectors considered the licensee's action with regard to declaring the reactor building spray systems inoperable appropriately conservative and reviewed the proposed procedure changes. The inspectors will continue to review this item further.

Within the areas reviewed, one Violation was identified.

3. Maintenance and Surveillance Testing (62703 and 61726)

a. Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures adequately described work that was not within the skill of the craft. Activities, procedures and work orders (WO) were examined to verify that proper authorization and clearance to begin work were given, cleanliness was maintained, exposure was controlled, equipment was properly returned to service, and limiting conditions for operation were met. The following maintenance activities were observed or reviewed in whole or part:

(1) Reactor Protection System (RPS) Channel 'D' Main Feedwater Pumps and Main Turbine Trips Calibration, IP/0/A/0305/012

The inspector reviewed activities in progress during the calibration of pressure switch 2PS-419 on December 27, 1994. The work effort was being performed in accordance with calibration procedure IP/0/A/0305/012. RPS Channel 'D,' had been removed from service as specified in IP/0/A/0305/015, Nuclear Instrumentation RPS Removal From and Return to Service for Channels A,B,C and D for the switch calibration. The activity had been authorized per Work Order 94093207, Task 01.

The inspector determined that the activity was performed to acceptable standards, and no discrepancies were noted.

(2) Work Order 94093081, Task 01, Check/Calibrate Emergency Feedwater Pressure Switches

The inspectors observed activities in progress to calibrate the Unit 1 emergency feedwater pressure switches using procedure IP/0/A/0275/005I, Motor Driven Emergency Feedwater Pump Safety-Related Instrumentation Calibration and System Functional Check. The work activity was verified performed in accordance with the procedure and no maintenance discrepancies were noted during the performance of the work activity. Numerous pressure switches did not meet the calibration tolerance band stipulated in the procedure. This issue is discussed further in paragraph 4.

b. The inspectors observed surveillance activities to ensure they were conducted with approved procedures and in accordance with site directives. The inspectors reviewed surveillance performance, as well as system alignments and restorations. The inspectors assessed the licensee's disposition of any discrepancies which were identified during the surveillance. The following surveillance activities were observed or reviewed:

(1) Stroke Test of 3BS-1, IP/0/A/3001/016

Valve 3BS-1 is the 3A Reactor Building Spray Pump's discharge isolation valve. On October 16, 1994, Valve 3BS-1 exceeded the performance stroke testing requirements by one second. As discussed in Inspection Report 94-32, the licensee's evaluation concluded that maintenance performed during January 1994 altered the baseline for this valve and that this accounted for the slower stroke time. The licensee has instituted a weekly stroke test of Valve 3BS-1 to verify that the stroke time is not degrading. On November 30, 1994, the inspector observed one of these weekly stroke tests. The stroke time was 13.96 seconds, which was consistent with the previous stroke times. All activities observed were satisfactory.

(2) Standby Shutdown Facility (SSF) Instrument Surveillance, PT/0/A/600/20

This monthly surveillance verifies that the SSF control room instrumentation is operable and that it agrees with the corresponding instrumentation in the main control rooms. The inspector observed the surveillance check of the SSF Unit 1 RCS temperature instruments on December 19, 1994. During this check, the operators experienced great difficulty in getting all six RCS temperature gauges to go to mid scale as required. Eventually, the operators were able to complete the step as required. The inspector confirmed that operators properly filled out a test deficiency form for this problem. All activities observed were satisfactory.

(3) Keowee Hydro Operation, PT/0/A/620/09

On December 21, 1994, the inspector observed the performance of the monthly Keowee hydro test. Both hydro units started and supplied the Main Feeder Buses as required. All parameters were verified by the inspector to be within specifications. All activities observed were satisfactory.

(4) Reactor Protection System Control Rod Drive Breaker Trip and Timing Test, IP/0/A/305/14

Procedure IP/0/A/305/14 implements the requirements of Technical Specification (TS) 4.1.1, Table 4.1-1, Instrument Surveillance Requirements. This surveillance requires a monthly test of the control rod drive trip breakers. The inspectors monitored the performance of the procedure and verified that the acceptance criteria were met. No deficiencies were noted.

(5) High Pressure Service Water Pump and Power Supply, PT/0/A/250/05

Procedure PT/0/A/250/05 implements the requirements of TS 4.1.2, Table 4.1-2, Minimum Equipment Test Frequency. This surveillance requires a monthly functional test of the High Pressure Service Water pumps and power supplies. The inspectors reviewed the completed performance test conducted on December 31, 1994. No discrepancies were noted.

No violations or deviations were identified.

4. Onsite Engineering (71707)

During the inspection period, the inspectors assessed the effectiveness of the onsite design and engineering processes by reviewing engineering evaluations, operability determinations, modification packages and other areas involving the Engineering Department.

On December 7, 1994, during the performance of a routine calibration of the Unit 1 RPS feedwater pressure switches, four of the eight pressure switches were found out of calibration. These pressure switches, which are set at 770 psig, provide an anticipatory reactor trip signal on a loss of main feedwater. The as found setpoints for the out of calibration instruments ranged from 735 psig to 750 psig. These values exceeded the 15.5 psig maximum setpoint drift assumed in the uncertainty calculation assumptions. The pressure switches in question are Static-O-Ring model 9N6-W5-U8-C1A-JJTTNQ pressure switches. They had been installed during the previous refueling outage. These new pressure switches had also been installed in the emergency feedwater (EFW) initiation circuitry.

Based on the data obtained from the Unit 1 RPS switches, the licensee initiated a program to calibrate all the Static-O-Ring EFW and RPS pressure switches on all three units. The calibration of the switches was completed on December 14, 1994. Five of the six EFW pressure switches on Unit 1 were out of calibration. Eleven of the fourteen total feedwater pressure switches on Unit 2 were found out of calibration and twelve of the fourteen pressure switches on Unit 3 were found out of calibration.

The pressure switches were reset to the proper setpoint and a conditional operability evaluation was performed for all three units. The conditional operability evaluation concluded that the pressure switches could be considered operable if the calibration frequency was increased to weekly for Unit 3 and every two weeks for Units 1 and 2. Having reviewed the conditional operability determination and the calibration data collected since the problem was first identified, the inspectors concur with the licensee's conditional operability evaluation.

The licensee was still reviewing this issue at the end of the inspection period, but had already determined that portions of the Unit 1 and Unit 3 initiation circuitry were inoperable due to the excessive instrument calibration drift. The inspectors will continue to review this item in the future via the Licensee Event Report required to be submitted to the NRC per 10 CFR 50.73.

Within the areas reviewed, licensee activities were satisfactory and no violations or deviations were identified.

5. Cold Weather Preparations (71714)

The inspector reviewed the licensee's program to protect equipment and systems against extreme cold weather conditions. The program is outlined in Enclosure 5.12, Cold Weather Checklist of Operations Procedure, OP/1/A/1102/20, Shift Turnover, and is initiated via a computer alarm when the outside temperature reaches a low of 35 degrees F. The procedure checklist specifies various preventive measures to be implemented such as building doors closed, dampers closed, heaters turned on and operating properly, outside equipment cooling water at rated flows, trench covers in place, heat tracing operating properly and building heating systems in service.

In addition, alarm 1SA9B3, Reactor Building Ventilation Purge Inlet Temp Low, annunciates when the outside temperature reaches a low temperature of 40 degrees F. The response requires that various heater alarms be reviewed for malfunctions and steam supplies be readied for use per procedure OP/0/A/1106/22, Auxiliary Steam System.

The cold weather program was based on an evaluation of equipment where freeze protection was required and a compiled list of areas that have experienced problems with freezing. The inspector witnessed implementation of the procedure on December 1, 1994, when the outside temperature dropped to 35 degrees F. No discrepancies were identified during the inspector's review of the completed checklist, and the program was considered to be adequate.

6. Evaluation of On-Line Maintenance (TI 2515/126)

The objective of this inspection was to evaluate the impact on safety of the licensee's practices regarding the removal of equipment from service for on-line scheduled maintenance. The licensee indicated that it was their policy to limit the scope of maintenance activities being conducted simultaneously, and the scope of maintenance activities conducted on-line that could be accomplished during an outage. However, the licensee had no formalized process or procedures for assessing the risk associated with taking multiple components out of service at the same time for maintenance, or for doing maintenance on-line rather than during an outage. The inspector noted that the only formal mechanism for restricting maintenance activities were the requirements of TS. The inspector conducted a review of the maintenance history from January 1993 until December 1994 to determine the amount and frequency of maintenance performed during power operation. The inspector noted that it was rare for there to be multiple entries into Limiting Conditions for Operations (LCOs) for maintenance or testing. However, several specific examples when this occurred included:

- On January 12, 1993, the 3B Reactor Building Cooling Unit (RBCU), 3A Low Pressure Injection (LPI) pump, and Keowee Unit 1 were all out of service at the same time.

- On March 8, 1993, the Unit 1 Turbine Driven Emergency Feedwater (TDEFW) pump and 1B LPI train were both taken out of service for maintenance/testing simultaneously.

- On May 19, 1993, the 1C Low Pressure Service Water pump, containment isolation valve 1RC-7, and switchyard battery charger SY-2 were taken out of service at the same time.

- On October 4, 1993, the SSF, Unit 1 Emergency Condenser Circulating Water (ECCW), and the Unit 1 TDEFW pump were all taken out of service simultaneously.

Additionally, the inspector noted that following the most recent Unit 2 refueling outage the licensee entered the LCO for the Unit 2 RBCUs on three separate occasions to perform maintenance on cooler outlet valves (under the LCO for 9 days over a 15 day period). This maintenance was originally slated for completion during the outage, but was purposely deferred to on-line maintenance in order to prevent extending the outage duration.

The inspector concluded that in general the licensee limits on-line maintenance. However, there were no requirements, other than TS, to limit either the scope or frequency of maintenance conducted while at power. Additionally, there was no formal mechanism to assess the potential risks of conducting multiple maintenance/testing activities at the same time. The licensee indicated that as part of their planned implementation of the Maintenance Rule, they were preparing a matrix that would administratively prohibit certain combinations of maintenance activities based on insights gained from Probabilistic Risk Assessment (PRA). The inspectors noted that the licensee did perform a PRA as part of their planning for an extended outage of the Keowee overhead path. This outage activity, which lasted 14 days while all three Oconee units were on-line, consisted of reblocking the Keowee main transformer. The PRA concluded that the attendant work should be performed during periods of Oconee unit "innages."

No violations or deviations were identified.

7. Inspection of Open Items (92902 and 92903)

The following open items were reviewed using licensee reports, inspection record review, and discussions with licensee personnel, as appropriate:

a. (Closed) Unresolved Item 50-269,270,287/90-30-02: Clarification of TS 3.4.1.

As a result of this item the licensee submitted a TS change request to clarify the operability requirements of the emergency feedwater automatic initiation circuitry. This change was approved and incorporated into the TS by amendment 207 for Units 1 and 2, and amendment 204 for Unit 3. Based on the TS change, this item is closed.

b. (Closed) Unresolved Item 50-269,270,287/94-36-01: Failure To Meet SSF Activation Time Requirement

This URI was identified concerning the ability of Oconee operators to place the SSF into operation within 10 minutes. The licensee had determined that the SSF must be activated within 10 minutes of the onset of an SSF required event in order to prevent Reactor Coolant Pump (RCP) seal damage/failure and/or loss of natural circulation due to steam void formation.

On July 27, 1994, the licensee performed a drill that was written with the intent of showing how plant personnel and equipment were prepared to cope with mitigation of an Appendix "R" type event. The drill scenario included a requirement to activate the SSF. The SSF activation time for this drill was approximately 28 minutes. During this drill, it took approximately 8 minutes for the personnel to acknowledge the need to activate the SSF, and 20 additional minutes before the SSF was in service. The licensee indicated that this drill failure was an isolated instance and did not indicate that the SSF could not be activated within 10 minutes. The licensee based this on the "numerous successful testing of the 10 minute criterion" previously performed. The inspector noted that the only previous documented test for SSF activation was conducted on December 13, 1987. This was a single unit scenario in which the total elapsed time was 9 minutes, 26 seconds.

The inspector observed a training exercise during the previous inspection period and noted that the exercise did not account for the time required for the necessary valve manipulations (valves were not actually stroked during the drill, rather the valves were assumed to go instantly open or closed). Additionally, the inspector noted that completing the procedure as written within ten minutes was extremely challenging. The inspector noted that the necessary valve manipulations would add approximately one minute to the activation time, and that this apparently had not been accounted for in previous drills/tests. Due to the lack of documentation, it was impossible to determine if factoring in the valve stroke times into the previous tests would have resulted in test failures.

The licensee agreed that valve stroke times should be included in any future drill/test used to verify that the SSF could be placed into operation within 10 minutes. The licensee concluded that valve stroke times would add 56 seconds to the Unit 1 activation time, 75 seconds to Unit 2, and 58 seconds to Unit 3.

On December 7, 1994, the inspectors observed a special drill which was conducted to verify that the SSF could be placed in service within 10 minutes with valve stroke times included. The licensee's scenario for this drill assumed all Turbine Building components were simultaneously destroyed by a fire. This required full activation of the SSF in order to provide Reactor Coolant Makeup and Auxiliary Service Water to all three Oconee units. The results of the drill were as follows:

Unit 1: 9:46
Unit 2: 10:48
Unit 3: 10:00 (times in minutes:seconds)

A conference call was held between the licensee and NRC (Region II and NRR) to discuss issues associated with the recent drill failures. During the call the licensee maintained that the recent drill failures indicated the need for additional operator training and procedural enhancements, but did not indicate that the SSF was inoperable. The licensee subsequently conducted additional operator training and revised the SSF activation procedure. The licensee then performed another three unit drill scenario on December 20, 1994, similar to the one conducted on December 7, 1994. The results of the drill were as follows:

Unit 1: 6:17
Unit 2: 6:05
Unit 3: 6:18 (times in minutes:seconds)

The licensee indicated that they would continue to perform periodic drills in order to test all shift personnel. The inspectors will continue to follow the licensee's drills. Based on the last drill, the inspectors concluded that the licensee's training and procedures had improved sufficiently to provide reasonable assurance that the SSF could be manned within 10 minutes. The inspectors concluded that the failure to factor in valve stroke times in drills conducted prior to December 7, 1994, constituted a weakness in the licensee's test program for the SSF.

8. Review of Licensee Event Reports (92700)

The below listed Licensee Event Reports (LER) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, compliance with Technical Specification and regulatory requirements, corrective actions taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. The following LERs were closed:

a. (Closed) LER 269/92-09: Unit 1 RCP Seal Leakage Exceeds 4 1/2 Gallons

The licensee made an evaluation on July 22, 1992, that the SSF Make-up Pump (MUP) was inoperable when Unit 1 was shut down on May 24, 1992, due to a capacity restraint that was exceeded when 1A2 RCP seal leakage exceeded 4.5 gpm. During the unit shutdown, the RCP seals were inspected. It was discovered that obsolete (black) seals had been installed in each of the RCPs and this was the source of the excess leakage observed from the 1A2 RCP seal. The obsolete seals were replaced with the proper seals (tan) and the unit was returned to service on June 9, 1992. In addition, the obsolete seals were removed from inventory and maintenance procedure, MP/A/A/1310/004A, Seals RCP - Westinghouse Controlled Leakage - Removal, Inspection, and Installation was revised to specify the correct seals to be installed.

On December 14, 1994, the inspector reviewed the referenced procedure change (change 22) and both the supply and seal return flows for the Unit 1 RCPs. The corrective actions taken by the licensee were determined to be acceptable. Accordingly, this LER is considered closed.

b. (Closed) LER 270/93-01: U2 Trip/KI Loss/Loss of Main Feedwater

During a shutdown of Unit 2 for a refueling outage on April 4, 1993, alarm "MS Pressure Mismatch" annunciated. The reactor temperature was at 536 degrees F and the turbine bypass valves were closed. At that time, control room indicators began to fluctuate and the operating feedwater pump tripped. The reactor operator manually tripped the reactor.

During the event, the operators found that the 2A turbine bypass valves were tripped to manual and throttled. The partially open 2A bypass valves had been responsible for the erratic indications observed. The operator took manual control and closed both the 2A and 2B bypass valves to control steam line pressure and reactor cooldown.

The opening of the 2A bypass valves was determined to have been caused by a momentary loss of the 2KI inverter power prior to rapid transfer to the backup power supply. The loss of the 2KI power was a result of a blown fuse. It was further learned that when the 2KI was re-powered from the backup source, the Static Analog Memory (SAM) module allowed the bypass valves to reset at a random position. A similar event occurred in Unit 3 on August 10, 1994, following a loss of the "3KI" inverter. Again, the SAM module allowed the turbine bypass valves to reset at random positions. However, the 1994 event resulted in a dryout of the 3B Once Through Steam Generator and the licensee had to enter the Emergency Operating Procedures to recover the plant. Violation 269,270,287/94-23-94 was issued because of the licensee's failure to take the necessary actions to correct the bypass valve problem in a timely manner.

The licensee determined the inverters (i.e., KI, KU, and KX) to be aged and no longer reliable. As a result, the inverters on Units 1 & 2 have been replaced and those for Unit 3 have been procured and scheduled for replacement during the next refueling outage. The SAM modules were finally replaced after the August 10, 1994 event with modules which reset the turbine bypass valves back to the closed position after a power loss.

Based on the licensee's evaluations and corrective actions, this LER is closed.

c. (Closed) LER 270-92-04: Loss of Off-site Power and Unit Trip Due To Management Deficiency, Less Than Adequate Corrective Action Program

On October 19, Oconee Unit 2 experienced a Loss of Off-site Power event, a generator load rejection, and a Unit 2 trip from 100 percent power. A battery charger had been placed in service without a connected battery. This produced excessive voltage swings which caused a series of switchyard breaker failure relays to actuate, locking out both the red and yellow buses in the 230 KV switchyard. These relays had previously been identified by the licensee as susceptible to spurious operation due to excessive voltages in 1980, but were not modified as recommended by the manufacturer (Westinghouse). Lockout of the switchyard caused a Unit 2 trip, a temporary loss of power, and startup of the emergency power source (a Keowee emergency generator).

During recovery, the Keowee operator reset the emergency start signal, which tripped the emergency generator and resulted in a second loss of power on Oconee Unit 2.

Extensive corrective actions proposed in this event report have been completed with the exception of an upgrade in the emergency lighting at Keowee, which is currently scheduled for November 1995. The proposed corrective actions have been reviewed and found acceptable.

This item is considered closed.

9. Exit Interview

The inspection scope and findings were summarized on January 5, 1995, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary and listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Description/Reference Paragraph
50-269,270,287/94-38-01	VIOLATION: Failure to Follow Keowee Transfer Procedure (paragraph 2e).