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

Report Nos.: 50-269/91-35, 50-270/91-35 and 50-287/91-35

Licensee: Duke Power Company
P. O. Box 1007
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Docket Nos.: 50-269, 50-270, 50-287, 72-4

License Nos.: DPR-38, DPR-47, DPR-55, SNM-2503

Facility Name: Oconee Nuclear Station

Inspection Conducted: November 24, 1991 - January 4, 1992

Inspector: _____ 1/29/92
for P. E. Harmon, Senior Resident Inspector — Date Signed

_____ 1/29/92
for B. B. Desai, Resident Inspector — Date Signed

_____ 1/29/92
for W. K. Poertner, Resident Inspector — Date Signed

Approved by: _____ 1/29/92
G. A. Belisle, 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 and inspection of open items.

Results: One violation with two examples for failure to follow procedures was identified. Both examples involved controlled and configured valves being found in the wrong position. In one instance, the licensee generated a LER because the valve found out of position was a containment isolation valve. In the other instance, an inadvertent dilution of a concentrated boric acid storage tank occurred over a period of several days. These two examples indicate a problem in the configuration control area.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*H. Barron, Station Manager
*J. Davis, Quality Assurance Manager
D. Deatherage, Operations Support Manager
*W. Foster, Superintendent, Mechanical Maintenance
J. Hampton, Vice President, Oconee Site
O. Kohler, Compliance Engineer
C. Little, Superintendent, Instrument and Electrical (I&E)
*M. Patrick, Compliance Manager
*S. Perry, Assistant Licensing Coordinator
G. Ridgeway, Shift Operations Manager
G. Rothenberger, Superintendent, Integrated Scheduling
*R. Sweigart, Superintendent, Operations

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

NRC Resident Inspectors:

*P. Harmon
*W. Poertner
*B. Desai

*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 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
Units 1, 2 and 3 Spent Fuel Pool Rooms
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Keowee Hydro Station

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

Within the areas reviewed, licensee activities were satisfactory.

b. Plant Status

Unit 1 operated at power for the entire reporting period.

Unit 2 operated at power for the entire reporting period.

Unit 3 remained in a shutdown condition the entire reporting period as a result of an unisolable reactor coolant system (RCS) leak from a failed instrument fitting. During the subsequent startup after repairs and equipment inspections, a dropped control rod on December 8 forced a return to cold shutdown for repairs to several rod drive mechanisms. On December 15, during plant heatup and pressurization, a through-wall crack in the RCS decay heat removal dropline was discovered. The unit was again shut down and depressurized to repair the leak. At the end of the reporting period, the unit was in the process of returning to power.

c. Mispositioned Containment Isolation Valve

On December 9, the Operations Manager informed the resident staff of a Unit 3 containment isolation valve that had been found out of position. The valve, 3IA-91, is a 3 inch containment isolation valve for the Instrument Air System. The valve is a manually operated valve located inside containment, and is required to be closed to meet containment isolation criteria. Technical Specification (TS) 3.6.1 requires containment integrity to be established when RCS temperature is greater than 200 degrees, pressure is above 300 psig,

and fuel is in the reactor vessel. Valve position is controlled by Enclosures 13.1 and 13.2 of procedure PT/3/A/115/08, Inside Reactor Building Manual Isolation Valve Checklist Verification. The last documented manipulation of 3IA-91 occurred on March 27, 1991, when the unit was being prepared for startup after a refueling outage. Several entries into containment were performed after that date, but there had been no documented position change of the valve.

On November 30, 1991, a non-licensed operator entered the reactor building to perform valve lineups, including opening valve 3IA-91. The NLO found the valve in the open position and notified the Unit 3 supervisor. Several individuals had made containment entries since the November 23 shutdown, but none questioned admitted operating the valve. The valve is not in a high traffic area in containment, and is not subject to inadvertent operation. A Shift Incident Report (SIR) was initiated on December 1, 1991, but an LER was not immediately initiated. An LER was initiated on December 9. The station Compliance Manager informed the inspectors that this LER would not be complete within the required 30 days from discovery of the event, primarily due to the relatively late start on preparing the LER and the intervening Christmas holidays. The licensee sent a memo to AEOD stating that the LER would be late.

The inspectors discussed with site management the lack of timeliness in the licensee's investigation into the circumstances of this event. In addition, the fact that 9 days passed before the resident inspector staff was notified of the event is not acceptable.

Failure to meet the requirements of procedure PT/3/A/115/08 resulted in a mispositioned valve and a lack of configuration control for a containment isolation valve. This item is identified as Violation 50-287/91-35-01: Inadequate Configuration Control.

d. Unit 3 Loss of Feedwater

On December 7, 1991, at approximately 3:45 p.m., with the reactor coolant system at 1230 psig and 519 degrees F, the operating Hotwell pump (3A) tripped followed by the operating condensate booster pump (3A) and the operating main feedwater pump (3A) resulting in a loss of feedwater to the steam generators. At the time of the event the unit was subcritical and in the process of heating up in preparation of returning the unit to service. A hotwell pump and condensate booster pump were restarted and the 3A main feedwater pump was reset and feedwater was reestablished to the steam generators at approximately 3:48 p.m. The lowest level reached in the steam generators was 19 inches on the startup range level instruments. The inspectors were in the control room during the event and monitored the operators actions to restore feedwater.

The licensee determined that the trip signal was generated by an erroneous low hotwell level signal from level switch 3LS-28. The level switch was checked and no problems could be found with its operation or setpoint. The licensee theorized that relay chatter associated with the feedwater pump low discharge pressure relay that is physically located approximately four inches above the hotwell low level relay may have caused the low level relay to actuate. To prevent an inadvertent trip signal from being received with the unit at power, the hotwell low level trip signal was removed from service. The licensee based this decision on the fact that the trip signal is for pump protection only and a plant modification package had been requested previously to delete the low hotwell level trip signal.

e. Unit 3 Water Hammer

On December 9, 1991, at approximately 5:30 a.m., a water hammer event occurred on Unit 3 when the operators in the control room attempted to place steam generator hot blowdown in service. The inspectors were in the turbine building at the time of the event and heard the water hammer occur. The inspectors toured the turbine building and observed piping insulation on the floor around the Unit 3 emergency switchgears and several pipe supports that had been ripped from the wall. The inspectors proceeded to the control room and determined that the water hammer had resulted when valves 3FDW-103 and 3FDW-104 had been opened to reestablish hot blowdown. Hot blowdown had been secured during the Unit 3 startup. However, the startup had been stopped due to a dropped rod and the unit was returning to cold shutdown to replace the control rod drive stator of the rod that had dropped. At the time of the event steam generator pressure was approximately 850 psig. The licensee walked down the piping, evaluated the damage resulting from the water hammer and repaired the broken hangers. At the conclusion of the inspection period the licensee was evaluating potential procedure changes to prevent a recurrence of this event.

f. Erroneous Estimated Critical Position (ECP) Calculation

On December 8, 1991, an ECP calculation was performed by the night shift operations crew in preparation for the Unit 3 startup and approach to criticality. The ECP calculation determined that criticality would be achieved at 19% withdrawn on group 6 based on a reactor coolant system (RCS) boron concentration of 1304 ppm. The calculation was performed per Enclosure 13.2 of PT/3/A/1103/15 and had been independently verified as correct. Subsequent to shift turnover, the oncoming shift questioned the adequacy of the ECP calculation based on the RCS boron concentration prior to the unit shutting down. The oncoming shift performed another ECP calculation per PT/3/A/1103/15 and did not obtain the same results as the previous shift had achieved. The previous ECP calculation was

reviewed and it was determined that the error was a result of not reversing the reactivity coefficient sign in step 13.2.6 of the procedure as specified in the procedure. Review of the incorrect ECP calculation determined that both the person performing the ECP and the independent verifier had made the same error when performing the calculation. The error introduced into the ECP calculation was in a conservative direction such that criticality would not have been achieved early in the rod withdrawal sequence. The licensee initiated a shift incident report on this event and continued with unit startup activities.

g. Valve 3CS-60 Mispositioned

On December 17, 1991, with the 3A bleed transfer pump taking a suction on the concentrated boric acid storage tank (CBAST) and adding water to the letdown storage tank (LDST) to increase the reactor coolant system boron concentration, the expected increase in system boron concentration was not achieved for the amount of boric acid that had been injected into the RCS. A water sample of the 3A bleed transfer pump discharge was obtained with the pump running and the results indicated 3317 ppm boron instead of the expected CBAST concentration of 10550 ppm boron. Investigation by the operators determined that valve 3CS-60 was open approximately 5 turns instead of in its required position of closed. Valve 3CS-60 is the bleed transfer pump suction crossconnect valve and with the valve open the 3A bleed transfer pump was taking a suction on the CBAST and the 3B bleed holdup tank simultaneously. The boron concentration in the 3B bleed holdup tank was less than 10 ppm and resulted in the reduction of the expected increase in boron concentration of the RCS. Valve 3CS-60 in the open position also allowed water from the 3B bleed holdup tank to enter and dilute the CBAST. A boron sample of the CBAST was taken and indicated a boron concentration of 5341 ppm in the CBAST as opposed to the expected 10550 ppm.

The licensee could not determine when 3CS-60 had been opened. Review of the completed procedure files determined that the valve had been opened on December 9, 1991, to borate the RCS from the CBAST using the 3B bleed transfer pump; however, the procedure returns the valve to the shut position and requires that the valve be independently verified as shut after the boron addition and the system is flushed. The inspectors consider this item not only a configuration control problem but also a reactivity management issue. The failure to maintain configuration control of valve 3CS-60 is identified as a second example of violation 50-287/91-35-01 discussed in paragraph 2.c.

Within the areas reviewed, one violation with two examples was identified.

3. Surveillance Testing (61726)

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 system restoration was completed.

Surveillances reviewed and witnessed in whole or in part:

| | |
|---|---|
| PT/0/A/115/07 | Reactor Building Spray Valve Verification. |
| PT/0/A/305/01 | Reactor Manual Trip Test. |
| PT/0/A/201/04 | PORV Operability Test. |

Within the areas reviewed, licensee activities were satisfactory.

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 36230C | Investigate and repair RPS Channel A Hot Leg Temperature Indication |
| WR 35864C | Repair 1CCW-304 |
| Unit 3 CRDM | Stator Checkout/Replacement |
| Unit 3 Decay Heat Removal | Dropline Pipe Replacement |

Within the areas reviewed, licensee activities were satisfactory.

No violations or deviations were identified.

5. Unit 3 Forced Outage

Unit 3 experienced a Reactor Coolant System (RCS) leak greater than 50 gpm on November 23, 1991, and subsequently had to be shutdown. The leak was caused when an improperly installed compression fitting failed. Details of the event are discussed in NRC Inspection Report (IR) 50-287/91-34. The unit was still shutdown for repairs at the end of the inspection period for IR 50-287/91-34 and all the activities conducted during the outage were not captured in the special inspection report. The following items occurred during the Unit 3 forced outage and were not addressed in IR 50-287/91-34.

a. Control Rod Drive Mechanism Problems

Following the RCS leak, various components in the reactor building were inspected by the licensee for possible moisture intrusion. Included in the components inspected were the Control Rod Drive (CRD) mechanisms. Due to airborne contamination in the reactor building, the CRD stators were initially tested from the cable spreading room on November 26, 1991. Specifically, testing involved meggering to measure resistance to ground values. The resistance values found from the cable spreading room were below the acceptance criteria of 200 megohms or more. Low resistance values indicate that there may be a problem with the stator or the insulation. Since all of the readings taken from the cable spreading room were low, the licensee decided to remegger the stators from within the reactor building. The licensee chose eighteen stators and obtained megger readings from the bulkhead (side wall of the refueling canal where the cables from all stators are centrally located) to the stator. All eighteen stators meggered above the value of 200 megohms. The licensee concluded that the readings from the cable spreading room were in error and that all the CRD mechanisms were free of any moisture instrusion.

On December 8, 1991 during Unit 3 startup, CRD group 5, rod 6 dropped into the core. Startup was halted and investigation by the licensee indicated that two phases of the stator had shorted together causing the rod to drop into the core. The unit was cooled down to repair the stator and a decision was made to megger all sixty nine stators. The stator for the dropped rod meggered above the acceptance criteria; however, the connector was found to have moisture in it. When meggering on all sixty nine stators was completed, there were twenty nine stators that did not meet the designated acceptance criteria. Consequently, they had to be removed from the vessel head and dried. Drying involved nitrogen purging and then, if needed, electrical drying of the stators. After drying, the twenty nine stators were remeggered and at this time three stators did not meet the acceptance criteria. The licensee decided to replace the three

stators with new stators. In addition, one more stator had to be replaced due to physical damage experienced when that stator was dropped during handling. The licensee also replaced twenty four connector inserts with a new type of insert that is thought to be a better quality insert. After reinstalling the twenty stators and the connector inserts, the licensee remeggered all the stators and all but one meggered within the acceptance criteria. This stator was redried and subsequently meggered greater than 200 megohms. With all sixty nine stators meggering above the acceptance criteria, the licensee decided to proceed with unit startup.

On January 3, with RCS temperature at 240 degrees F, the stators were again meggered. At this time four stators did not meet the acceptance criteria of at least 200 megohms. The licensee decided to proceed with the startup. This decision was based on industry experience and the fact that the 200 megohm guideline set by B&W was for new stators. The stators in question were not newly installed and due to some wear, the licensee postulated that megger readings could be expected to be a lower value and the stator would still be reliable. The licensee, at RCS temperature of 410 degrees F, again meggered the four stators that had meggered below 200 megohms at RCS temperature of 210 degrees. The results showed that meggering values for stator readings had dropped slightly and two had risen substantiality. Apparently, moisture from the leak had collected in the stator at the bottom of the stator conduit and therefore the initial reading at shutdown was not affected. However, as heatup began, moisture began to evaporate up the stator tube where it cooled and condensed and then traveled back down the tube where it was cooled. This moisture trapped inside served to lower the megger readings obtained during the subsequent checkout.

b. Through-Wall Crack in the Decay Heat Removal Dropline

At 8:30 a.m., on December 15, 1991, during a tour of the reactor building, the licensee noticed a small leak coming from the decay heat dropline. The exact location of the leak could not be identified due to insulation. However, the leak was in the vicinity of the decay heat drop line isolation valve 3LP-2. At this time the unit was at 130 degrees F, 30 psig, with a pressurizer bubble established and Low Pressure Injection (LPI) aligned in the decay heat removal mode. The leak was later identified as coming from a crack on the decay heat dropline where a 3/4 inch piping relief valve, 3LP-25, connects to the dropline. The licensee determined that the piping could possibly fail during further RCS pressurization. A decision was made on December 15 to depressurize and cooldown to accommodate replacement of the portion of piping with the crack. Additionally, the dropline had to be isolated to enable pipe replacement. To remove decay heat, the licensee developed a special procedure which involved aligning the spent fuel pool pumps to force circulation through the core. With the refueling canal full, vessel head removed, decay heat dropline isolated, the spent fuel pool pump

would take suction from a low point in the refueling canal and force water through the core via the LPI headers. The spent fuel cooler as well as the LPI coolers were available heat sinks.

The licensee encountered some problems during filling the refueling canal. The canal seal plate was not leak tight during the initial fill. The canal had to be drained and portions of the rubber gasket had to be shimmed to make the canal seal plate completely leak tight. The licensee did not encounter any problems controlling core temperature at approximately 90 degrees F during the time that they were in the special spent fuel pump alignment.

The portion of the pipe with the crack was cut out and sent out to Babcock and Wilcox (B&W) for analysis. A replacement pipe was welded on the decay heat dropline. Preliminary analysis done by B&W indicated that the failure mode for the decay heat dropline pipe was high cycle, low amplitude load fatigue. There were no indications of corrosion contributing to the failure. An NRC special materials inspector closely followed the licensee's actions pertaining to the crack and pipe replacement. Details of this issue will be documented in NRC Inspection Report No. 50-287/91-37.

No violations or deviations were identified.

6. Inspection of Open Items (92701)

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

(Closed) Inspector Followup Item 50-269,270,287/90-34-01: Corrective Actions Associated with LPSW Pilot and Solenoid Operated Valves for MDEFW Pumps. The licensee replaced the valve operator for the valves in question with a different design of operator that does not use air as the motive force to open the valve.

7. Exit Interview (30703)

The inspection scope and findings were summarized on January 10, 1992, 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.

| Item Number | Description/Reference Paragraph |
|---|---|
| VIO 50-287/91-35-01 | Inadequate Configuration Control (paragraphs 2.c and 2.g) |