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

Report Nos: 50-269/87-13, 50-270/87-13, and 50-287/87-13

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

Facility Name: Oconee Nuclear Station

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

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

Inspection Conducted: March 10 - May 11, 1987

Inspectors: J.C. Bryant — 5/22/87 Date Signed

L.D. Wert — 5/22/87 Date Signed

Approved by: T.A. Peebles, Section Chief, Division of Reactor Projects — 5/22/87 Date Signed

SUMMARY

Scope: This routine, unannounced inspection involved on-site resident inspection in the areas of operations, surveillance, lineups, followup of events, cleaning and testing of reactor building cooling units and decay heat removal coolers, and shutdown work in progress. Additional areas examined during the report period are described in Report No. 50-269,270,287/87-16.

Results: No violations or deviations were identified in the areas covered in this report.

REPORT DETAILS

1. Licensee Employees Contacted

*M.S. Tuckman, Station Manager
T.B. Owen, Maintenance Superintendent
R.L. Sweigart, Operations Superintendent
J.M. Davis, Technical Services Superintendent
*C.L. Harlin, Compliance Engineer
*F.E. Owens, Assistant Engineer, Compliance
L.V. Wilkie, Superintendent of Integrated Scheduling

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

Resident Inspectors:

*J.C. Bryant
L.D. Wert

*Attended exit interview.

2. Exit Interview

The inspection scope and findings were summarized on May 12, 1987, with those persons indicated in paragraph 1 above.

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Enforcement Matters

(Closed) Violation 50-269,270,287/86-33-02: Inadequate Testing of ECCW System. This item was discussed in Report No. 87-10. Corrective action and response have been completed.

4. Unresolved Items

No unresolved items were identified during this inspection.

5. Plant Operations

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. Interviews were conducted with plant operations, maintenance, chemistry, health physics 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 week days and on weekends. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by Operations Management Procedure 2-1. 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
Units 1,2, and 3 Electrical Equipment Rooms
Units 1,2, and 3 Cable Spreading Rooms
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Unit 3 Containment Building

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

Unit 1 ran at 88% power throughout the report period, limited by the temporary main stepup transformer installed in early March.

Unit 2 began the report period at 96% power, as limited by steam generator level, and continued at that level until March 26 when it tripped on RCS high pressure as a result of a feedwater transient. Reactor trips are discussed in paragraph 8 of this report. The unit was returned to 96% power on March 28 and continued at that power until April 7, when power was reduced due to degraded heat transfer in reactor building cooling units (RBCU's) and decay heat removal (DHR) coolers (See paragraph 12). The reactor was returned to 88% power (as limited by high steam generator level) on April 12, where it remained until April 20, when it tripped on high steam generator level. Unit 2 reached 88% power again on April 21, and continued at that power until the end of the report period.

Unit 3 began the report period in refueling shutdown. The unit was placed on line at 15-20% power on March 31, for a brief period to test the main generator which had been rebuilt during the refueling shutdown. The reactor was then taken to hot shutdown for testing of RBCU's and DHR coolers (Paragraph 12) and then to cold shutdown to repair a leak on the RVLIS system. Subsequent to repairs, as Unit 3 was being heated for RBCU testing and startup, procedures were violated concerning the HPI system and RBCU's. Theses events are discussed in detail in Report No. 50-269, 270,287/87-16, and will not be discussed in this report. After startup on April 14, the unit was taken off line on April 15, to replace a bad phase pot fuse and to balance turbine bearings, then reached 60% power on

April 16 and 100% power on the 17th. The unit was taken off line on April 23, to repair a steam generator tube leak and was again taken critical on May 2 (Paragraph 13). Unit 3 operated at 100% power for the remainder of the report period.

No violations or deviations were identified.

6. Surveillance Testing

The surveillance tests listed below were reviewed by the inspector 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 witnessed in whole or in part:

PT/0/A/0150/08A	RB Personnel Lock Leak Rate Test
MP/0/A/1705/27	Fire Protection, Repair of Electrical Penetration
IP/1/A/305/3	Reactor Protection System, Channel D Calibration and Functional Test.
IP/0/A/360/2	3R1A-54 Turbine Building Sump Radiation Monitor Calibration

Completed surveillance reviewed:

W/R 05900C Unit 1 TDEFWP Bearing Oil Cooling Pump

No violations or deviations were identified.

7. Maintenance Activities

Maintenance activities were observed throughout the report period but were limited to spot checks of maintenane personnel, appropriate procedures and work performance. Some of the activities observed were rework of Unit 3 main feedwater valves, rework of Limitorque operators, auxiliary boiler inspection, repair of a fireproof penetration, rework of RCW "B" Pump.

No violations or deviations were identified.

8. Unit 2 Trips

On March 26, 1987, at 11:33 p.m., Unit 2 tripped from 96% power on high reactor coolant system (RCS) pressure. Cause of the event appeared to be an intermittent, poor connection in the Integrated Control System (ICS) BTU limit circuitry. The specific portion of the ICS affected was the steam generator feedwater control. As a result of the electrical failure, feedwater (FDW) demand went to near zero on "A" steam generator (SG). The ICS responded by reducing flow to "A" SG, resulting in increased RCS temperature and pressure and the reactor trip. Circuitry repairs were made and the reactor started up and placed on line at 12:00 noon on March 28.

On April 20, 1987, at 5:33 a.m., Unit 2 tripped from 86% power when FDW demand on the A loop went low. The ICS responded by decreasing flow to "A" SG and increasing flow to "B" SG. Since "B" SG level was already at about 89%, the level quickly reached 96%, tripping FDW pumps and the turbine. The reactor then tripped on the turbine anticipatory trip.

Investigation revealed that a failed multiplier module in the BTU limit circuitry had caused the problem. The module was replaced and the unit taken critical at 5:15 p.m. on April 20.

There have been other trips in the past caused by failures in the BTU limit circuitry. The primary purpose of the BTU limit circuitry, as stated by the licensee, is to maintain steam quality for protection of the turbine at low power levels. Unit 3 was shut down at the time of the Unit 2 trip, and prior to startup of Unit 3 a modification was installed which will remove the BTU limit circuitry signal at power levels above 25%. This modification later was installed on Unit 2 with the unit on line, and it will be installed on Unit 1 while it is on line.

No violations or deviations were identified.

9. Unusual Events Due to Non-isolable Leaks, Units 2 and 3

An Unusual Event was declared at 3:31 p.m. on March 31, when an unisolable leak of less than 1 gpm was discovered in the Unit 3 reactor coolant system (RCS) at a pipe to coupling weld in the RVLIS system. At the time, Unit 3 was at hot shutdown. The RCS was reduced to cold shutdown conditions under the assumption that the reactor would have to be defueled and drained to repair the leak. The Unusual Event was terminated when the RCS reached cold shutdown conditions. At this point the licensee determined that the leak, which had been reduced to weeping, could be repaired "wet" by stick welding the leak closed then making a TIG overlay on the pipe.

The weld procedures to be used were discussed with the resident inspector and then, by telephone, with welding engineers in Region II. The pipe was then successfully repaired and stiffeners added to the pipe to prevent recurrence.

On April 8, 1987, a leak of 0.3 gpm at an almost identical location was discovered on Unit 2 while the RCS was at 240 degrees F and 185 psig. An Unusual Event was declared. The same repair methods were used as on Unit 3 and the cause was the same. Therefore, causes of the event will be discussed as one. An entry was made into Unit 1 containment with the reactor at power to search for similar leaks, but none were found.

The RVLIS instrumentation lines were attached as follows. The low pressure injection (LPI) pump suction drop lines from the RPS are 2500 psig lines. A half couplant was welded to the drop lines and a 3/4" schedule 160 pipe was socket welded into the half couplant. At the end of the 3/4" pipe was an isolation valve where the piping was reduced to instrument tubing to a supported level transmitter. The leaks were in the heat affected zone of the socket weld. The crack on Unit 3 propagated circumferentially about 180 degrees around the pipe.

The RVLIS modification was made on Unit 1 (which had no failure), during a refueling outage which began February 13, 1986. The pipe drawings used for fabrication of the pipe showed full pipe diameters. It showed the isolation valve at the end of the 3/4" pipe 12 inches from the centerline of the 12" LPI drop line. The modification for Unit 1 was fabricated in that manner.

In early 1986, Duke Design Engineering changed the type drawings to one line computerized isometrics showing only the centerline on the drawings. Reportedly, no training concerning this change was given to personnel associated with implementation of modifications at Oconee. Consequently, the piping for Units 2 and 3 was fabricated with the isolation valve 12", from the 12" pipe wall rather than from the centerline. Proper installation would have resulted in the valve being 6" from the pipe wall. The QA inspectors also misread the drawings.

The prefabricated piping was welded into the Unit 2 LPI line on September 11, 1986, and Unit 2 was in operation from October 15, 1986, until the failure was detected on April 8, 1987. The piping was welded into the Unit 3 LPI line on January 27, 1987, during refueling outage. The weld was visually inspected by Maintenance, during heatup, on March 28, 1987. Total unit operation under nuclear heat, at a maxim power level of 20%, was only about one day.

Duke Power Company investigators determined that failure was due to weakening of the pipe wall by stress induced by natural frequency vibration. This was caused by the extra length of pipe putting the pipe section outside the seismic stress design basis.

It appears that work and inspection were done correctly except for the lack of understanding of the new drawing system. This appears to be another example of inadequate communication between Design Emgineering and plant personnel. Currently, there is a violation open on the same subject

in the same time frame as described in Report No. 50-269,270,287/86-16. That violation concerned inadequate communication concerning installation of Keowee batteries. The matter of communications concerning drawing changes will be considered as another example of the referenced violation.

10. Resident Inspector Safeguards Inspection

In the course of the monthly activities, the Resident Inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities which included: protected and vital area access controls, searching of personnel, packages and vehicles, badge issuance and retrieval, escorting of visitors, patrols and compensatory posts. In addition, the Resident Inspectors observed protected area lighting, protected and vital area barrier integrity and verified interface between the security organization and operations and maintenance. The Resident Inspectors also witnessed spent fuel shipment and visited central and secondary alarm stations.

11. Information Notice 87-19: Perforation and Cracking of Rod Cluster Control Assemblies

The referenced notice concerns perforation and cracking of Westinghouse control rod assemblies. Since Westinghouse assemblies in which problems were detected are about the same age as those at Oconee, the inspectors made inquiries and reviewed documentation to determine control rod assembly conditions at Oconee.

Control rod assemblies at Oconee are inspected periodically during refueling outages and a schedule of routine partial replacement of assemblies is in place which will replace all rods over a 10 - 12 year interval. Due primarily to significant differences in construction, Babcock and Wilcox assemblies do not appear to be subject to the fretting and wear of the Westinghouse assemblies. The major factors in this case are the long "C" and "Split" guide tubes of the B&W assemblies which guide the rod fingers when withdrawn. The Westinghouse assemblies do not use such long rod guides. The problems of wear and fretting of rods due to flow-induced vibration have not been observed at Oconee.

12. Reduced Efficiency of Reactor Building Cooling Units and Decay Heat Removal Coolers

During the report period, the licensee determined that heat transfer capability of reactor building cooling units (RBCUs) and decay heat removal (DHR) coolers had fallen below design requirements. For power operation, Technical Specifications (TS) require two independent trains of low pressure injection, including the DHR coolers, be completely operable and that three independent trains of reactor building cooling, including the RBCU's, be completely operable. The above requirements allow some relief for maintenance.

Extensive cleaning and testing was carried out by the licensee and a Confirmatory Order was issued by NRC. A Region II inspection team examined data and history to determine if the licensee had knowingly operated outside of requirements. The team findings and a description of events, and data, will be provided in Report No. 50-269,270,287/87-17; therefore, the resident inspectors' report will deal primarily with operational aspects during the report period.

The first indication of reduced heat transfer capacity of DHR coolers was observed in 1985 when the licensee noted that a Unit 1 cooler seemed to take longer than usual to cool down the RCS. During 1986 the licensee had considerable communication with the RBCU vendor in an attempt to evaluate test data. Some RBCU and DHR cooler cleaning was performed and the method of evaluation available indicated that performance was satisfactory. A section of report no. 50-269,270,287/86-20 discusses an inspection of bio-fouling and states that no significant degradation had occurred due to the cleanliness of Lake Keowee water, which is used in the low pressure service water (LPSW) system (the cooling water supply to the coolers). It also discusses the licensee's method of determining flow degradation.

In 1986, the licensee continued cleaning and testing of coolers and issued a contract to a consultant to develop state of the art formulas for determining heat transfer under plant conditions. The computer program was received from the consultant on March 30, 1987. On March 31, Duke Power Company (DPC) notified NRC that full power operations could not be supported for Unit 3, which was in refueling shutdown at the time, due to inadequate decay heat removal capability.

After completion of operability evaluations for Units 1 and 2, on April 1, DPC notified NRC that full power operation could not be supported for Units 1 and 2. The licensee determined that heat removal capabilities would permit operation of Unit 1 at power levels below 91 %. Unit 1 was then operating at 88% power as limited by the main stepup transformer in use. DPC also determined that Unit 2 operation below 66% power was acceptable. At the time, Unit 2 was operating at 97%; power was then reduced to 60%.

On April 6 DPC issued a request to NRC for an amendment to the operating license permitting continued operations with reduced maximum power trip set points. The request specified increasing LPSW flow through DHR coolers from 3000 gpm to 5000 gpm during certain accident conditions to assure adequate cooling. NRC responded with a letter on April 7 acknowledging the verbal temporary waiver of compliance extended on April 3. The temporary waiver was later extended until 5:00 p.m. on April 10. On April 10, the NRC issued a Confirmatory Order placing restrictions of operation on all three units until all RBCU's and DHR coolers had been verified to meet design requirements.

As described in Report 87-17, all three units underwent cleaning, and in the cases of Units 2 and 3, all coolers were tested. Unit 2 was shut down for cleaning and testing. Unit 3 coolers were cleaned during shutdown, then the unit was shut down again for additional cleaning and testing. Unit 1, which had already been tested, had one DHR cooler cleaned but not tested while the reactor was on line. The Confirmatory Order of April 10 dealt with those coolers which had not yet passed inspection for full power operation at the time of the order.

In brief, the order placed the following conditions for operation of the separate units.

> Unit 1: Until the 1A LPI (DHR) cooler is cleaned, tested, evaluated and approved for full power operation, the maximum power shall be 91.5% of rated power with the high flux trip point set at that power, and the remaining non-ES LPI pump shall be operable. Also Oconee 1 shall not operate at any power level following the cycle 10 refueling outage unless the Regional Administrator, Region II, has approved the 1A LPI cooler for full power operation.
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> Unit 2: Until the 2A LPI cooler is cleaned, tested, evaluated and approved for full power operation by the Regional Administrator, Region II, the maximum power level shall be 81.7% rated power with the high flux trip point set at that level. Should lake cooling water rise above 55°F the unit shall be shut down. The remaining non-ES LPI pump shall be operable.
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> Unit 3: Oconee Unit 3 shall not operate at any power level after midnight of April 22, 1987, unless the Regional Administrator, Region II, has approved full power operation.

On April 13, 1987, and until the end of the report period, the status of the Oconee units was as follows:

> Unit 1: As verified by NRC inspectors, Unit 1 is operating under the above restrictions. (The unit is currently limited to approximately 88% power by the temporary main step-up transformer in use.) The Confirmatory Order conditions remain in effect.
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> Unit 2: On April 11, NRC inspectors reviewed test results and analyses on Unit 2 LPI coolers and reactor building cooling units and found that they met conditions of the Confirmatory Order. The required approval for power ascension to 100% was given by Region II to the station manager at 11:00 a.m. on April 11. (Unit 2 is currently limited to 88% power due to high steam generator levels.)
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> Unit 3: Unit 3 LPI coolers and reactor building cooling units were cleaned and tested. Test results and analyses were reviewed by NRC inspectors on April 12, and found to satisfy the requirements of the

order. The required approval for startup was given by Region II to the station manager at 2:00 p.m. on April 12.

The resident inspectors will continue followup of any developments concerning the cooling units.

13. Unit Three Steam Generator Tube Leak

Unit Three was shut down on April 23, to repair a primary to secondary leak in the A steam generator. The leak was approximately 0.1 gallons per minute. A total of eight steam generator tubes were plugged and the unit was returned to service on May 2, 1987.

No violations or deviations were identified.

14. Inadequate Overpressure Protection for Auxiliary Steam Header

During followup reviews of the Safety System Functional Inspection (SSFI) concerns on undersized relief valves, the licensee discovered a potential failure of the Turbine Driven Emergency Feedwater Pump due to possible overpressurization of the Auxiliary Steam System. This was reported to the NRC operations duty officer on February 27, 1987. Analysis of safety valves on steam lines to the Emergency Feedwater Pump Turbine revealed that if control valves MS-126 (6 in. steam to auxiliary steam) and MS-129 (2 in. main steam to auxiliary steam) fail open, overpressurization of the auxiliary steam system and the Emergency Feedwater Pump Turbine could occur. The potential overpressure situation is due to the undersizing of the auxiliary steam header safety valves (AS-23) and is the subject of LER 269/87-03 of March 30, 1987.

LER 269/87-03 detailed corrective action steps taken as an interim measure until permanent corrective actions were completed. These actions included installation of travel stops on each unit's MS-126 to limit valve stroke, and administrative control of bypass and control valves. These administrative controls are to ensure that: Only one unit is supplying the auxiliary steam header at a given time (other 2 units MS-126 and MS-129 shut); auxiliary steam header section block valves between units are open (ensures a total of 3 sets of 2 relief valves are available); and the manual bypass valves around MS-126 for each unit (MS-131) are shut. These actions will maintain system pressure within applicable code limits and allow sufficient auxiliary steam flow for unit startup.

During the incorporation of these interim measures, an error caused the auxiliary steam header to be supplied from Unit 1 before travel stops were installed on that unit's MS-126. A scaffold had been installed at 1 MS-126 so that the modification could be performed. Through an error, maintenance removed the scaffold without having performed the work, and operations was informed, erroneously, that the job was complete. Unit 1

then supplied the auxiliary header from March 23 to April 21, with some of the administrative controls relaxed due to the misunderstanding. On April 21 the situation was corrected by shifting the auxiliary steam header back to being supplied from Unit 2 which had travel stops installed. Travel stops were then promptly installed on Unit 1 MS-126, completing all the interim corrective actions. Administrative control of the associated steam valves has been closely followed by the resident inspectors.

Operation with Unit 1 supplying auxiliary steam without travel stops installed and with some of the administrative controls relaxed was a violation of a commitment to NRC. However, the licensee identified the error during a routine surveillance, took immediate corrective action, and the situation appears to meet all requirements of 10 CFR Part 2, Appendix C; therefore the event will not be cited as a deviation.

15. Inspection of Open Items

The following open items are being closed based on inspection and/or record review and discussions with licensee personnel as appropriate.

(Closed) LER 50-269/86-09; Keowee Battery Racks Outside of Design Specifications. The immediate problem was corrected within hours of discovery. Satisfactory corrective actions have been taken to correct the underlying cause, communications between Design Engineering and site personnel.

(Closed) UNR 50-269,270,287/86-20-03; Discrepancy in Document/Design Control. Same as LER 86-09 above.

(Closed) LER 50-269/86-11; Inoperability of Emergency Condenser Circulating Water System. This problem was discussed in Reports 86-26 and 86-33. Resolution was satisfactory.

(Closed) LER 50-269/86-14; TS 4.16 Violation-Source Leak Test Not Performed. Corrective action has been reviewed and found acceptable.

(Closed) LER 50-270/86-03; Core Flood Tank Concentration Below T.S. Limit. Problem and corrective action were reviewed and found satisfactory.

(Closed) IFI 50-270/86-26-01; Revisions to the Keowee Load Shed Surveillance Test. Test revisions were reviewed and found satisfactory.

(Closed) IFI 50-270/86-26-02; LPSW Valves to Decay Heat Coolers Did Not Appear to Respond Correctly. Repeated tests have not revealed a discrepancy.

(Closed) LER 50-287/86-01; Reactor Trip From High Reactor Coolant System Pressure. Failure of A1 Feedwater Transmitter. Defective module was identified and replaced.

(Closed) LER 50-287/86-03; Turbine Building Sump Radiation Monitor Found in Bypass Due to a Defective Procedure. Corrective action was reviewed and appears satisfactory.

(Closed) IFI 50-287/85-07-02; Improve Valve LP-2 Operability. Valve operator has been rebuilt and MOVATS tested.

(Closed) Part 21 50-269,270,287/P2184-01; HVAC Equipment Mfg. by Bahnson. In response to IE Information Notice 84-30 the licensee inspected welds in the Bahnson supplied air handling unit in the standby shutdown facility and performed an as-built weld stress calculation. Thirty-eight defective welds were identified, but were eventually determined to be cosmetic in nature. No repairs were required.