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

Report Nos.: 50-269/94-11, 50-270/94-11 and 50-287/94-11

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: March 27 - April 30, 1994

Inspectors: R. E. Carroll Jr. for 5/19/94
P. E. Harmon, Senior Resident Inspector — Date Signed

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Approved by: Marvin V. Sinkule 5/17/94
M. V. Sinkule, Chief, — Date Signed
Reactor Projects Branch 3

SUMMARY

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

Results: A maintenance weakness was identified due to the failure to perform preventive maintenance on torque switch contacts for Limitorque motor operated valves. Oconee Unit 3 did not perform routine maintenance to keep torque switch contacts clean as recommended by the manufacturer. This was identified during a review of a failure involving a motorized valve operator (paragraph 3.a).

During two plant transients, a unit trip caused by loss of feed pumps (paragraph 2.c) and a runback caused by a dropped rod (paragraph 2.d), weaknesses were observed in work control scheduling, procedure adequacy, and operator knowledge.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*B. Peele, Station Manager
M. Bailey, Regulatory Compliance
S. Benesole, Regulatory Compliance Manager
D. Coyle, Systems Engineering Manager
*J. Davis, Engineering Manager
B. Dolan, Safety Assurance Manager
W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
D. Hubbard, Component Engineering Manager
C. Little, Superintendent, Instrument and Electrical (I&E)
*S. Perry, 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 conducted on a routine basis throughout the reporting period. During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

Unit 1 operated at power until April 28, 1994, when the unit was shut down for a scheduled refueling outage. On April 7, 1994, power was reduced to approximately 55 percent due to a dropped rod. The rod was recovered and the unit returned to full power on April 8, 1994. See paragraph 2.d for details.

Unit 2 experienced a reactor trip at 11:08 a.m., on April 6, 1994, and was returned to service 4 days later. The unit operated at power for the remainder of the inspection period. See paragraph 2.d for details.

Unit 3 operated at power throughout the inspection period.

c. Unit 2 Trip

On April 6, 1994, at 11:08 a.m., Unit 2 tripped from 100 percent power due to a sequential loss of both main feedwater pumps. All control rods fully inserted and decay heat was controlled by the turbine bypass valves to the main condenser with feedwater supplied by the 2B Motor Driven Emergency Feedwater Pump (MDEFWP) and the Turbine Driven Emergency Feedwater Pump (TDEFWP). Due to maintenance activities, the 2A MDEFWP was not available and the unit was in a Limiting Condition for Operation (LCO).

The event leading up to the trip began when the 2B Main Feedwater Pump (MFWP) shaft driven oil pump failed, causing the 2B MFWP to trip on low oil pressure. As a result, the integrated control system generated a reactor power runback from 100 percent of rated capacity to 65 percent. Feedwater pressure and flows became erratic while operating on the available MFWP (2A). The reactor operator took manual control of the feedwater regulating valves in an effort to stabilize the condition. However, the 2A MFWP speed control system did not respond to the adjusted flow rates and resulted in a high differential pressure across the regulating feedwater valves. This condition resulted in the 2A MFWP tripping on a high discharge pressure and a subsequent reactor trip. The TDEFWP and the 2B MDEFWP started when the 2A MFWP tripped.

Licensee investigation into the 2A MFWP trip revealed that a loose set-screw on the pump's speed control linkage was responsible for the loss of pump speed control. Also revealed, was that the motor gear unit (MGU) utilized to operate the subject linkage had failed and been replaced on April 3, 1994. In retrospect, the licensee attributed the earlier MGU failure/replacement to the defective linkage causing excessive and ineffective attempts by the motor to meet the demands of the control system.

The inspectors had noted that the 2A MDEFWP was out of service on April 5, 1994 (the day prior to the trip). The pump was out of service to replace an electrical cable to pressure switch PS-386 in the automatic start circuitry. The cable was not replaced that day and the pump was returned to service that evening. The pump was again taken out of service on the morning of the trip for the same work. Prior to the trip, the inspectors questioned the licensee as to why the work was not done on the day before as originally scheduled; thereby, avoiding an additional day of having the plant in an LCO. The licensee responded that a breakdown in the recently reorganized work control system had occurred. Delays in starting the work resulted in the day shift work crews deciding to defer the work until the following day.

The failure to perform scheduled work on equipment taken out of service, specifically that which puts the plant in an LCO, was identified as a weakness in the work control system.

The licensee determined that the "E" breakers did not transfer the tripped unit to the startup transformer as rapidly as designed when the reactor tripped. As part of the post-trip review process, the licensee determined that a slow transfer of the "E" breakers is acceptable. Since this problem occurred previously in 1989, the licensee initiated Problem Investigation Process (PIP) Report 2-94-480 to investigate the problem and define corrective actions. This will be identified as Inspector Followup Item 270/94-11-01: Slow Transfer of The "E" Breakers.

d. Unit 1 Dropped Rod

At 9:55 a.m., on April 7, 1994, control rod 6 in group 5 dropped from the full out position to the full in position. The rod is located at core location O-6, on the periphery of the core. The rod dropped during the performance of procedure PT/0/A/600/15, Control Rod Movement. At the time the rod dropped, the operators had transferred the rod to the auxiliary power supply and were exercising the rod in an effort to stop the rod out limit light from flashing. The operators attempted to return the control rod drive Diamond control panel to automatic to allow the integrated control system to automatically reduce power to 60 percent due to the asymmetric rod fault runback. However, the control system would not return to automatic. The Diamond station would not return to automatic due to an interlock that requires proper sequencing for automatic rod movement.

The operators declared group 5 rod 6 inoperable and commenced a power reduction to less than 60 percent power as required by the TS. TS 3.5.2.2.b.3 requires that a control rod be declared inoperable if the rod is misaligned with its group average by greater than 9 inches. TS 3.5.2.2.d requires that an inoperable rod be restored to operable status within 1 hour or continue power operation with the control rod declared inoperable and within 1 hour verify shutdown requirements with an additional allowance for the withdrawn worth of the inoperable rod and reduce reactor power to less than 60 percent of the allowable power for the reactor coolant pump combination. TS 3.5.2.2.d also requires that the nuclear overpower trip setpoints be reduced to 65.5 percent power within the next 4 hours. Reactor power was decreased below the 60 percent TS requirement at approximately 11:23 a.m.

A work request was initiated to investigate/repair the Group 5 Rod 6 failure. The licensee inspected the power fuses for the stator and determined that they were not blown and then performed phase to phase resistance checks on the stator. Initial testing indicated that an electrical short existed on phases C and CC. A short between the two phases would cause power removal from the stator and result in a rod drop. Following the initial resistance checks the rod was returned to the auxiliary power supply and phase to phase resistance checks reperformed. The subsequent checks indicted that a phase to phase short did not exist between phase C and CC. The licensee then checked the auxiliary power supply with an oscilloscope and checked cabinet connections for loose connections. No problems were identified.

After the troubleshooting activities were completed and no definite cause could be determined, the control room operators attempted to relatch the control rod and return it to the full out position. The rod latched and was successfully withdrawn to the full out position at approximately 2:18 p.m. During the rod withdrawal evolution a problem was identified with the operating procedure (OP/0/A/1105/09). The procedure indicates that if power increases as a result of withdrawing the dropped rod, the other regulating groups are to be inserted to offset the power increase. To accomplish this, the procedure specifies that the operator go to group select and sequence/insert the other regulating rods. However, with Group 5 not at the out limit, Group 7 was not capable of sequencing. Fortunately, this procedure problem did not affect the rod withdrawal because a significant power increase did not occur when Group 5 Rod 6 was withdrawn. Several minutes elapsed before the operating staff realized that an interlock inhibited the sequencing of the Group 7 rods. It was evident to the inspectors that the operators were not intimately familiar with the interlocks of the rod control system. The licensee plans to revise the operating procedure to give operators proper instructions for recovering a dropped regulating rod.

In conjunction with the rod recovery efforts, I&E personnel attempted to reset the nuclear overpower trip setpoints to 65.5 percent. The I&E personnel were unable to set the trip setpoints to 65.5 percent using the approved procedure (IP/0/A/0301/03U). Subsequent investigation determined that the procedure had been revised and that the setpoint specified in the procedure was in error because the procedure assumed that a gain potentiameter was being used to set the trip setpoint. At reduced power level, the gain potentiameter does not provide enough gain to reset, and an additional bias potentiameter is required to be adjusted. The procedure problem does not affect the setting of the overpower trip setpoints at 100 percent power because a gain potentiameter alone is used to set the trip setpoints. Group 5 Rod 6 was returned to the full out position prior to the TS time requirement for resetting the nuclear overpower trip setpoints was exceeded.

The licensee decided to remain at approximately 55 percent power until the procedure for resetting the nuclear overpower trip setpoints was revised and reactor protection system (RPS) channels A and B were reset to 65.5 percent to verify that the procedure could be accomplished in a timely manner prior to exercising Group 5 Rod 6 on the auxiliary power supply. The procedure was revised and RPS channel A was successfully reset without incident. During the calibration of RPS channel B, RPS channel A tripped on a flux/flow/imbalance trip signal at 9:47 p.m. At the time RPS channel A tripped, RPS channel B had been reset to 65.5 percent, but was still in trip bypass. RPS channel B also received a trip signal on flux/flow/imbalance. If RPS channel B had not been in trip bypass when channel A tripped, a reactor trip would have occurred. The licensee reduced reactor power approximately 2 percent to provide more margin to a reactor trip signal. The licensee also reset the nuclear overpower trip setpoints to the normal 100 percent values.

At approximately 11:00 p.m., the operators inserted Group 5 Rod 6 to approximately 95 percent using the auxiliary power supply and then returned the rod back to 100 percent without incident. A power increase to 100 percent was initiated at 11:15 p.m. after the rod was exercised. The Unit was returned to 100 percent power at approximately 7:00 a.m., on April 8, 1994.

The inspectors observed the power reduction and the licensee's actions to recover Group 5 Rod 6. Weaknesses were observed in the operators' knowledge of the rod control system interlocks, the operating procedure for recovering the dropped rod, and the instrument procedure for resetting the nuclear overpower trip setpoints. If the dropped rod had not been recovered, the TS requirement for resetting the nuclear overpower trip setpoints within 6 hours would not have been achieved. This circumstance would have required a unit shutdown. A weakness was also identified in the control of reactor power level during the time period that RPS channels A and B were being reset to 65.5 percent power. Although power level was maintained below 60 percent, inherent power oscillators at reduced power level had not been taken into account. Consequently, a reactor trip would have occurred if RPS channel B had not been in trip bypass. The licensee initiated the problem investigation process to identify and correct the problems associated with this event.

Within the areas reviewed, no violations or deviations were identified. A weakness was identified in the work control system as documented in paragraph 2.c above. Weaknesses were identified in the operators' knowledge of the rod control system interlocks, the operating procedure for recovering a dropped rod, the I&E procedure for resetting the nuclear overpower trip setpoints, and the control of reactor power level as documented in paragraph 2.d above.

3. Maintenance and Surveillance Testing (62703), (61726)

a. Maintenance Activities

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 were examined to verify that proper authorization to begin work was given, provisions for fire were made, cleanliness was maintained, exposure was controlled, equipment was properly returned to service, and LCOs were met.

Maintenance activities reviewed/witnessed in whole or in part:

- Work Order 94016820, Task 01, Troubleshoot failure of 3MS-33 to fully open.

  On April 28, 1994, The unit supplying the auxiliary steam system for all three units was switched from Unit 1 to Unit 3. When attempting to open 3MS-33 (the steam supply from the "B" Main Steam header) from the control room, the valve did not fully open. 3MS-33 is included in the licensee's Generic Letter 89-10 program due to its importance to safety (used to mitigate certain design basis events such as steam breaks and steam generator tube ruptures). Subsequent investigation by the licensee revealed dirty contacts on the torque switch. The contacts were cleaned and the valve was successfully stroked. The inspector reviewed the maintenance history for this valve and noted that the operator was recently refurbished during the Unit 3 refueling outage (February 1994). Neither the refurbishment procedure, nor any of the licensee's mechanical or electrical preventive maintenance procedures associated with Limitorque operators, required cleaning the torque switch contacts.

  The inspector noted that Limitorque's manual, Maintaining Equipment Qualification On Limitorque Valve Actuators, specified that "The limit and torque switches have silver contacts which must be kept clean and free of corrosion. Silver contacts should be burnished, do not use abrasives to clean these contacts". The guidance did not include specifics on how to clean the contacts or the frequency of cleaning. The inspector concluded that the failure to include requirements to periodically clean/burnish torque switch contacts was a preventive maintenance weakness in that it could affect valve operability, as evidenced by the failure of 3MS-33. The inspector noted that nearly all Limitorque motor operated valve (MOV) operators at Oconee could be affected at some point during the valve stroke by defective torque switch contacts (i.e., torque switch is bypassed during the first 5 percent of open travel and the first 5 percent of close travel for globe valves).

The licensee later determined that their Limitorque electrical preventive maintenance procedure (IP/0/A/3001/001) previously required cleaning torque switch contacts. However, this requirement was inadvertently omitted during revision 35 to this procedure on November 10, 1993. The licensee therefore concluded that this preventive maintenance omission only affected Unit 3 due to the fact that the only opportunity to use this revised procedure was the recent Unit 3 outage. The licensee also noted that there was one other similar failure that occurred during Engineered Safeguards (ES) testing following the recent Unit 3 outage to valve 3RC-6 (pressurizer sample isolation valve). As the two valve failures (apparently due to dirty torque switch contacts) occurred over a relatively short period of time since the missed preventive maintenance, the inspectors expressed concern with the implications on reliability of the Unit 3 Limitorque MOVs.

The licensee immediately initiated procedure changes to include guidance on maintaining torque switch contacts. Additionally, the licensee is evaluating when they can perform the torque switch cleaning that was missed due to the omitted procedure step (approximately 56 valves). The inspectors will continue to follow the licensee's corrective actions for this issue. This matter is identified as Inspector Followup Item 50-287/94-11-02: Torque Switch Maintenance.

- Work Order 94023591, Task 01, Repair of the 3C Condensate System Air Ejector Relief Valve 3MS-70.

  Due to 3MS-70 passing steam, the valve was removed and inspected. The inspection revealed seat and disc damage. The technicians that performed the inspection stated that the valve damage was probably the result of system over-pressurization and subsequent relief valve chatter. The valve was rebuilt and bench tested. The inspector observed the bench testing which revealed that the lift setpoint was correct. A PIP was generated to determine the cause of the relief valve failure and corrective actions.

- Work Order 94023922, Task 01, Inspect and/or Replace Strain Insulators on the Keowee Overhead Power Path.

The work order was initiated to replace the insulators on the Keowee overhead power path line due to a potential problem with shrinkage of the cement used in manufacturing the insulator. The shrinkage could result in failure of the insulator. The problem was identified for a specific insulator manufactured by GE/Locke in the 1969-1970 time frame. The licensee was unable to determine if these insulators were installed on the transmission line from Keowee to Oconee.

The inspectors witnessed a portion of the work activities performed. The licensee originally planned to replace all the insulators on the transmission line and then inspect the replaced insulators. During the replacement activity the licensee determined that the new insulators were not an exact replacement for the old insulators. Consequently, the licensee inspected the existing insulators to verify that they were not the suspect insulators and returned the Keowee overhead line to service. The inspector reviewed the work package and verified that TS requirements were met with respect to emergency power supplies. Other than the above noted problem, no deficiencies were noted.

b. Surveillance Testing

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The inspectors witnessed the tests in whole or in part, to verify that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, tests results were acceptable and system restoration was completed.

Surveillances reviewed/witnessed in whole or in part:

- 125 Vdc Instrument & Control Battery Service Test And Annual Surveillance (IP/0/A/3000/003)

  This surveillance demonstrates that the control batteries are capable of delivering the power required during a Loss Of Coolant Accident (LOCA) for a period of one hour, and satisfies the requirements of T.S. 4.6.10. The inspector noted that all measured parameters were well within limits.

- Isolating Transfer Diodes Preventive Maintenance and Peak Inverse Voltage Test (IP/0/A/3000/006)

This surveillance ensures optimum isolating transfer diode performance is maintained by identifying diodes with excessive leakage current. The inspector witnessed portions of the test performed for the Unit 3 isolating transfer diodes on April 14, 1994. All activities observed were satisfactory and all parameters measured were well within limits.

- Engineered Safeguards System Logic Subsystem 2, LPI Channel 4 On-Line Test (IP/0/A/0310/013B)

  On March 28, 1994, the inspectors reviewed activities during the performance of the Low Pressure Injection Channel 4 On-Line Test. The purpose of the test was to functionally check operation of the Engineered Safeguards (ES) Logic Subsystem and to meet the requirements specified in TS 4.4.1 and 3.5.1.1. During the inspectors' review, all work was performed per the procedure and no discrepancies were noted.

- Safe Shutdown Facility (SSF) Diesels, Operational Inspection and Checks (MP/0/A/5050/017)

  The inspector reviewed activities in progress associated with the inspection of the SSF diesels on April 4, 1994. The work effort was performed as authorized by Work Order Task 94025176-01 and included the requirements specified per MP/0/A/1800/001, Tool and Material Inventory Checklist On Operating Safety-Related Systems. In addition, MP/0/A/5050/033, Diesel - SSF - 12 and 16 Cylinder - Oil sample Collection, was specified to include the requirement and instructions for collecting and sampling the engine lubricating oil. The work was performed in accordance with the applicable procedures.

- Standby Bus Lockout Test (TT/0/A/0610/07)

  The purpose of this special test procedure was to verify that the standby bus lockout relays operate and interface with the emergency power switching logic properly. This test was initiated as a result of the licensee problem identification process that identified on January 17, 1994, that the bus lockout relay portion of the emergency power switching logic was not being completely tested on the standby busses and the main feeder busses of all three units. The licensee plans to test the main feeder bus lockout relays during each unit's refueling outage.

  The inspectors reviewed the test procedure and witnessed the testing conducted on standby bus 1 and standby bus 2. The bus lockout feature operated as designed and the procedure acceptance criteria was met. Minor procedural problems were encountered during the performance of the test procedure, but were resolved satisfactorily prior to continuation of the test.

- Auxiliary Service Water (ASW) Pump Test (PT/0/A/251/10)

  The purpose of this test procedure was to verify the performance of the ASW pump in accordance with ASME Section XI Code requirements. The procedure is performed on a quarterly basis and establishes flow through a test line that returns to the condenser circulating water system. The TS do not require this test to be performed, but the licensee's in-service test program requires that this pump be tested.

  The inspectors witnessed the performance of this test procedure on April 13 and April 15, 1994. During the test conducted on April 14, the pump did not develop sufficient indicated flow to meet the acceptance criteria contained in the procedure with the test line fully open. The maximum flow rate obtainable was 1139 gpm. The licensee calibrated the flow instrument in the test line, replaced the dampers in the flow instrument and reperformed the test procedure on April 15. After calibration of the flow instrument, indicated flow increased to 1160 gpm with the test line fully open. This value was within the acceptance criteria contained in the procedure. The inspectors verified that the pump performance data met the requirements of the procedure acceptance criteria.

Within the areas reviewed, violations or deviations were not identified. A significant maintenance weakness was identified due to the failure to perform preventive maintenance on torque switch contacts for Limitorque motor operated valves.

4. Review of Oconee Overtime

The inspectors reviewed documentation for overtime worked at the Oconee Nuclear Station during the previous year. This included the Oconee Nuclear Site Directive 3.3.1, Overtime Control, and an audit by the licensee of that program. The following is a summary of that review.

The directive requires Station Manager/Designee approval for all overtime that is worked in excess of the work hour guidelines of TS 6.4.3. The guidelines are as follows:

a. Working more than 16 hours consecutively (excluding shift turnover time).
b. Working more than 16 hours in any 24 hour period (excluding shift turnover time).
c. Working more than 24 hours in any 48 hour period (excluding shift turnover time).

d. Working more than 72 hours in any 7 day period (excluding shift turnover time).
e. Less than 8 hour break between scheduled work periods (excluding call-outs, but including shift turnover time).

A review of the required approvals for exceeding the limits as specified above are identified below for each of the categories (a, b, c, & d) as follows:

Category	1993										1994	
	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Jan	Feb
a.	-	-	-	3	-	2	4	-	4	-	8	1
b.	-	2	8	8	-	5	-	3	-	-	3	2
c.	-	2	-	2	-	7	-	2	1	5	27	14
d.	-	-	221	38	-	-	2	3	-	-	291	278

The following is a compilation of the overtime expended at the Oconee Nuclear Plant during the previous year (March 1993 through February 1994). This time frame was of particular interest since two refueling outages are included (i.e., Unit 2 during May - June of 1993 and Unit 3 during January - February of 1994). The overtime profile listed below is an average of 8 months during times when there was essentially no refueling in progress (Non-Outage) and 4 months that the plant was in a refueling outage (Outage).

DISCIPLINE	NO. OF EMPLOYEES	MONTHLY OVERTIME AVERAGE NON-OUTAGE	OUTAGE
Mechanical, I&E, & Maintenance	433	2,345	13,240
Radiation Protection	82	644	1,421
Operations	202	2,330	5,318

The inspectors determined that the licensee was in compliance with the Oconee directive. However, the directive does not limit the amount of overtime that can be approved. Although TS requires the licensee to have a program in place to limit the amount of overtime, there is no absolute limit imposed.

5. Inspection of Open Items (92701) (92702)

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

- (Closed) Escalated Enforcement Item 269,270,287/92-24-02: Low Flow Through 3B Low Pressure Injection Cooler.

  This escalated enforcement action was issued for failure to adequately address a low service water flow condition through low pressure injection cooler 3B during the performance of a surveillance procedure. During the performance of the surveillance the licensee had to start an additional low pressure service water pump to obtain the required flow rate through the low pressure injection cooler. During subsequent flow testing the licensee determined that a cooler outlet valve was not fully open due to a valve operator failure.

This item was addressed in NRC Inspection Report 269,270,287/92-24. An enforcement conference was held November 24, 1992, in the NRC Region II office to discuss the violation, its cause, and corrective actions to prevent recurrence. The inspectors reviewed the licensee response to the violation and corrective actions. Based on these reviews, this item is closed.

6. 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 are closed:

a. (Closed) LER 287/92-03, Reactor Trip Results From A Momentary Loss Of Integrated Control System (ICS) Power Due To Manufacturing Deficiency And Design Deficiency

On June 24, 1992, while operating at approximately 100 percent power, Oconee Unit 3 tripped as a result of a momentary loss of the ICS power from power panel board 3KI. The loss of power to panel board 3KI resulted in a trip of both main feedwater pumps and the main turbine (per design). The reactor was automatically tripped via the anticipatory reactor trip. The momentary loss of ICS power resulted from closing a breaker (3KI-15) which supplied an inadvertently grounded LPSW pressure indicator which caused the ICS inverter's internal static transfer switch to transfer to its alternate power source. The 80 amp fuse in the static transfer switch associated with the inverter's alternate power source subsequently blew, causing a total loss of power to panel board 3KI. The subsequent loss of power to the steam generator level instruments resulted in a false high steam generator level indication which caused the trip. Power to panel board 3KI was automatically restored approximately 0.5 seconds later when the backup transfer switch swapped over to its emergency power supply.

The inadvertently grounded LPSW pressure indicator was the result of Instrument and Electrical (I&E) Technicians wiring the power supply pin to chassis ground. The pressure indicator had just been replaced as part of Nuclear Station Modification (NSM) 32590. The licensee determined that the indicator was wired in accordance with the NSM design drawings provided to the I&E technicians, and that these drawings were based upon a version of the manufacturer's instruction manual. However, upon review of the manufacturer's instruction manual (OM-333-379), the licensee discovered that the instruction manual contained three different versions and the NSM design drawings were based on a version of the instruction manual for a different style of indicator than that utilized for the NSM.

The short-term corrective actions for this event included postponing the modification until the next Unit 3 refueling outage, and replacing the blown fuse in the 3KI inverter. The long-term corrective actions included an engineering analysis of why the fuse blew in the inverter, reviews of other modifications involving Dixson indicators, and training of appropriate engineering personnel to ensure the correct version of vendor manuals are used for design drawings.

The inspector reviewed the engineering analysis of the fuse failure documented under PIP 0-092-0485. The PIP concluded that there was a coordination problem between the 80 amp fuse within the inverter and a 60 amp fuse within the branch circuit associated with breaker 3KI-15. The coordination problem was due to the fact that the 80 amp fuse internal to the inverter is a form 101 semi-conductor fuse which is much faster than the 60 amp class G fuse in the breaker circuit. The licensee had already made plans to replace the inverters under an existing NSM. The new inverters will be of a different design which does not involve a fuse, thereby eliminating the coordination problem. The inspector noted that the PIP stated that the implementation of the NSMs to replace the inverters was to begin in 1993, while no inverter replacements had been accomplished as of April 1994. The licensee stated that 1993 was only a target date for inverter replacement and should not have been construed as a commitment to the NRC.

The inspector reviewed the training material provided to engineering personnel (to ensure the correct version of vendor manuals are used) and found it to be acceptable.

b. (Closed) LER 269/92-01, Management Deficiency Results In Energizing Standby Bus From Unprotected Offsite Power Source Making Accident Mitigating Systems Technically Inoperable.

During an Emergency Power Switching Logic (EPSL) performance test, control room personnel energized the standby bus from the Lee Substation rather than from the Lee Gas Turbines as required by the procedure. Since the Lee Substation does not have relay protection per the design requirements for an offsite power supply, the standby bus was not protected from potential undervoltage conditions on the grid for approximately one hour.

A Severity Level IV violation was issued for failure to follow procedures in NRC inspection report 269,270,287/92-03. Corrective actions for the violation were inspected and the violation was closed in NRC inspection report 269,270,287/92-30. Corrective actions for the LER included revising the relevant procedure and adding training on procedure compliance to the operator requalification program. The inspector confirmed that the procedure revisions were made and that the training course changes had been implemented.

c. (Closed) LER 269/92-10, Design Deficiency Results In Technical Inoperability of Oconee Emergency Electrical Power Sources.

On February 19, 1992, the licensee determined that due to the presence of a discriminator feature in a Westinghouse circuit breaker equipped with Amptector solid state trip devices, breaker coordination did not exist during certain situations. Specifically, during a postulated Loss of Coolant Accident (LOCA) coincident with a loss of off-site power, a fault on a non-safety load could trip the upstream Keowee Auxiliary load center power breaker. This would result in removing power from essential safety-related auxiliary equipment for the affected Keowee unit.

A discriminator circuit will cause a breaker to trip instantaneously if no current is flowing through the breaker when a fault develops downstream. The feature is designed to clear a fault when a breaker closes in on a pre-existing fault. This occurs even if the breaker is not equipped with an instantaneous trip. The breaker coordination scheme for the breakers in question had not considered that an instantaneous trip could occur, which would preempt both the slow trip and rapid trip features of the breaker. The design deficiency was identified during an Operating Experience Review of a Westinghouse service bulletin notifying customers of the problem.

The discriminator circuit was disabled on the affected breakers on August 20, 1992. The bulletin was added to the vendor manual June 8, 1993. The inspector reviewed the implementation of the modification and verified that the vendor manual had been revised.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on May 3, 1994, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings addressed 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
50-270/94-11-01	Inspector Followup Item: Slow Transfer of the "E" Breakers (paragraph 2.c).
50-287/94-11-02	Inspector Followup Item: Torque Switch Maintenance (paragraph 3.a).