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

Report Nos.: 50-269/90-04, 50-270/90-04, 50-287/90-04

Licensee: Duke Power Company
422 South Church Street
Charlotte, N.C. 28242

Docket Nos.: 50-269, 50-270, 50-287 License Nos. DPR-38, DPR-47, DPR-55

Facility Name: Oconee Nuclear Station Units 1, 2, and 3

Inspection Conducted: January 14 - February 17, 1990

Inspectors: [signature] for 2/28/90
P. H. Skinner, Senior Resident Inspector — Date Signed

[signature] for 2/28/90
L. D. Wert, Resident Inspector — Date Signed

[signature] for 2/28/90
B. B. Desai, Resident Inspector — Date Signed

Approved by: [signature] 2-28-90
M. B. Shymlock, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations, surveillance testing, maintenance activities, evaluation of licensee self-assessment capability, observation of fitness for duty training and inspection of open items.

Results: In addition to the routine inspection activities, the residents reviewed the licensee's actions concerning;

- A Unit 3 reactor trip which occurred during routine testing of the Control Rod Drive system (paragraph 2.b.).

- The identification and subsequent repairs of a body-to-bonnet leak on valve 3LP-9 (paragraph 3.b.).

- The resolution of a potential problem with Sylvania circuit breaker loose contactor screws (paragraph 2.c.).

No significant weaknesses were noted.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *B. Barron, Station Manager
   D. Couch, Keowee Hydrostation Manager
   *J. Davis, Technical Services Superintendent
   D. Deatherage, Operations Support Manager
   B. Dolan, Design Engineering Manager, Oconee Site Office
   *W. Foster, Maintenance Superintendent
   *R. Gill, Manager Regulatory Compliance
   T. Glenn, Instrument and Electrical Support Engineer
   D. Hubbard, Performance Engineer
   *C. Jennings, Station Emergency Planner
   *E. LeGette, Compliance Engineer
   H. Lowery, Chairman, Oconee Safety Review Group
   B. Millsap, Maintenance Engineer
   D. Powell, Station Services Superintendent
   *G. Rothenberger, Integrated Scheduling Superintendent
   *R. Sweigart, Operations Superintendent

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

   NRC Resident Inspectors:

   *P. Skinner
   *L. Wert
   B. Desai

   *Attended exit interview.

2. Plant Operations (71707)(71710)

   a. 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, and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & electrical (I&E), and performance personnel.

      Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Some inspections were made during shift change in order 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. The areas toured included the following:

Turbine Building
Auxiliary Building
CCW Intake Structure
Independent Spent Fuel Storage Facility
Units 1, 2 and 3 Electrical Equipment Rooms
Units 1, 2 and 3 Cable Spreading Rooms
Units 1, 2 and 3 Penetration Rooms
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Units 1, 2 and 3 Spent Fuel Pool Rooms
Keowee Hydro Station

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

Units 1 and 2 operated at 100% power for the duration of this reporting period.

Unit 3 commenced this report period operating at 100% power and continued operation at that level until January 19 when a reactor trip occurred (see paragraph 2.b). The unit returned to 100% on January 21 and operated at that level for the remainder of the period with the exception of a one day period at 95% to repair a leaking valve on the second stage reheater.

b. Unit 3 Reactor Trip

At 8:49 a.m. on January 19, 1990, Unit 3 experienced an automatic reactor trip. The automatic trip was caused by a low Reactor Coolant System (RCS) pressure condition. I&E personnel were performing Instrumentation Procedure (IP) 0/B/340/02, Control Rod Drive (CRD) DC Hold Supply, Regulate Supply SCR Gate Drive, and Programmer Checks when the trip occurred. Post trip response was normal with the following exceptions:

- The 'B' Once Through Steam Generator (OTSG) level control did not properly control the level in the 3B OTSG resulting in a higher than normal level following the trip.

- The 'B' Main Feedwater Control Valve would not stay in the manual mode as selected by the operator.

- The 'A' Main Feedwater Pump (MFWP) tripped on high discharge pressure.

A review conducted by the licensee identified the following sequence of events:

- IP/0/B/340/02 was being conducted by I&E. Due to a problem in the rod drive control system all rods in Group 6 were unlatched and dropped into the core.

- For the conduct of the IP, the Integrated Control System (ICS) had been placed in the manual mode as required by normal procedures. This precluded the ICS from automatically running the feedwater control systems back following the trip.

- When the Group 6 rods dropped, the continued feedwater flow to the OTSGs resulted in a rapid RCS pressure decrease which caused an automatic RCS low pressure trip at 1800 psig.

- The operators immediately attempted to take manual control of the main feedwater valves in order to reduce feedwater flow. The 'B' OTSG feedwater valve did not immediately shift to manual control when the operator attempted to perform the transfer. Several attempts had to be made before the valve was successfully shifted to the manual control mode.

- The 'B' OTSG level control circuit of the ICS apparently attempted to control level at a higher value than the 25 inch programmed level setpoint following a trip.

- Other problems that occurred were: (1) a relief valve on the 'C2' feedwater heater failed open which resulted in the heater requiring isolation, and (2) Condensate Booster Pump (CBP) 'A' experienced a mechanical seal failure.

The licensee conducted an investigation of the trip and events that occurred as part of this trip. The findings were discussed in detail with the inspectors. The inspectors witnessed actions taken by the operators and portions of the corrective actions taken by the licensee. The inspectors participated in the post trip meeting held on January 26, 1990. Corrective actions were taken for each specific problem identified prior to returning the unit to power operation. The licensee notified the NRC as required by 10 CFR 50.72(b)(2)(ii).

The licensee's investigation resulted in the following actions:

- The problem with the CRD system was attributed to either an operator error (the "clamp release" pushbutton was not fully actuated) or a failure in the clamp circuit which could not be duplicated. This action allowed both the auxiliary and the normal power supply voltage to be simultaneously applied to the mechanisms in group six. When the I&E technicians, in accordance with the procedure, cycled the normal power supply to the various phases of the control rod group six contactors, four phases were simultaneously energized in an alignment which resulted in a cancelling effect on the CRD magnetic fields. This caused the rods to unlatch and drop. Procedures are being changed to monitor for phase relationships when performance of this IP is being conducted. Further review of this is being pursued by the licensee.

- The problem identified with the OTSG level control on the B generator was determined to be an improper setpoint on an integral module in the ICS feedwater controller. The setting was returned to the correct position and an investigation is being performed to determine how the setpoint was misadjusted.

- The problem identified with the MFW control valves was determined to be an incorrect module installed in the ICS system. Although the modules in question have the same supply system identification number, the modules are designated F (correct) and G (incorrect) on their labels. The time delay associated with the G module is longer and required the switch for the MFW valve to be held in position a longer period to initiate a transfer to manual. Since this was not known by the operators, difficulty was experienced in making this transfer. The licensee is investigating this problem to determine how this incorrect module was obtained and installed.

- The 'A' MFWP trip occurred due to a problem with setpoint drift associated with the pressure switches involved. On increasing discharge pressure, the 'B' MFWP is expected to trip before the 'A' MFWP. (The setpoints are 1275 and 1240 psig for A and B respectively.) I&E concluded that the change in setpoint was probably due to vibration. A locking material will be used on the setting adjustment screws during subsequent calibrations.

- The relief valve on the C2 heater was attributed to a failure of the valve. It was gagged and a temporary relief was installed on a vent line as temporary corrective action. The relief valve will be repaired during a subsequent shutdown.

- Condensate booster pump 'A' has been isolated and the mechanical seal is being repaired.

Based on the actions taken and a review of Units 1 and 2 to ensure similar problems were not identified on those units, Unit 3 was returned to power operation at 1:47 a.m., January 20 and was returned to 100% power at 6:47 a. m., on January 21.

c. Inspection for Loose Contact Carrier Screws in Sylvania Contactors

On January 17, 1990, the inspectors were informed by the resident inspectors at Catawba Nuclear Station of a potential problem regarding Sylvania circuit breaker contactors. Duke Power Company (DPC) personnel had discovered that the contact carrier screws in several circuit breakers had become loose. The contactors are used inside safety-related (S/R) and nonsafety-related breakers on Motor Control Centers (MCCs) throughout the DPC nuclear stations. The loosening or backing out of these screws can result in the breaker becoming inoperable. Apparently the screws become loose after numerous operations.

The inspectors contacted Oconee Instrument and Electrical personnel when informed of the potential problem. The Catawba initiated Problem Investigation Report (PIR 0-C90-0008) had not yet reached Oconee. It was determined that these contactors are utilized much less at Oconee than the other DPC nuclear stations. The following S/R or important to safety applications of the Sylvania contactors were identified;

- Four S/R remote starter valve breakers per unit; Valves LPSW-565,566 (Low Pressure Service Water to 'B' Reactor Building Cooling Unit and Auxiliary Coolers) and HP-409,410 (High Pressure Injection pump discharge cross connects).

- Eight important to safety valve breakers per unit, two in the reactor building purge system, six in the feedwater system.

- Numerous S/R valve breakers on several MCCs located in the Safe Shutdown Facility (SSF).

Oconee I&E personnel promptly carried out inspection on all of the above breakers to verify no loose screws existed. The inspection consisted of opening the breaker enclosure and performing a visual verification that the screws were flush with the adjoining surface. The inspectors observed most of these inspections conducted on the SSF valve breakers. All inspections were completed on January 17, with no loose screws noted. The majority of those S/R breakers are infrequently cycled. Additionally, these breakers had been installed at Oconee after this potential problem had been noted by the manufacturer and screws coated to prevent this problem were utilized. The inspectors will continue to follow the licensee's actions in regards to both long term corrective actions and final resolution of the PIR. Regional Management is following this issue for potential generic implications.

No violations or deviations were identified.

3. Surveillance Testing (61726)

a. 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 tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

Surveillances reviewed and witnessed in whole or in part:

PT/1/A/0150/22A	Operational/Refueling Valve Functional Test dated January 11, 1989
PT/0/A/0160/02	RB Cooling System Performance Test dated January 9, 1989
PT/0/A/0160/03	RB Cooling System ES Test dated January 8, 1989
IP/0/A/0310/014C	Engineered Safeguard System Analog Channel "C" On Line Calibration

b. 3LP-9 Leakage In Excess Of TS Surveillance Limits (71707,61726)

At approximately 5:00 p.m. on January 30, 1990, during maintenance efforts to correct a previously identified body-to-bonnet leak on valve 3LP-9 (Low Pressure Injection (LPI) Pump discharge cross connection valve) it was identified that leakage had increased to approximately 2.2 gallons per hour (gph). TS 4.5.4: Low Pressure Injection System Leakage, requires that at each refueling outage tests to determine LPI system leakage shall be conducted. The requirements specify that the portion of LPI which contains valve 3LP-9 shall be tested either by use in normal operation or hydrostatically tested at 350 psig. The TS acceptance limit states that maximum allowable leakage from the LPI system including valve stems, flanges and seals shall not exceed 2 gph. The 2.2 gph leakage from 3LP-9 was measured with approximately 40 psig present on the system (primarily Borated Water Storage Tank static head).

The issue was promptly reported to the resident inspectors. Discussions were held regarding the available options for repair of the leak and the course of action regarding the LPI system. After attempts to stop or minimize the leak by overtorquing the body-to-bonnet studs had failed, the 'A' LPI train was isolated at 7:24 p.m. This action stopped the leak. Valve 3LP-9 was successfully repaired and the 'A' train of LPI was returned to service within the 24 hour Limiting Condition for Operation period specified for an LPI train out of service in TS 3.3.2.

While the basis and intent for the requirements of Surveillance TS 4.5.4 are not clear, the above actions were conservative and resulted in the rapid isolation and repair of the leak. The licensee has initiated a Problem Investigation Report (PIR) to address questions about TS 4.5.4 which surfaced during this situation. The inspectors will continue to follow the licensees actions.

No violations or deviations were identified.

4. Maintenance Activities (62703)

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

Maintenance reviewed and witnessed in whole or in part:

WR 22911C	Readjust Closing Indication Time On Valve 2LPSW-21 (IP/0/A/3001/10 Maintenance of Limitorque Operators, June 26, 1989)
WR 053790I	Inspection of Contact Carrier Screws In Specific Valve Breakers
WR 26227C	Troubleshoot 2FDW106

No violations or deviations were identified.

5. Evaluation of Licensee Self-Assessment Capability (40500)

The inspectors completed the review of the licensees capability to perform self assessments which was started in November 1989 (See Inspection Report 50-269,270,287/89-36). The Oconee Nuclear Safety Review Board (NSRB) conducted a meeting at the station January 23 and 24, 1990, at which various topics were discussed in detail with representatives of the Oconee operating staff and various support groups. Topics included Emergency Power Switching Logic problems, methods of providing Design Data to the station, security issues, Technical Specification 3.1.2 associated with Low Temperature Overpressure Protection, and various other topics. The NSRB asked indepth questions of the personnel involved and made recommendations to the NSRB Chairman to address outstanding issues.

No violations or deviations were identified.

6. Resident Inspector Observation of Licensee Fitness For Duty Training (TI 2515/104)

On February 12, 1990, the senior resident inspector observed the training being provided to new supervisory staff personnel. The training consisted of a series of video tapes in conjunction with a lecture presentation. The presentation was taken from a training lesson plan entitled FFD-001-FFD, Training For Supervisors. The session lasted approximately three hours and fifteen minutes. Although there were only four individuals in the training, the class actively participated in a question and answer session at the conclusion of the presentation. The concerns expressed by the inspectors at a previous training session concerning training in the areas of behavior observation and escort training were included in this training. This training and the previous training discussed in Inspection Report 50-269,270,287/89-36 fulfills the requirements contained in TI 2515/104.

No violations or deviations were identified.

7. Licensee Quality Assurance Program Implementation (35502)

An internal office evaluation of the licensee's quality assurance program implementation was conducted by reviewing recent inspection reports, SALP reports, open items, licensee corrective actions for NRC inspection findings and licensee event reports. Particular emphasis was placed on all new items or findings since the last SALP report period. There were no recommendations to perform additional inspections. An evaluation by Emergency Preparedness of a drill in addition to the annual exercise was already planned.

8. Inspection of Open Items (92700)(90712)(92701)

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

a. (Closed) IFI 269,270,287/89-12-01: Resolution of Malfunctions Associated With RVLIS. This item was identified due to a variety of faults that could be received on the reactor vessel level instrumentation system (RVLIS) that would cause the indicators to display the word "Malfunction". Operators could not determine if the system was operable if this condition occurred. As a result the licensee issued a surveillance procedure which was conducted two times a day by operations personnel to determine operability. Nuclear Station Modification (NSM) 2401 has been developed and implemented on Unit 3 which provides malfunction in the form of an annunciator alarm. Upon receipt of this annunciator alarm I&E technicians make a determination as to the operability of this system. If a failed sensor occurs and can be bypassed without effecting the RVLIS operability, this will be done by I&E and the malfunction indication will be eliminated returning the system to normal indication for operator use. This NSM is scheduled to be accomplished on Units 1 and 2 during the next refueling outage. Based on this action, this item is closed.

b. (Closed) IFI 269,270,287/88-12-03: Management Review of Communications Interface Between Performance and Operations During Testing. This item addressed a concern that operating requirements of a performance test were not communicated to Operations personnel conducting the test. Training sessions emphasizing the responsibilities of Operations personnel during the specific performance test (Turbine Driven Emergency Feedwater Pump Performance Test) were conducted with all non-licensed operators (NLOs) on all shifts. Additionally a specific Limit and Precaution' statement in the Performance Test was modified to more clearly state the responsibilities of the NLO during testing. Operations management sent a letter to various station Section Heads addressing the communications interface between Operations and other working groups during testing or maintenance. The inspectors have observed improvement in these interfaces since this issue was identified. Communications between Operations and other working groups during testing have not been a problem in recent months. Communications between Instrument and Electrical technicians and operator's involving a performance test during which a Unit 3 trip occurred (paragraph 2.b) were noted as particularly strong. This item is closed.

c. (Closed) LER 50-269/89-07: Release To Chemical Treatment Pond Results In A Condition Prohibited By Technical Specifications. This LER was addressed in Inspection Report 50-269,270,287/89-25. This item was left open pending management review of staffing requirements of the radwaste facility. Discussions with the Technical Superintendent identified that portions of the facility will not be operated and based on that decision the present staffing levels are adequate. Based on this discussion, this item is closed.

d. (Open) LER 287/88-03: Potential Degraded Performance of Reactor Building Cooling Units (RBCUs) Due to Service Induced Fouling. This LER addressed a situation in which performance testing data indicated that service induced fouling of the Unit 3 RBCUs may have reduced their post-LOCA heat removal capabilities below acceptable limits. The inspectors have been closely following the licensees actions to resolve this issue. Inspection Reports 50-269,270,287/89-11 and 28 contain additional details. Currently, the licensee is still performing testing at quarterly intervals on each of the three units. The service induced fouling of the coolers has been attributed to an air side fouling problem but the exact phenomenon has not been confirmed. The licensee has purchased improved instrumentation to obtain humidity and air temperature values during testing. The instrumentation will be permanently installed inside the RBCU ductwork. There continues to be uncertainty in the correlation of data obtained during "cold" (approximately 100 degrees F) or on-line testing to the predicted cooler performance under LOCA conditions.

Data obtained during testing performed just prior to shutdown of Unit 3 for its end of cycle (EOC) 11 refueling outage indicates that the analysis may still be overly conservative when predicting LOCA heat transfer capabilities from on-line data. Because of a problem with the Reactor Building Auxiliary Coolers, (see Inspection Report 50-269,270,287/89-34), Unit 3 containment temperatures were higher than normal during the EOC testing (approximately 125 degrees F). The coolers heat removal capabilities for LOCA conditions were calculated at values of about 100 percent of their design parameters based on this data. Testing after extensive cooler cleaning (prior to plant startup), conducted under cooler ambient conditions, yielded values of only seventy percent.

While all of the planned corrective actions listed in the LER have been completed, the licensees actions to fully resolve the fouling mechanism and any overly conservative considerations in the calculated LOCA capabilities of the coolers are continuing. This item remains open.

e. (Closed) 10 CFR 21: Potential Deviation To Specifications In RY Vertical Indicators, Series 15, All Versions of RY 1 and RY 2 (P2188-05). This Part 21 was identified to the NRC in correspondence dated October 10, 1988. The licensee has replaced all safety-related Bailey RY indicators, with the exception of one indicator in each unit, with a new design manufactured by Dixon. The remaining indicator is located in each control room and indicates High Pressure Injection crossconnect flow. There are no plans by the licensee at this time to replace this indicator. The licensee considers that since the problem identified by the Part 21 is associated with a change in temperature of 60 degrees, that since the indicator is located in the control room, the problem identified will not be observed in this instrument. Based on this information this item is closed.

9. Exit Interview (30703)

The inspection scope and findings were summarized on February 16, 1990, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.