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

Report Nos: 50-269/85-41, 50-270/85-41, and 50-287/85-41

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: December 10, 1985 - January 13, 1986

Inspectors: C. W. Burger, for 2/10/86
J. C. Bryant Date Signed

C. W. Burger, for 2/10/86
M. K. Sasser Date Signed

Approved by: Virgil L. Brownlee 2/11/86
V. L. Brownlee, Section Chief, (Acting) Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection entailed 224 inspector-hours on site in the areas of operations, surveillance, maintenance, facility modifications, LER review, and response to the Rancho Seco event.

Results: Of the six areas inspected, no items of noncompliance or deviations were identified in four areas; Two items of noncompliance were found in two areas; Failure to follow exempt change procedure and failure to shut down reactor within 24 hours of discovery of excess leakage.

REPORT DETAILS

1. Licensee Employees Contacted

*M.S. Tuckman, Station Manager
*J.N. Pope, Superintendent of Operations
*T.B. Owen, Superintendent of Maintenance
*R.T. Bond, Compliance Engineer
*T.C. Matthews, Technical Specialist
*R.A. Knoerr, Project Services Engineer
*R.J. Brackett, Senior Quality Assurance Engineer

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

Resident Inspectors

*J. C. Bryant
*M. K. Sasser

*Attended exit interview.

2. Exit Interview

The inspection scope and findings were summarized on January 13, 1986, 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 269, 270, 287/85-20-02 Failure to Report FSAR Revisions as Required. Adequate corrective action has been taken.

4. Unresolved Items

Unresolved items were not identified on 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 Penetration Rooms
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

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

Unit 1 operated at essentially full power throughout the reporting period, December 10, 1985 to January 13, 1986.

Unit 2 operated at full power until December 14 when it was shut down to repair a reactor coolant leak at an instrument root valve. The reactor was returned to power on December 15 and operated at essentially full power through the remainder of the report period. The shutdown is discussed in greater detail in paragraph 8 of this report.

Unit 3 began the report period shut down to replace a main turbine bearing. The unit was returned to power on December 16 and operated at essentially full power the remainder of the report period. The unit startup is discussed in paragraph 11 of this report.

6. Surveillance Testing

The surveillance tests listed below were reviewed and/or witnessed 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 witnessed in whole or in part are as follows:

IP/1/A/305/3C	RPS Channel C On-Line Test
PT/2/A/600/18	Unit 2 Motor Driven Emergency Feedwater Pump Test
IP/1/A/301/3S	Startup & Intermediate Range Channel Test
PT/1/A/0150/22A	Operations Valve Functional Test, Valves BS-1 and BS-2
PT/1/A/251/01	Low Pressure Service Water Pump Test

Surveillance tests reviewed are as follows:

PT/3/A/0150/22A Operational Valve Functional Test, Unit 3.

No violations or deviations were identified.

7. 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 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.

During an inspection of the licensee's program on Motor Operated Valve (MOV) switch setpoints, the inspectors reviewed numerous work requests for Maintenance I&E to troubleshoot and repair MOVs which would not operate from their control room handswitch. In many cases, either Operations or I&E opened the valve from the breaker by depressing the contactor in the breaker compartment, thus bypassing the switches and motor overloads, allowing sufficient torque to be developed for opening the valve.

In a number of the maintenance jobs, the inspectors found that I&E did not use the applicable procedure, did not find the root cause, and did not take adequate corrective action to prevent recurrence. Bypassing motor overloads and switches at the breaker without troubleshooting the problem first was found to be contradictory to the applicable troubleshooting procedure. In all cases reviewed, the maintenance jobs were dated prior to a violation written on the same subject in Report No. 50-287/85-37. That violation concerned inoperability of Valve 3LP2.

The licensee has taken corrective action to upgrade MOV operability as a result of his own studies as well as due to the violation; because of this and the concurrent violation on the same subject, an additional violation will not be cited. The licensee has stated that the appropriate trouble-shooting procedure will be used when performing maintenance on MOV's. Bypassing of torque switches and other controls will not be performed prior to examination to determine root cause, except in cases of operational emergency.

8. Unit 2 Reactor Coolant Leakage

On Friday, December 13, at approximately 1:00 am, the unit 2 reactor coolant system (RCS) leak rate was determined to be 1.32 gallons per minute (gpm). This determination was the result of the daily surveillance of RCS leakage, performed during the 1 hour period from 12 midnight to 1:00 a.m. For a period of approximately 2 weeks the leak rate had been higher than normal, with occasional results above 1 gpm. Subsequent confirmatory results had always proven to be less than 1 gpm. Attempts by the Operations staff to identify and isolate any leakage had been unsuccessful.

However, upon detection of excess leakage on December 13, the subsequent confirmatory results did not prove to be less than 1 gpm. The leak rate calculations were begun on an hourly basis at 1:00 a.m. on Friday, December 13, and new efforts to identify the leak were initiated. Several entries into the reactor building to inspect accessable areas proved unsuccessful. Ten of the eighteen RCS leak rates calculated on Friday indicated unidentified leakage that ranged from 1.02 to 1.65 gpm.

The hourly leak rate calculations were continued on Saturday, December 14. These results also provided evidence of greater than 1 gpm leakage, with ten of eleven surveillances ranging from 1.07 to 1.52 gpm. At approximately 12 noon on Saturday, plant management decided to begin shutdown of unit 2, and at 5:30 p.m., the unit was taken subcritical. While at hot shutdown, a thorough inspection revealed a leaking flow transmitter root valve on the RCS A loop. The leak was repaired and the unit was taken critical on Sunday, December 15 at 2:03 p.m. and power was escalated to 100%.

Technical Specification 3.1.6.2 states that, if unidentified reactor coolant leakage (excluding normal evaporative losses) exceeds 1 gpm ... the reactor shall be shut down within 24 hours of detection. This 24 hour period provides a reasonable period of time to; (1) identify the leak and evaluate its safety significance for continued operation, (2) provide additional sample results to conclusively prove unidentified leakage less than 1 gpm, or (3) shutdown the reactor in an orderly fashion if the first two options are not sucessful.

Contrary to the above, on Friday, December 13, upon detection of RCS leakage in excess of 1 gpm, the leakage was not identified nor proven to be less than 1 gpm. From the time of detection until the reactor was shutdown a period of over 40 hours elapsed. This item is identified as a violation of Technical Specification 3.1.6.2, Violation - Failure to Shutdown Reactor Within 24 hours of Detection of Excess Leakage, (270/85-41-01).

9. Motor Operated Valve (MOV) Switch Setpoints

The inspectors continued an inspection to determine whether the licensee has an effective program to ensure that valve operator switch settings are selected, set, and maintained properly (see report 85-38). The inspectors had become aware of numerous industry problems where improperly adjusted torque, torque bypass, or limit switches had resulted in valves failing to

operate when required either in operational events or during testing. Additionally, the recently issued IE Bulletin 85-03, addresses new requirements in certain safety related systems. The inspectors conducted this inspection to determine the extent, if any, of valve switch problems in safety related systems at Oconee.

The responsible I&E engineers contacted indicated that no formal program exists at the Oconee nuclear station for determining setpoints. Torque switch setpoints may be derived by any one of the following methods: (1) from the NSM package if specified, (2) from the electrical (OEE) drawing, if specified, or (3) field determined, i.e., setting the switch to whatever it takes to operate the valve. Thus the setpoints may not be based on engineering analysis of system pressures, valve operator size, and other factors. It was noted that switches being adjusted in the field did not appear to consider the design or operating pressures.

Based on a review of the station Inservice Inspection Program and discussions with staff test personnel, the inspectors determined that the program does not verify the adequacy of switch setpoints through testing of valves under the appropriate operating or accident pressure conditions. In many cases, safety related valves are stroke tested under conditions of no differential pressure, which may be entirely different from the conditions for which the valve(s) may be called upon to operate.

The work history of approximately 25 safety related MOVs was reviewed to determine the number of events where the MOV failed to operate properly, whether switch setpoints were a significant contributing factor, and whether adequate corrective action was taken. A large number of events were identified by the computer listing for these MOVs, however, only a selected number were evaluated by the inspector.

Review of the work histories identified many cases where torque switch setpoints were adjusted by I&E technicians in the field, using adequately detailed and documented procedures. These completed procedures then became the reference for future use by plant personnel for documentation of the setpoints. However, it is again noted that the adjustments and subsequent stroking for operability testing was completed with little or no pressure on the valve(s), a condition entirely different than may exist later.

Based on the above inspecton activities the inspectors have concluded that the licensee does not presently have an adequate program to determine the correct setpoints for switches on safety related motor operators, to document and control these setpoints, and to verify their adequacy through a test program based on testing, where possible, under actual system differential pressure conditions.

The above findings were discussed with the licensee along with a discussion of IE Bulletin 85-03, Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Setpoints were discussed. That bulletin requires licensees to develop and implement a program for selecting,

setting, and maintaining switch setpoints for MOVs on certain safety related systems.

The licensee is developing a valve improvement program, partly in response to the IE Bulletin, but also in part due to histories of valve maintenance problems. The station has recently requested Design Engineering to develop a document listing the maximum and minimum torque settings for MOVs at the Oconee Station. Additionally, the test staff and maintenance engineers are looking at methods to test valve operators under the actual system operating conditions or under similar conditions on a test stand.

While the IE Bulletin only requires development of the program for the High Pressure Injection and Emergency Feedwater systems at Oconee, the station is considering implementation of the program for other safety related systems. The inspectors will follow the development and implementation of this program.

10. Licensee Event Reports

The inspectors reviewed nonroutine event reports to verify that report details met license requirements, identified the cause of the event, described corrective actions appropriate for the idenfified cause, and adequately addressed the event and any generic implications. In addition, as appropriate, the inspectors examined operating and maintenance logs, and records and internal investigation reports.

Personnel were interviewed to verify that the report accurately reflected the circumstances of the event, that the corrective action had been taken or responsibility assigned to assure completion, and that the event was reviewed by the licensee, as stipulated in the Technical Specifications. The following event reports were reviewed:

(Closed) LER270/85-06 Reactor Trip on High RCS Pressure Following Closure of Turbine Intercept and Bypass Valves. Event was caused by a spurious signal generated while trouble shooting.

(Closed) LER287/85-01 Reactor Trip Due to High RCS Pressure. Problem was caused by a failed integrated control system module.

(Closed) LER287/85-02 Lockout of Startup Transformer. The lockout was caused by an actual fault pressure condition; however, the root cause of the pressure could not be determined.

11. Review of Unit 3 Startup

On December 16, Unit 3 was taken critical and returned to power operations following a 21 day outage to replace a bearing on the high pressure turbine. The inspectors witnessed portions of the startup to verify proper performance of plant staff, adherence to procedures, and control room coordination. Following the plant startup, the inspectors conducted a detailed review of the completed controlling procedure for unit startup,

OP/3/A/1102/01, and associated procedures required to be performed in conjunction with the controlling procedure.

The procedures were reviewed in order to determine correct procedural adherence, whether required sequences of activities were followed, whether adequate system lineups were performed or verified, and whether systems and components were verified operable as required.

No violations or deviations were identified.

12. Review of Non-Conforming Item Reports (71707)

The inspectors reviewed Non-Conforming Item Reports (NCIR) to verify that identified deficiencies are tracked via the licensee's problem identification system and that prompt corrective action is taken. A question as to the timeliness of operability reviews was raised based on inspector review of NCIR No. O-1608, as well as to the nature of the NCIR.

This NCIR dealt with an exempt change which added nipples to two thermowells on a 3/8 inch line at the pressurizer sample cooler near the primary sample hood. The addition was necessary to facilitate sampling of the reactor coolant system (RCS). The 3/8 inch line is isolated from the RCS by two remotely operated valves, one inside and one outside containment, which are normally closed except when a sample is taken.

In this Class E system, schedule 40 one inch nipples and 3000 pound one inch couplings were used to effect the exempt change. Flow diagram OFD-110A-3.1 specifies that schedule 160 piping and 6000 pound fittings be used. The inspectors discussed the matter with Duke Power Company Design personnel who stated that wall thickness, at the thread, of the nipples used was calculated to be 0.063 inches, while the code requirement for the application is 0.141 inches.

The inspectors noted that, though an operability review was required, thirty days were allowed for the review. Since the NCI dealt with what amounted to substandard material in a sample system connected to the RCS, the inspectors did not agree with the thirty day review. The licensee then isolated the affected system and reworked the modification with materials of the correct strength.

In determining the cause of the non-conforming item, the inspectors reviewed the Oconee Project Services procedure for exempt changes. In substance, the procedure requires that the site accountable engineer (A/E) contact Design Engineering for verbal approval of an exempt change (EC) concept; on approval of the EC the A/E sends detailed drawings of the change in a variation notice (VN) to Design Engineering for review; on approval by Design Engineering of final drawings and specifications the work may proceed. However, the work may proceed prior to Design Engineering approval, but the system may not be returned to service until the approval is received.

In the case of EC OE-0426, verbal approval was received for the change on October 5, 1985, and the work was performed on October 6 and the system returned to service. The site engineer who prepared the job apparently neglected to consider loss of strength due to the 316S Schedule 40 one inch nipple and coupling being threaded connections.

A variation notice (VN) detailing the modification was sent to Design Engineering on October 7 and on December 12, the VN was rejected by Design Engineering. An NCIR was not issued until January 3, 1986. On January 3 it was sent by QA to the compliance section for Operability Review. The NRC inspectors saw the NCI on January 9 and the licensee took immediate corrective action.

Technical Specification 6.4.1 states that the station will be operated and maintained according to approved procedures. Paragraph 6.4.1c of this specification includes actions taken to correct specific and foreseen malfunctions of systems or components involving nuclear safety and radiation levels. Failure to follow the exempt change procedure is an apparent violation of Technical Specification (Violation- Failure to Follow Procedure on Exempt Change, 85-41-02).

The inspectors pointed out that any conditions which possibly compromised the integrity of the RCS should have immediate review. The licensee agreed that the delay was not acceptable and that the system would have to be revised to prevent recurrence. The licensee pointed out that, due to earlier identified weaknesses in the program for problem evaluation, documentation and corrective action, the Problem Investigation Report (PIR) System had been developed and is scheduled to be implemented by June 1, 1986. The PIR will facilitate the mechanism for any employee to identify a non-conformance and initiate corrective action. The system will be coordinated by the Compliance Section. Specific time frames will be assigned to the different program elements, including the operability review, when required.

Implementation of the PIR system should resolve inspector concerns on the timeliness of performing operability reviews. The residents will follow implementation of this system, and it is listed as inspector followup item; IFI 287/85-41-03; Timeliness of Operability Reviews.

13. Inspector Followup Items

(Closed) IFI 270/81-32-03 PORV Block Valve Failures. Corrective action was taken at the time of the event to prevent recurrence. Corrective actions to assure proper maintenance on motor operated valves, as a result of plant problems and in response to Bulletin 85-03, Motor Operated Valve Common Mode Failures During Plant Transients Due to Improper Switch Settings is discussed in paragraph 9 of this report.

14. Facility Modifications (37701)

The inspectors completed their review of selected test procedures performed during checkout of the Standby Shutdown Facility (SSF). The previous report, No. 50-269,270,287/85-38, paragraph 12, discussed the SSF diesel generator in reference to IE Bulletin 79-23 which pointed out a potential generator failure due to the flow of circulating currents.

The referenced report stated that, at the factory, connections (shown as corrections in the referenced report) had not been made between low KVA rated transformers and high KVA diesel generators without adequate limitations on the flow of circulating currents. The inspector requested the licensee to verify that site installation had not compromised these limitations. The licensee inspected the generator, relative to Bulletin 79-23, and stated that it was determined to be a wye-wye ungrounded connection, which eliminated the possibility of high circulating current.

Bulletin 79-23 was closed in 1979 since Oconee, at that time, had no diesel generators. The licensee has determined that the SSF diesel generator, subsequently installed, meets the requirements of Bulleting 79-23. This item is closed.

15. TMI Action Items (NUREG-0737)

2.K.9 (Closed) Failure Modes and Effects Analysis on ICS. As a result of the correspondence from the NRC to Duke, Wagner to Parker, dated 02/03/82, this item should have been closed. This item is now considered closed.

16. Noble Gas Activity Monitor Out of Service (Unit 2)

Radiation Instrument Alarm (RIA) 45 is one of six monitors in the Unit Vent Monitoring System and monitors noble gas release. At 4:25 p.m. on December 18, 1985, 2RIA-45 was declared out of service and turnover given to repair. Repair would normally be made on the following day shift. Technical Specifications Table 3.5.5-2.2a shows that if RIA-40 is out of service, a grab sample must be analyzed every eight hours. Operations personnel did not detect this requirement.

At 8:00 a.m. on December 19, it was determined that the stack should have been sampled every eight hours. A sample was taken at 8:30 a.m. on December 19, 16 hours after the monitor was declared operable. 2RIA-40 was returned to service at 10:30 a.m. on December 19.

The licensee immediately took corrective action, reported the event to NRC, and also took corrective action to cause shift personnel to review technical specifications when an instrument is taken out of service. Failure to sample the stack within eight hours of RIA-40 being declared out of service is a violation of Technical Specification 3.5.5.2. However, the violation will not be cited since it meets the requirements of 10 CFR Part 2, Appendix C, Paragraph A.

17. Rancho Seco Overcooling Event

Upon hearing of the loss of integrated control system (ICS) power at Rancho Seco, which resulted in an overcooling event, the inspectors began a determination of the Oconee staffs reaction to the event. The staff had already begun an investigation of the Oconee plant response and the differences between Oconee and Rancho Seco, and had initiated an operator training program. On January 9, the inspectors attended an operator training class on the simulator in which operators were subjected to the loss of ICS power, loss of ICS automatic control, and loss of ICS hand control. All three result in different plant responses.

Based on the inspector's understanding of the Rancho Seco system, apparent differences in automatic response to loss of ICS power is as follows:

At Rancho Seco, main feedwater valves close to 50%, feedwater pumps run back to minimum speed, turbine bypass and atmospheric dump valves open to 50%. The reactor tripped on high pressure due to initial underfeed of the steam generators with the overcooling transient following due to steam generator overfeed and steam flow through the open bypass and dump valves. Operator response was complicated due to emergency feedwater pumps and valves having controls from the ICS, which had lost power.

At Oconee the main feedwater pumps trip on loss of ICS power, thus tripping the reactor and turbine on an anticipatory trip. The turbine bypass valves fail closed and the atmospheric dump valves have no automatic controls (chainwheel only). The Oconee engineered safety features and emergency feedwater pumps and valves are independent of the ICS.