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

Report Nos.: 50-269/93-20, 50-270/93-20 and 50-287/93-20

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-0001

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: May 30 - June 26, 1993

Inspector: W. H. Miller Jr. — 7/15/93
for P. E. Harmon, Senior Resident Inspector — Date Signed

W. H. Miller Jr. — 7/15/93
for B. B. Desai, Resident Inspector — Date Signed

W. H. Miller Jr. — 7/15/93
for W. K. Poertner, Resident Inspector — Date Signed

Approved by: M Lesser — 7/15/93
M. S. Lesser, Section Chief — Date Signed

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance activities, inspection of open items, review of licensee event reports, and Keowee commitments.

Results: One violation (VIO) was identified concerning the operation of the Keowee Hydro units above the procedural guidelines established in the operating procedure by the inappropriate use of a Keowee Station Memorandum (paragraph 7). Additionally inattention to detail by the Keowee operators allowed the Keowee units to be operated above the maximum analyzed load.

One Inspector Followup Item (IFI) was identified concerning instrument impulse lines and associated Inservice Inspection Code Class requirements (paragraph 4).

One Inspector Followup Item (IFI) was identified concerning piping and component Code Class requirements for safety related systems (paragraph 4).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*H. Barron, Station Manager
S. Benesole, Safety Review Manager
D. Coyle, Systems Engineering Manager
J. Davis, Safety Assurance Manager
T. Coutu, Operations Support Manager
*B. Dolan, Manager, Mechanical/Nuclear Engineering
W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
D. Hubbard, Component Engineering Manager
C. Little, Superintendent, Instrument and Electrical (I&E)
*M. Patrick, Regulatory Compliance Manager
B. Peele, Engineering Manager
*S. Perry, Regulatory Compliance
*G. Rothenberger, Operations Superintendent
R. Sweigart, Work Control Superintendent

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

NRC Resident Inspectors

P. Harmon
*W. Poertner
*B. Desai

NRC Personnel

W. Miller

*Attended exit interview.

2. Plant Operations (71707)

a. General

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification log and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & electrical (I&E), and engineering personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and night shifts, during weekdays and on weekends. 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
Unit 2 Containment
Station Yard 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.

b. Plant Status

Unit 1 operated at power for the entire reporting period.

Unit 2 remained in a refueling shutdown until June 24, when the refueling outage was completed and the unit placed on-line at 12:56 p.m. Full power escalation was in progress at the end of the reporting period.

Unit 3 remained at power for the entire reporting period.

c. Rod Drop Testing

On June 21, the licensee performed rod drop timing tests on Unit 2 control rods as part of the routine testing program following the refueling outage. The testing was conducted using Instrument Procedure (IP) 0/A/0330/003A, Control Rod Drive Rod Drop Time Test. Rod 3 of Group 1 dropped in 1.641 seconds. The technical specification (TS) operability limit is 1.66 seconds. Although the drop time was marginally acceptable, the licensee decided to perform the test again. The second drop time was 1.663 seconds, and the rod was declared inoperable. A third test resulted in a drop time of 1.621 seconds. Three additional tests resulted in significant improvement in drop times, (1.415, 1.384, 1.377). The licensee believes the change in drop times from the 1.6 second to the 1.4 second time frames was the result of the sudden dislodging of particles or minute debris from the ball check valves in the rod's thermal barrier hydraulics section. If the check valve is hampered from opening during a rod drop, hydraulic displacement is delayed, causing the rod to drop more slowly. After the third drop, the step change in drop time may have been due to the expulsion of the suspected debris.

The issue of slow rod drop times and the licensee's previous actions were discussed in NRC Inspection Report No. 50-269,270,287/93-17. In that report, the licensee's practice of dropping slow rods repeatedly to gain marginal improvements in drop times was determined to be a violation of NRC requirements. In the instance described in this report, the rod in question was also dropped several times, but not to achieve an acceptable drop time.

To confirm that the subject rod had in fact been cleared of the mechanism which had caused it to exhibit slow drop times, the licensee performed an additional drop of all Unit 2 rods on June 22. In this instance, all rods dropped within the allowable time frame. Additionally, each rod was determined to be within an acceptable range of the average times for other rods in the group. Based on the results of this test, the licensee declared Group 1, Rod 3 operable.

The licensee's performance in resolving this issue was judged to be conservative, thorough, and commensurate with the safety significance of the issue. In all instances observed by the inspector, the licensee's personnel used appropriate procedures and documented results correctly.

d. Inoperable Turbine Driven Emergency Feedwater Pump

At 1:56 a.m. on June 22, the Unit 1 turbine driven emergency feedwater pump (TDEFWP) auxiliary oil pump status alarm, EFWPT AUX OIL PUMP OVERLOAD, was received in the control room. Work request WR 40704C was written and used to investigate the problem. The dispatched Instrumentation and Electrical (I&E) crew found control power fuses blown in the TDEFWP auxiliary oil pump start circuit. The TDEFWP was declared inoperable since the TDEFWP automatic start feature is defeated if the auxiliary oil pump is out of service. Further investigation revealed that the blown fuses were caused by a shorted relay, AR-15. In addition to providing functions in the auxiliary oil pump's control circuit, this relay supplies Status Alarm 1SA-8, location E-2 in the control room. The inspector questioned the licensee as to whether the relay design would allow for an alarm circuit fault to cause a failure of the safety-related component being monitored. At the end of the report the licensee's evaluation was in process and the root cause analysis had not been completed. This is identified as

Inspector Followup Item 269/93-20-04: Alarm Circuit/Control Circuit Interface. The failed relay was replaced, and the TDEFWP was declared operable.

e. Bulletin 93-02

The inspectors reviewed the licensee's actions taken to address NRC Bulletin NO. 93-02, Debris Plugging of Emergency Core Cooling Suction Strainers. The Bulletin required the licensee to identify fibrous air filters or other temporary sources of fibrous material, not designed to withstand a LOCA, which are installed or stored in containment.

The licensee responded to Bulletin 93-02 by letter dated June 9, 1993. The licensee's response stated that no fibrous filters are installed inside containment during unit operation and a detailed inspection of the reactor building and emergency sump is performed prior to startup from a refueling outage or major maintenance outage. The licensee reviewed maintenance activities to ensure that no fibrous materials could be left in containment following an outage. Operations Management Procedure 1-6, Operating Status and Housekeeping Tours, was revised to include specific guidance to look for debris or fibrous material when performing hot shutdown tours prior to returning a unit to operation.

The inspectors reviewed the licensee response and performed an inspection of the Unit 2 containment and emergency sump area prior to Unit 2 returning to service from the refueling outage. The inspectors did not identify any temporary fibrous material inside containment.

f. Unit 3 Runback

On June 2, at 4:36 p.m. Unit 3 experienced a runback from 100 percent power. The runback was initiated due to an asymmetric rod signal to the integrated control system. The operator in the control room took manual control of the control rods and terminated the runback at 93 percent power. The licensee determined that the runback was caused by the loss of a group out limit indication on a safety rod group. The loss of the out limit was attributed to load shed testing being conducted on Unit 2. Unit 2 supplies the alternate control rod drive (CRD) power supply to Unit 3, and loss of the alternate power supply resulted in the safety rods aligning with the single DC hold power supply. The slight realignment of the rods resulted in the loss of the group out limit indication on one of the safety groups and initiated the runback. The operators restored the alternate CRD power supply which regained the group out limit indication and cleared the asymmetric rod indication. The unit was subsequently returned to 100 percent power. The inspectors determined that the licensee is aware of the potential for a runback to occur during activities of this nature. The licensee does not consider it to be a problem and tolerates the condition. The inspectors considered it to be an unnecessary challenge to the operators.

g. Inoperable Containment Isolation Valve

On June 10, at 5:30 p.m. the licensee declared containment isolation valve 3HP-21 inoperable. Valve 3HP-21 is an air operated containment isolation valve located outside the Unit 3 Reactor Building and isolates the reactor coolant pump seal return line on an engineered safeguards signal. The licensee determined that the potential existed for the valve to reopen approximately three or four hours after closing if instrument air was lost to the valve actuator and the isolation valve inside containment failed to isolate the penetration. The valve reopening could occur due to the air pressure in the accumulator on the valve actuator bleeding off on a sustained loss of instrument air and RCS pressure forcing the valve disc off its seat. The licensee performed a calculation which verified that the valve would remain closed for at least three hours and that the valve could be accessed under accident conditions by maintenance personnel. Based on these calculations, the licensee revised abnormal procedures to require maintenance personnel to close the valve's manual operator if a containment isolation occurs coincident with a loss of instrument air, to ensure that the valve will remain in the closed position. The licensee also performed an operability evaluation to declare the valve operable based on the compensatory actions in place. The valve was declared operable at approximately 11:59 p.m. after the procedure changes were incorporated.

The Unit 1 and Unit 2 HP-21 valves are identical to the Unit 3 valve. Unit 2 was shutdown for a refueling outage and 2HP-21 was not required to be operable when this problem was identified. Unit 1 was operating at 100 percent power when this problem was identified but the seal return line on Unit 1 contains a relief valve inside containment that would maintain pressure below the value required to open the valve assuming a loss of instrument air. The Unit 2 and 3 seal return lines do not contain relief valves inside the reactor building. The licensee's long term corrective actions will be followed by review of the licensee event report required to be submitted by 10 CFR 50.72.

No violations or deviations were 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 systems restoration was completed.

Surveillances reviewed and witnessed in whole or in part:

- PT/2/A/0261/07, Emergency CCW System Flow Test. The purpose of this procedure is to verify ECCW system performance and verify ECCW flow can be maintained for at least 4 hours. The inspectors witnessed the performance of this procedure and verified that ECCW flow was maintained for four hours and that the licensee's ECCW flow acceptance criteria was achieved. The adequacy of the test, regarding system alignment with the vacuum priming system, remains unresolved (refer to Unresolved Item 269,270,287/93-13-03).

- PT/2/A/0251/23, Low Pressure Service Water System Flow Test. The purpose of this procedure is to verify proper low pressure service water (LPSW) system performance and to obtain system flow data. The inspectors monitored portions of the testing performed and reviewed selected flow data obtained.

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 activities reviewed and witnessed in whole or in part:

- TN/2/A/2861/00, LPI Cooler 2A Upgrade. This modification upgraded the 2A Low Pressure Injection (LPI) cooler channel head and installed piping and valves in the LPI dropline to the suction of the LPI pumps to allow the use of the 2A LPI cooler during a unit shutdown. Prior to this modification, the 2A LPI cooler could not be used for decay heat removal until reactor coolant system pressure was reduced to less than 125 pounds per square inch (psig). The inspectors observed portions of the work activities associated with this modification and reviewed the completed modification package. During review of the completed modification package the inspectors noted that Task 33 rerouted the impulse lines to pressure gauges PG 0021 and PG 0006; that the impulse lines were identified as Duke Class G; and that the work activity performed was accomplished according to Duke Class G requirements. Duke Class G is non QA. Pressure gauges PG 0021 and PG 0006 provide local indication of pump discharge pressure and DP across the pump and are not safety related instruments. These instruments are not isolated during normal operation. The inspectors questioned the accountable engineer and determined that impulse lines to non safety related instruments are considered Duke Class G components. The inspectors questioned the acceptability of treating non-isolated impulse lines as non-safety/non-QA components. The licensee stated that the impulse lines in question were rerouted consistent with the original Construction Code and that the configuration was acceptable. The licensee stated that a design study had been performed in 1989 to evaluate instrument impulse lines and that the design study found the as-built configuration acceptable. The inspectors requested that the results of this design study be provided for review. The inspectors were unable to determine what the original construction code was. This item is identified as Inspector Followup Item (IFI) 269,270,287/93-20-01: Instrument Impulse and Associated ISI Requirements.

- TN/2/A/2888/00, Replace/Delete LPSW Control Valves. This modification replaced and rerouted valves 2LPSW-251,252,254 and 256; deleted valves 2LPSW-77,78,253,and 255; and replaced valves 2LPSW-71 and 72. The inspectors observed portions of the work activities associated with this modification package and reviewed the completed modification package. The inspectors identified that four of the six valves installed by the modification were identified as Duke Class F components. Duke Class F consists of commercial grade components that are seismically supported. The portion of the low pressure service water system modified is identified as ISI Class C/Duke Class F on the system flow diagram. The inspectors questioned the acceptability of installing commercial grade components in safety related systems. The inspectors identified a similar concern in NRC Inspection Report No. 50-269,270,287/93-17 concerning containment penetrations not being maintained to the ISI requirements. The licensee position is that ASME Section XI allows repair and replacement in accordance with the Owners Design Specification and Construction Code. The inspectors were unable to determine what the original construction code was. This item is still being evaluated by NRC and is identified as Inspector Followup Item (IFI) 269,270,287/93-20-02: Review of Piping and Component Code Class Requirements.

No violations or deviations were identified.

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

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

a. (Closed) Inspector Follow-up Item (IFI) 269,270,287/90-30-03: Review of IST Criteria for Pump Testing. The inspectors were concerned that the upper differential pressure limit for the Reactor Building Spray Pump was not in accordance with ASME Section XI requirements. Subsequent NRC Violation 269/90-33-01, Failure of Procedure to Adequately Incorporate the Licensee's Requirements for ASME Section XI Pump Testing, which was related to this item was issued. This violation was closed in NRC Inspection Report No. 50-269,270,287/92-09. The inspectors reviewed the corrective action for the violation and reviewed procedure PT/2/A/0204/07 to verify that the appropriate corrective action had been completed.

b. (Closed) Violation 269,270,287/92-03-02: Inadequate Fuel Movement Procedure. The licensee responded to this violation by letter dated March 25, 1992. The violation involved a fuel assembly which was damaged while staging it for hold down spring repair work activities. B&W procedure FO-406, MK-B5/B6/B7/B8 Hold Down Spring Removal and Replacement Procedure, has been enhanced to ensure that a 5.5 inch pedestal is used at Oconee. Site procedure PT/0/A/0750/04, Fuel Assembly Hold Down Spring Replacement, has been revised to verify that adequate clearance is provided between the bridge mast and the fuel assembly control equipment.

The following procedures were enhanced to allow them to stand alone with respect to fuel movements:

- PT/0/A/0124/06 Ultrasonic Testing of Fuel Assemblies
- PT/0/A/0750/04 Fuel Assembly Hold Down Spring Replacement
- PT/0/A/0750/05 Fuel Assembly Post Irradiation Inspection
- PT/0/A/0750/06 Fuel Assembly Reconstitution and Recaging

These procedures include all limits and precautions required for fuel movement. Steps have also been added to identify the location from which fuel assemblies are removed and the location to which the fuel assemblies are placed. The Reactor Engineering Group was provided with additional training on these procedures. Special emphasis was placed on the fuel assembly pedestal.

c. (Closed) IFI 269,270,287/92-09-01: Concentrated Boric Acid Storage Tank (CBAST) Concerns. During a review of the High Pressure Injection (HPI) and Chemical Addition Systems, the inspectors found that the control room operators maintained the CBAST level and boron concentration level in accordance with a curve in procedure OP/0/A/1108/01. According to the licensee, this curve was developed to assure that the CBAST contained the equivalent to 1100 cubic feet of 11,000 ppm boron. The curve allowed a boric acid concentration of 4250 ppm if CBAST level was 130 inches. The TS Bases for TS 3.2 states that the quantity of boric acid in the CBAST is sufficient to borate the Reactor Coolant System (RCS) to a 1 percent delta k per k subcritical margin at cold shutdown conditions.

The licensee's justification for this curve is provided in Calculation OSC-4851 and the corresponding 10 CFR 50.59 evaluation. However, to resolve the concern, the licensee revised the TS Bases for TS 3.2 on January 14, 1993, to reflect the use of the HPI pumps taking suction from the Borated Water Storage Tank (BWST) as an alternate method of boration. The inspectors discussed this item with NRR and NRR concurred with the licensee's resolution to this item. Therefore, this is item is closed.

d. (Closed) Violation 270/92-10-01: Incorrectly Performed Nuclear Instrument Reliability Check. The licensee responded to this violation by letter dated June 18, 1992. This violation was identified during the Shutdown Risk and Outage Management Inspection and involved the reload of fuel assemblies into the Unit 2 reactor prior to performing a nuclear instrumentation reliability check. The corrective action included revisions and enhancements to Enclosures 4.2, 4.13, and 4.19 to Procedures OP/1,2,3/A/1502/07, Refueling Procedure. Steps were also added to the procedure to require documentation of the nuclear instrumentation reliability checks at the beginning of fuel unload and reload shuffles and to stop all fuel movements until the reliability checks are completed.

e. (Closed) Violation 270/92-10-02: Lack of Independent Safety Tag Verification. The licensee responded to this violation by letter dated June 18, 1992. This violation was identified during the Shutdown Risk and Outage Management Inspection and involved the improper verification of tags prior to starting work activities. The corrective actions included enhancements to the tagging program. Training was provided to the Maintenance Supervisors on the tag verification requirements of Station Directive 3.1.1, Tagging. Standard block tagout forms have also been developed for block tagouts. These block tagout forms or verification sheets are developed by the Planning Coordinator(s) for use by the Block Tagout Team Supervisor as an aid in controlling the systems affected by the block tagouts. Each tag used in the block tagout is identified on this sheet.

f. (Closed) Violation 270/92-10-03: Failure to Perform a Safety Evaluation for a Temporary Modification. The licensee responded to this violation by letter dated June 18, 1992. This violation was identified during the Shutdown Risk and Outage Management Inspection and involved the installation of an electrical jumper on a radiation monitor without initiating a temporary modification package or performing an engineering evaluation. For corrective action, the license issued Operations Training Package 92-15 which described this event. This package was required to be reviewed by the Senior Reactor Operators and other members of the Operations staff, and was also discussed with the Project Manager group, Engineering, and I&C personnel. These discussions stressed sensitivity to interlocks and operating features during work activities associated with temporary modifications.

g. (Closed) Violation 269,270,287/92-14-01: Unit 1 Restarted With Only One of the Two Required Emergency Feedwater Flow Paths Operable.

(Closed) Violation 269,270,287/92-14-02: Unit 1 Restarted Without an Adequate Trip Review.

The licensee responded to these violations by letter dated August 24, 1992. These violations were considered for escalated enforcement and an NRC Enforcement Conference was conducted on July 17, 1992.

The licensee's corrective actions to prevent recurrence included the replacement of the solenoid valve for valve 1FDW-316 with a Valcor Model V70900-65 solenoid. Procedure PT/1,2,3/A/0150/22M was also revised to require valves 1FDW-315 and 1FDW-316 to be tested quarterly. Enhancements were made to Procedure PT/0/A/0811/02, Reactor Trip Review Procedure. A caution statement and a verification step were added to this procedure to ensure that flow through both Emergency Feedwater headers is observed. Verification was also added to verify that other safety systems function when required.

h. (Closed) Violation 269,270,287/92-15-01: Failure to Follow Procedure. The licensee responded to the violation by letter dated September 17, 1992. The violation occurred after an I&E Technician marked a drawing as an aid, but accidently marked the incorrect termination location. Another technician made the wiring termination in accordance with the markings on the drawing. For corrective action the licensee reviewed this incident with I&E Technicians and QC Inspectors. These personnel were instructed not to mark or highlight wiring and modification changes. Maintenance Directives 7.5.3, Maintenance Paper Work Request Implementation, and 7.5.8, WMS Work Order Task Package, were revised to provide clearer instructions and requirements necessary to control plant changes. Maintenance Directive 4.4.13, I&E Configuration Control Work Practices, was revised to clarify the requirements for marking lifted leads that are removed from normal position and left unattended and the controlling of lifted leads that are not controlled by a procedure.

i. (Closed) Violation 287/92-18-01: Mispositioned Nitrogen Supply Valve. The licensee responded to this violation by letter dated October 15, 1992. This violation was caused by the failure to properly close a nitrogen supply valve which resulted in the inadvertent admission of nitrogen to the pressurizer and quench tank. For corrective action following this event, management discussed the event with the operators involved and with operations staff. Other recent mispositioned events were also discussed. Proper prejob briefing, control of working procedures and communication techniques were also stressed.

j. (Closed) Violation 269/92-23-01: Containment Isolation Valve Found Open. The licensee responded to this violation by letter dated November 18, 1992. This violation involved a containment isolation valve in the nitrogen supply piping to the Unit 1 Pressurizer which was not closed prior to exceeding 200 degrees F and 300 psig in the Reactor Coolant System. To prevent recurrence, the licensee revised Procedure OP/1/A/1103/02 to require valve 1N-107 to be closed when the use of nitrogen in the Reactor Building is completed. Valve 1N-107 does not supply Units 2 and 3; therefore, the procedures for Units 2 and 3 were not required to be revised. Enclosure 4.1 to Procedure OP/1,2,3//A/1102/01, Controlling Procedure for Unit Startup, was revised to require completion of the Containment Integrity Checklist after completion of the procedures that affect containment isolation valves.

6. Review of Licensee Event Reports (92700)

The below listed Licensee Event Reports (LER) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, verification of compliance with Technical Specification and regulatory requirements, corrective actions taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. The following LERs were reviewed:

a. (Closed) LER 269/90-14, Equipment Malfunctions and Management Deficiency Results in TS Violation on Core Flood Tank Level. The licensee discovered the level of Core Flood Tank 1B to be below the TS required minimum value. This was discovered during instrument calibration activities which found both strings of the core flood tank level transmitter instrumentation out of tolerance. The Core Flood Tank level was also found to be below the TS minimum level. The licensee repaired the instrumentation and increased the Core Flood Tank level to above the TS minimum limit.

The following corrective actions were implemented:

- Maintenance and Operations personnel reviewed procedures and identified the procedures which were related to filling and verifying levels of reference legs.

- Procedures which outlined the steps needed to maintain reference leg fill during removal from service, calibration and returned to service were developed.

- Training was provided to all I&E personnel on the procedures to be followed for filling reference legs.

- The instrument root valves associated with Core Flood Tank 1B were replaced.

- Maintenance Engineering Services tracked the performance of Core Flood Tank level instrumentation for 6 months. No major problems were identified, but several minor problems were identified and corrected. The performance of this instrumentation is continuing to be evaluated by the licensee.

b. (Closed) LER 269/91-10, High Pressure Injection (HPI) System Technically Inoperable for Some Single Failure LOCA Scenarios Due to Design Deficiency. The licensee's Design Engineering organization found that the operating limit curve for the Letdown Storage Tank (LDST) pressure versus level was inadequate. The use of this curve could permit operation outside the design basis for the emergency injection function of the HPI System. In the event of a small break LOCA, a single failure could result in hydrogen gas from the LDST expanding into the suction piping of the HPI pumps, causing damage to the pumps.

The licensee provided operations personnel with verbal guidance for maintaining the LDST within revised limits and the action to be taken in the event of the accident scenario until the operations procedure was revised.

The inspectors verified that the following corrective action had been implemented:

- The operating procedure was revised to incorporate a revised LDST Pressure versus Level Curve.

- The Emergency Operating Procedure was revised to require the immediate line-up in the "piggy back mode" if a single failure of valves HP-24 or HP-25 should occur during a small break LOCA.

  An engineering evaluation developed a more restrictive curve. However, this more restrictive curve could cause chemistry problems for Unit 3 due to the more restrictive piping configuration for this unit. The more restrictive curves are being used, but the operators will be allowed to exceed the limits on the curve should chemistry problems arise. The procedural guidance to go to the "piggy back mode" of operation for failure of valve HP-24 or HP-25 to open has been retained in the Emergency Operating Procedures.

- Station Directive 2.2.1, Station Procedures, was revised to require curves and tables included in site procedures to be revised as necessary to reflect any changes to information that was used to create them.

c. (Closed) LER 269/91-12, Design Deficiency in Establishing Relief Valve Setpoint Results in Technical Inoperability of Alternate

Reactor Coolant Makeup System. The LER involved the relief valve for each unit's Reactor Coolant Makeup System (RCMU). The relief valves had a setpoint that would have resulted in the valves opening during an event requiring the operation of the RCMU system. This resulted in RCMU Systems for all three units being inoperable since initial installation in 1981. With the relief valve open, the RCMU pumps do not have sufficient capacity to provide adequate reactor coolant pump seal flow to prevent a possible seal failure and the resulting loss of reactor coolant in excess of the makeup capability of the RCMU pumps. The relief valves were replaced with new valves which have a higher actuation setpoint.

d. (Closed) LER 269/91-13, Post LOCA Decay Heat Removal System Declared Technically Inoperable Due To Design Deficiency. This LER was issued following B&W's identification that under certain LOCA scenarios, boron precipitation inside the reactor core would occur sooner than had previously been analyzed. This required the LOCA Boron Dilution System to be placed in service significantly earlier than previously required in order to avoid boron crystallization on the fuel assemblies and resulting degraded heat transfer. The licensee provided interim administrative instructions to operations on November 4, 1991, to line up the Boron Dilution System when emergency sump recirculation flow is initiated. The permanent procedure changes were implemented on November 5. Subsequently, Design Engineering completed calculations which indicated that the time to reach the solubility limits at Oconee was actually 9 hours. This was longer than the time calculated by B&W.

Previously, the licensee identified and reported by LER 269/90-11, that the Post LOCA Boron Dilution System at Oconee did not meet single failure criteria. The valves on two redundant trains of the Boron Dilution System were powered from the same motor control center. To correct this discrepancy, the power supply for one of these valves, Valve LP-104, was changed to an alternate power supply. This corrective action was also applicable to the resolution of LER 269/91-13.

e. (Closed) LER 269/92-03, Reactor Trip Results from Electrical Generator Lockout After Equipment Failure in a Generator Protective Relay Cabinet. Operations personnel safely controlled the reactor following the trip. Subsequent licensee investigation found that the unit tripped when control power to the relay circuitry was interrupted due to a loose connector pin. The loose connector pin was bypassed and the wiring was hard wired to the terminal block.

Three additional minor problems associated with this event were identified and corrected. Feedwater Suction Relief Valve 1FDW-50 failed to reseat properly after lifting and was replaced. Feedwater Pressure Switch 1PS-419 was found to be out of calibration and was recalibrated. Stator coolant leaked into the Generator Field Rectifier cabinet but was stopped by tightening the insulating tubes. The inspectors verified that these items had been completed.

f. (Closed/Rescinded) LER 269/92-07, Deficiency Leads to TS Violation When an Inappropriate Boric Acid Addition Flow Path Was Used. The LER was issued after the licensee identified that a bleed flush header, associated with the "B" Bleed Transfer Pump flow path, did not appear to be provided with heat tracing. It appeared that this piping was being used as a part of the flow path for the transfer of highly concentrated boric acid. During a subsequent review, after issuance of the LER, the licensee found that the alignment and flow path actually being used by the procedures was adequately heat traced. Further review found no reason to believe that the non-heat traced alignment was ever used. Therefore, by letter dated October 15, 1992, the licensee rescinded this LER.

g. (Closed) LER 269/93-01, Design Deficiency Results in the Technical Inoperability of the Oconee Emergency Power Source Due to a Postulated Failure of Keowee Hydro Units. This problem was discovered during the licensee's ongoing single failure analysis of the Keowee Hydro Station. If a Keowee unit is under a high net head (differential lake elevations) and generating at full load to the system grid when an emergency start is initiated, the emergency start will cause the unit to separate (load reject) from the system and consequently trip on overspeed. This would result in the unit not being available to supply emergency power to the Oconee Station. Administrative procedures were implemented which prohibited the Keowee units from generating to the grid until the problem was resolved.

The inspectors verified that the following corrective actions had been completed:

- An Operability evaluation was completed which indicated that a Keowee unit could generate to the grid at no more than 66 MW with a gross head no greater than 146 feet.

- Procedure OP/0/A/2000/041, Keowee-Mode of Operation, was revised to limit the maximum generation to the grid by a single Keowee unit to 60 MW at a gross head of no more than 146 feet and to prevent the dispatcher from using load control.

- The single failure analysis, Calculation No. OSC-5096, of the Keowee Station was completed on January 21, 1993.

On April 6, 1993, load rejection tests were performed on Keowee. The results of these tests and subsequent Calculation OSC-6003 indicated that a Keowee unit could operate up to a maximum of 75 MW without an overspeed trip concern. A Memorandum to the Keowee

Operators was issued on June 2, 1993, which provided instructions on the new acceptable operating limits for Keowee. However, Procedure OP/0/A/2000/041 was not revised to include this information as required by TS 6.4.1 and Station Directives. Refer to paragraph 7 for additional information on this issue.

h. (Closed) LER 287/91-01, Unplanned Reactor Protective System Actuation During Cooldown and Depressurization Due to Inappropriate Action. During a Unit 3 shutdown for refueling, with three of the four Reactor Coolant Pumps (RCPs) in service, an operator used an inappropriate Reactor Coolant System (RCS) pressure indicator to control the RCS depressurization. As RCS pressure was decreased, one Reactor Protection System (RPS) channel tripped unexpectedly on low RCS pressure followed by a second RPS channel low pressure trip which initiated an RPS actuation. Operations shift personnel continued the cooldown and depressurization of the unit in accordance with the shutdown procedure.

The inspectors verified that the licensee had completed the following corrective action to prevent recurrence:

- Procedure OP/A/1102/10, Unit Shutdown, was revised to go to 2 RCPs at the start of a unit cooldown to minimize RCS loop pressure differences; a "Caution" statement was added which directs operators to monitor RCS Narrow Range pressure points on the Operator Aid Computer since these are inputs to the RPS; and, a change was included to increase the pressure range for inserting Safety Rod Group 1.

- The licensee's management monitored the performance of the operator who caused the transient for several shifts. No additional discrepancies were identified.

- Operators were given additional in-depth training on reactivity management and on cooldown and depressurization of the RCS.

i. (Closed) LER 287/91-02, Loss of Reactor Coolant Inventory Due to Inadequate Procedure and Labeling Policy, Results in Loss of Decay Heat Removal Ability While Shutdown. The LER reported a spill of 14,000 gallons of water from the Reactor Coolant System (RCS) and Borated Water Storage Tank to the Unit 3 Reactor Building floor. A blind flange cover, thought to have been installed on Valve 3LP -19, had actually been installed on valve 3LP-20. The spill occurred when Valve 3LP-19 was manually opened. The loss of RCS was stopped by closing valve 3LP-19. Decay heat removal was re-established by filling the reactor vessel and restarting Low Pressure Injection (LPI) pump 3A.

The inspectors verified that the licensee had completed the following corrective actions to prevent recurrence:

- Identification numbers for Valves LP-19 and LP-20 were painted on the Reactor Building walls in each unit adjacent to the valves.

- Procedures PT/1,2,3/A/0203/04, LPI Leakage, and MP/0/A/1800/105, Reactor Building Emergency Sump LPI Suction Line Flange Installation, Removal and Screen Inspection, were revised to agree with the valve labeling. Also, a diagram of the flanges was added to aid identification.

- Procedure OP/1,2,3/A/1103/11, Drain and Nitrogen Purging of the RCS, was revised to require the Transfer Canal Radiation Monitor to be operable or a suitable portable detector with a local audible alarm to be in place any time the RCS is in a reduced inventory condition.

- Operations and maintenance personnel were given additional training on the use of flow diagrams and electrical drawings.

- Station Directive 3.1.6, Station Labeling, was issued to provide guidance on equipment labeling and the action to be taken for missing or informal labeling. The plant staff was given training on these requirements.

- Communication techniques have been stressed with all plant organizations. For control room communications, the use of repeat back practices has been implemented.

- A training package was routed to all Radiation Protection personnel which emphasized the importance of contacting the control room if an area evacuation is warranted.

No violations or deviations were identified.

7. Keowee Commitments

On March 29, 1993, a management meeting was held at NRC Headquarters for Duke Power Co. to discuss the Oconee Unit 2 loss of power event which occurred on October 19, 1992. The corrective action commitments implemented as a results of this event were also discussed. A list of these commitments was submitted to the NRC by letter dated April 29, 1993. The inspectors reviewed the licensee's corrective action on the following items from this commitment list:

- Switchyard Synchroscope Repair

  The Switchyard synchroscope was repaired and subsequently tested on March 16, 1993 using procedure PT/0/A/0620/17, Keowee Manual Synchronization Test. This procedure tested the manual synchronization function of the Keowee Hydro Units into the system grid across a designated 230 KV switchyard PCB. The inspector reviewed the completed test procedure and had no further questions. This item is closed.

- MG-6 Relay Review for Repair and Preventive Maintenance (PM) Program

The work on this commitment item was in progress at the end of this inspection. Six of the 12 MG-6 relays at Keowee are scheduled to be replaced by July 2, 1993. An evaluation, which is scheduled to be completed in late July 1994, will determine the type and frequency of the preventive maintenance that should be applied to these relays. The evaluation will also determine if any of the relays should be replaced with a relay of a different type design. A review of Units 1 and 2, to identify the location of the MG-6 type relays, was completed during the recent Unit 2 refueling outage. A similar review for Unit 3 is scheduled for early 1994 during the Unit 3 refueling outage. Implementation of this PM program for Keowee, Unit 1 and Unit 2 is scheduled to be complete by late summer 1994. This item will remain open pending implementation of the PM program.

- Keowee Overspeed Switch Setpoint Revision

The licensee reported by LER 269/93-01 that under certain conditions the emergency power supplied by the Keowee Hydro Station to the Oconee Station could be lost. If an emergency start was initiated while a Keowee unit was generating to the system grid at high load, the Keowee unit could trip or load reject on overspeed. To prevent this problem, Procedure OP/0/A/2000/041, Keowee-Mode of Operation, was revised on January 15, 1993, to limit the maximum output of a Keowee Unit generating to the system grid to 60 MW. This was intended to provide some margin to the licensee's analyzed value of 66 MW.

On June 2, 1993, based on the results from load rejection tests performed on April 6, 1993, and on revised calculations which were completed on May 20, 1993, the licensee's Keowee Station Manager issued a Memorandum to the Keowee Operators that increased the maximum permissible output of the Keowee unit generating to the grid. This memorandum specified that the Keowee unit connected to the grid was to be loaded onto the grid at 69 MW. After verifying that the Keowee Lake level and Operating Tailrace level were within the levels specified by the memorandum, generation to the grid could be increased up to a maximum of 75 MW. Operability Calculations OSC-6003 indicate that with a gross head of 134.9 feet, a Keowee unit can reach a maximum overspeed of 172.23 rpm. This is below the overspeed set point of 180 rpm.

Although calculations were performed to verify acceptable operating limits, these operational requirements were not used to revise the controlling operating procedure, OP/0/A/2000/041. These changes were made by a local Keowee Station memorandum. TS

6.4.1 requires the Oconee Station to be operated in accordance with approved procedures. The appropriate review and approval process for major procedure changes are addressed by Administrative Policy Manual for Nuclear Station, Section 4.2.6, and Station Directive 2.2.1, Station Procedures, Section 5.0. The failure to revise this procedure as required is identified as Violation 269,270,287/93-20-03: Failure to Follow Procedures at Keowee.

The inspectors reviewed the Keowee Station operational data from May 1 - June 15, 1993, and noted that the Keowee unit connected to the grid had generated in excess of the 60 MW limit specified by procedure OP/0/A/2000/041 on numerous dates i.e. May 4-6, 10-14, 18, 25, 27, 31 and June 3, 4, 8, and 9. Furthermore, the inspectors noted that the operating Keowee unit on June 8 and 9 operated at 77 and 76 MW respectively. This exceeded the limits established by the Operability Calculations and those specified by the Keowee Memorandum of June 2, 1993. This Memorandum specifically states that "No Keowee unit should be operated above 75 MW". The inspectors reviewed operator logs and did not identify instances where the TS action statement for Keowee Hydro Unit operability was exceeded. The failure to operate the Keowee units in accordance with management established guidelines, even though not included in approved procedures as required, is an indication of a lack of attention to detail by the Keowee operators and is considered a program weakness.

- Keowee Communication Equipment

The available communication equipment at Keowee has been upgraded. A base radio station, equipped with a battery backup power supply, has been provided. The Keowee operator has a portable radio and the base radio is installed in the Keowee control room. These radios can be used for communication with the Oconee control room. The inspectors witnessed tests on both the portable and base radios and verified that communication was available between Keowee and the Oconee control rooms. Operability of these radios is verified each shift.

The former telephone system at Keowee has been replaced with a new system equipped with backup battery power supply. A 100 pair cable has been installed between the Oconee and Keowee Stations. In addition to the regular plant telephone system, a direct connection is provided between the Oconee and Keowee control rooms. However, periodic tests to verify operability of the direct connections between the control rooms are not being performed. The licensee committed to revise procedure OP/0/A/2000/043 to require this direct connection to be tested at least once per day. Implementation of this change will resolve the inspectors' concerns on the reliability of this portion of the communication system.

- Oconee Loss of Power Procedures

  The inspectors reviewed procedure AP/1/A/1700/11, Loss of Power, Section 13.0 and Enclosure 6.8, which have been revised to include the steps necessary to recover offsite power to the Oconee Station. This procedure has also been revised to include both dead bus and live bus transfer options. On March 16, 1993, during performance of procedure PT/0/A/0620/017, Keowee Manual Synchronization Test, the live bus transfer option was satisfactorily functionally tested.

One violation was identified.

8. Exit Interview

The inspection scope and findings were summarized on July 1, 1993, 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
IFI 50-269,270,287/93-20-01	Instrument Impulse Lines and Associated ISI Requirements (paragraph 4).
IFI 50-269,270,287/93-20-02	Review of Piping and Component Code Class Requirements (paragraph 4).
VIO 50-269,270,287/93-20-03	Failure to Follow Procedures at Keowee (paragraph 7).
IFI 50-269/93-20-04	Alarm Circuit/Control Circuit Interface (paragraph 2.d).