UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-269/95-27, 50-270/95-27 and 50-287/95-27

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

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

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

Facility Name: Oconee Units 1, 2 and 3

Inspection Conducted: November 5 - December 16, 1995

Inspectors: RE Carroll for P. E. Harmon — 1/11/96
P. E. Harmon, Senior Resident Inspector — Date Signed

L. A. Keller, Resident Inspector
P. G. Humphrey, Resident Inspector
N. L. Salgado, Resident Inspector
R. E. Carroll, Project Engineer

Approved by: R. V. Crlenjak — 1/11/96
R. V. Crlenjak, Chief — Date Signed
Reactor Projects Branch 1

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, maintenance and surveillance testing, onsite engineering, and plant support. It included an inspection of open items and licensee event reports.

Results:

Operations: One violation for inadequate procedures with two examples was identified. The first example involved a Nuclear System Directive used to determine reportability, paragraph 2.e. The inadequate procedure resulted in a failure of licensee personnel to make a required report per 10CFR50.72. The second example involved a procedure used to establish system boundaries for Block Tagouts, paragraph 2.f. The inadequate procedure resulted in a spill of approximately 350 gallons of contaminated water. A strength was noted regarding the alertness displayed by the operators when a sudden failure of a feedwater regulating valve occurred, paragraph 2c.

ENCLOSURE 2

9601260366 960111
PDR ADOCK 05000269
Q PDR

Maintenance:	Two Non-cited Violation (NCVs) were identified. The first NCV involved an inadequate procedure controlling grinding and burning evolutions which resulted in an unanticipated hydrogen burn of short duration, paragraph 3.a(1). The second NCV involved inadequate procedures for the control of temporary electrical jumpers, paragraph 3.a(9).
Engineering:	Continuing problems were identified in the quality of Keowee Hydro Unit drawings, paragraph 4a.
Plant Support:	A continuing strength was identified for the licensee's efforts to reduce personnel radiation exposure. The Unit 1 refueling outage was completed with several significant goals met or exceeded, paragraph 5a.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

B. Peele, Station Manager
*E. Burchfield, Regulatory Compliance Manager
*D. Coyle, Systems Engineering Manager
*J. Davis, Engineering Manager
T. Coutu, Operations Support Manager
*W. Foster, Safety Assurance Manager
J. Hampton, Vice President, Oconee Site
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Manager
*J. Smith, 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.

*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. Inspectors attended some shift changes 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. During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

Unit 1 remained in a refueling outage until December 10, when the unit was returned to service.

Unit 2 operated at or near full power throughout the reporting period with the exception of one day when the power level was dropped to 90 percent to take the 2B2 waterbox in the main condenser out of service to plug a tube leak.

Unit 3 operated at full power until November 17, 1995, when a feedwater transient resulted in a temporary reduction in power to 75 percent (paragraph 2.c). The unit returned to full power operation that day and remained at full power throughout the rest of the inspection period.

c. Unit 3 Feedwater Transient

At 3:18 P.M. on October 17, 1995, the Unit 3 ICS Tracking Alarm annunciated due to a feedwater cross-limit condition. The operators quickly determined that feedwater valve, 3FDW-41 (main feedwater control valve to the 3B Steam Generator) was going closed and took the ICS controls to manual and stabilized the plant. The operators prompt actions minimized the transient, which if left unchecked could have resulted in a reactor trip.

Traces from the transient monitor were analyzed which indicated that nuclear power had decreased from approximately 100 percent to 75 percent during the transient. An investigation into the transient was conducted but no cause for the valve closure was found. The system was returned to automatic control and operated without further problem throughout the remainder of the reporting period.

The operator alertness and quick response was noted as a strength.

d. Unit 1 Reduced RCS Inventory Operations

The inspectors reviewed the licensee's procedures, back-up power supplies, level indication, core cooling capabilities, and the RCS inventory makeup path availability prior to draining the RCS to install nozzle dams in the steam generators. After the nozzle dams were installed the RCS inventory was raised and was not lowered again until time for the nozzle dam removal. Again the inspectors performed their inspections detailed above prior to the licensee reducing RCS inventory. The inspectors noted that the licensee complied with their program for reduced inventory operation.

e. Inoperable Low Pressure Injection System Train Due To Failed Valve Operator

On November 6, 1995, the licensee aligned the Unit 1 LPI system to perform the "A" LPI Cooler Test in accordance with PT/0/A/251/18, LPI Cooler Test. The test called for 5000-5200 gpm LPSW flow through the secondary side of the "A" LPI cooler (LPSW is the heat sink for LPI). At the start of the test, initial LPSW flow was approximately 2500 gpm, adequate to maintain RCS cooling for the decay heat load that existed at that point in the refueling outage. Several days prior to the event, LPSW flow had been 5000 gpm. When the operator attempted to increase LPSW flow, flow did not increase. The licensee's investigation determined that manual butterfly valve 1-LPSW-254 downstream of the cooler had drifted partially shut when the key that locks the manual actuator to the valve stem had failed. The key was replaced and the valve operated as required.

PIP 1-095-13496 was initiated to evaluate the operability of the LPI system and to determine the cause of the failure. The cause of the failure was determined to be a combination of high piping vibration in the area of the valve, and the design of the key/keyway which allowed the key to move out of the keyway. This same valve had failed during the previous refueling outage for the same reason. After the first failure, the key was replaced and staked in place in an attempt to prevent its movement. At that time, the licensee assumed the failure to be a random, non-repeatable occurrence. As a result of this latest failure the licensee installed a permanent modification on this valve, and the other valves of this design in the LPSW systems (both trains on all three units), that prevents the key from vibrating out of the keyway.

The licensee determined that the situation which produced the high vibration occurred when the LPSW was throttled below approximately 3000 gpm. Operation at the reduced flow rate increases the pipe vibration near 1-LPSW-254. Since emergency procedures require throttling LPSW flow to 3000 gpm during certain accident scenarios, the past operability evaluation declared the "A" train of the Unit 1 LPI system to have been past inoperable from December 3, 1992, (initial installation of the valve) until November 2, 1995. This determination was based on the possible failure of the valve if a LOCA had occurred during that time period. While the valve key might have remained in place and intact, the licensee could not rule out the possibility of the failure occurring.

The past (in)operability evaluation was completed December 7, 1995, 30 days after identification of the original problem on November 6, 1995. The time allowed to make past operability evaluations is consistent with the licensee's corrective action program. Licensee management held a meeting on December 7, 1995, to determine whether a 1-hour or 4-hour report was required under 10 CFR 50.72. The licensee uses NSD 202, 10 CFR 50.72 Reports to assess reportability requirements. After processing the event through the directive, the licensee decided that the event was not reportable under 10 CFR 50.72. The inspector agreed that the conditions of the event did not appear to meet the guidance in NSD 202, and was not similar to the examples or case studies cited in the directive. However, the inspector disagreed with the licensee's decision, and stated that 10 CFR 50-72(b)2.i appeared to apply in this case. 10 CFR 50.72(b)2.i uses as an example for reportability: "any event, found while shutdown, that, had it been found while operating, would have resulted in the plant being in an unanalyzed condition that significantly compromises plant safety." The inspector expressed the opinion that having a train of LPI inoperable for several years was an unanalyzed condition that significantly compromised plant safety.

On December 11, 1995, the inspector discussed the specifics of the event with NRC personnel familiar with reporting requirements. At the same time, the licensee was also reviewing the guidance in NUREG 1022, Rev 1, Draft 2. After reviewing the references, the licensee agreed that a 4 hour report was required. At 4:33 p.m., the licensee made a 4 hour report under 10 CFR 50.72.(b)2.i.

The licensee determined that the NSD had not incorporated the clarifying case study/example from NUREG 1022. Due to this omission, the NSD as written did not lead to the proper conclusion on the reportability of the inoperable LPI train. The failure to make a 4 hour report per the requirements of 10 CFR 50.72 is identified as example 1 of Violation 50-269,270,287/95-27-01, Inadequate Procedures.

In addition to the deficiency noted in the NSD, the inspector informed the licensee that the time allowable to make 1 hour, 4 hour, or 30 day LER Reports as required by 10 CFR 50.72 and 10 CFR 50.73 begins at the time of discovery of the condition or problem, not at the conclusion of the evaluation process. The Oconee Corrective Action Program presently allows an evaluation of present operability of three days, and 30 days for past operability. Per the licensee's program, after the evaluations are completed the times allowed for reporting under 10 CFR begins. At the end of the inspection period, the licensee agreed to review the guidance of NUREG 1022, Draft 2, Rev. 1.

f. Unit 1 Water Spill Due To Inadequate Boundary Tagout

ONS utilizes Block Tagouts during outages or periods of major maintenance to enable multiple work activities within isolation boundaries without separate tagouts for each work order. BTO 10B is used to isolate portions of the HPI system. A section of the HPI system included under BTO 10B includes a letdown relief valve, 1HP-

79. Either 1HP-79 or its downstream isolation valves should be included as an isolation boundary for Block Tagout 10B. Due to a procedural deficiency, neither 1HP-79, nor its downstream isolation valves, were included as an isolation boundary for BTO 10B during the Unit 1 refueling outage. Consequently, when 1HP-79 was removed for maintenance during the outage a breach in the BTO isolation boundary was created.

On November 20, 1995, the licensee was filling the HPI system letdown filters via the 1A BHUT Pump when flooding was detected in the LDST room. The licensee determined that the water was exiting the HPI system piping where 1HP-79 had been removed. The discharge line associated with 1HP-79 ties to the 1A BHUT Pump recirculation line. Therefore when the 1A BHUT Pump was started, with 1HP-79 removed, an open flow path between the 1A BHUT Pump discharge and the LDST room existed. NLOs in the LDST room immediately detected the flow of water from the 1HP-79 opening and the 1A BHUT Pump was stopped. Approximately 350 gallons of contaminated water from the 1A BHUT was spilled into the LDST Room.

During a review of this spill event, the inspectors learned that 1HP-79 should have been included as a boundary valve in BTO 10B. The inspectors reviewed the applicable BTO procedure and found that an "Information To User" notation stating that "if work is required on 1HP-79, the downstream valves must be tagged" was omitted in the last revision of the procedure. Failure to include either 1HP-79, or its downstream isolation valves, as a boundary valve in BTO procedure, OP/1/B/1502/08, Enclosure 4-10B, BTO Tagout 10B-HPI Makeup/Seal Injection/Seal Return is identified as example 2, of Violation 269,270,287-95-27-01, Inadequate Procedures.

g. Rod Drop Testing

The inspectors reviewed the results of the rod drop timing test for Unit 1. All rods dropped within the TS time limit. During the outage, a total of 19 rods were refurbished. The rods were refurbished to prevent sticking check valves in the rod housing thermal barrier from slowing the rod drop times.

Within the areas reviewed, a violation with two examples was identified for inadequate procedures. The first example involved a NSD used to determine reportability. The inadequate procedure resulted in a failure of licensee personnel to make a required report per 10CFR50.72, paragraph 2.e. The second example involved a procedure used to establish system boundaries for Block Tagouts, paragraph 2.f.

3. Maintenance and Surveillance Testing (62703 and 61726)

a. Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures adequately described work that was not within the skill of the craft. Activities, procedures and work orders were examined to verify that proper authorization and clearance to begin work was given, cleanliness was maintained, exposure was controlled, equipment was properly returned to service, and limiting conditions for operation were met.

Maintenance activities observed or reviewed in whole or in part were as follows:

(1) Hydrogen Burn Inside Containment

On November 10, 1995, while Maintenance was penetrating the one inch piping associated with the reactor vessel head vent valve, 1RC-160, a small hydrogen fire burned for approximately three minutes. The piping was being cut to allow for removal of valve 1RC-160 in order to repair a seat leak. The vessel head was off during the performance of this maintenance activity.

Maintenance was utilizing an air grinder to cut into the pipe per WO 94033734-03 in accordance with procedure MP/0/A/1810/014, Valves and Piping, Welded- Removal and Replacement - Class A Through F. When Maintenance breached the pipe, a blue flame (hydrogen) burned for approximately three minutes. The RP personnel detailed to accompany Maintenance immediately stopped the job, and advised Maintenance to contact the CR. The Operations staff in the CR advised Maintenance to stop work and watch the flame from a safe distance. During the conversation between Maintenance and CR Operations personnel, the blue flame extinguished. At which time the CR Operations staff provided the consent to continue work. RP refused to permit work to continue, coincident with the WCC personnel who were already evaluating work contingencies. The inspectors verified that WCC personnel had evaluated if other work was being conducted in containment that needed to be halted. The licensee's evaluation concluded that no other work involving grinding, welding, etc., was being conducted in containment. After a thorough work contingency evaluation conducted by Maintenance and WCC personnel, it was determined that work could continue if Maintenance utilized a gas monitor for detecting hydrogen as work progressed. After the pipe was removed the line was sampled again, and hydrogen was present inside the pipe, but not at the opening of the pipe. The licensee generated a PIP, 1-095-1428 to address this problem.

Maintenance used procedure, MP/0/A/1810/014, for performing the work. The procedure did not contain steps for venting or purging the line on which maintenance was being performed, and did not document cautions/requirements for Maintenance to sample or monitor for combustible gases such as hydrogen when working on certain systems/components. Prior to the end of this inspection period, the licensee had revised the associated procedure to incorporate appropriate precautions about combustible gases including the requirement to check for combustible gas prior to welding or performing any spark producing work such as grinding when working on certain systems. Also the licensee will be enhancing the Welder Continuing Training to include the subject of PIP 1-095-1428 and other OEPs concerning hydrogen fires. This licensee-identified and corrected violation is being treated as a NCV, consistent with Section VII-B.1 of the NRC Enforcement Policy. It is being documented as NCV 50-269,270,287/95-27-02, Hydrogen Burn.

The inspector concluded that CR Operations staff did not act conservatively by providing consent to continue work. However, the WCC staff and RP adequately addressed the problem.

(2) Containment Foreign Materials Exclusion

NRC Inspection Report 50-269,270,286/95-12 noted that clear plastic wrap and clear plastic bags were being used extensively in the reactor containment building. This material was utilized for carrying tools and materials in and out of the building. Green and yellow bags and protective plastic materials were mentioned as the industry standard that are used inside the containment because the clear materials are difficult to detect once they have been dropped into water (i.e. refuel canal, reactor vessel). The inspection report documented the use of clear plastic as a weakness in the licensee's program. As a result, the licensee committed to discontinue the use of clear plastic inside containment and near the SFPs, but stated that this may not be achieved for the Unit 1 RFO which occurred during this reporting period.

The inspectors toured the Unit 1 Reactor Building at various times during the RFO. During a tour on November 20, 1995, the inspectors noted that clear plastic had been used to wrap the temporary barrier installed around the reactor head stand, clear plastic bags had been used for the scaffold fittings, and the incore instrument tubing had been brought into the reactor building wrapped in clear plastic. However, clear plastic was not used as extensively as during the previous outage.

The inspectors will continue to perform reactor building and SFP inspections for clear plastic and other potential foreign material hazards.

(3) Inspection and Maintenance of the 1TD Metal-Clad Switchgear, WO 95062233

On November 14, 1995, the inspector observed maintenance activities performed on the 1TD Metal-Clad Switchgear. The activity was performed in accordance with procedure, IP/0/A/2001/003A, Inspection and Maintenance of ITE Type HK Metal-Clad Switchgear, Associated Bus and Disconnects. The inspector determined that this maintenance activity was satisfactorily performed.

(4) Installation of Bypass Around LPSW-139, WO 94080861

On November 13, 1995, the inspector observed ongoing activities associated with the installation of a bypass around LPSW-139 for NSM ON-52972, LPSW-139 Bypass Line. The modification installed a supply path independent of LPSW-139, to the LPSW non-essential header. The new valve is seismic and in full compliance with GL89-10 testing requirements.

The inspector attended a pre-job briefing on NSM ON-52972, 24" Wet Tap Assembly. The briefing covered the work plan, concerns, and work contingencies should problems arise. The inspector observed the cutting of the wet tap, the removal of the coupon, and other miscellaneous activities associated with this work order. The inspector concluded that this activity was satisfactorily performed.

(5) Replace Main Steam Turbine Bypass Valves, WO 9500430

On November 14, 1995, the inspector observed activities in progress during the implementation of NSM, ON12903. This modification replaced the Unit 1 main steam manual isolation and control bypass valves. In addition, the pipe supports and restraints were being replaced as necessary to support the changes in sizes and weight. The valves being replaced had been leaking and resulted in a reduction in plant efficiency. The inspector concluded that the work observed was performed to acceptable standards.

(6) RPS Channel "C" Flow Instrumentation Calibration, WO 95039724

On November 14, 1995, the inspector observed activities in progress during the calibration of the Unit 1, channel "C" reactor coolant flow. The effort was performed in accordance with procedures: IP/0-0/A/0305/015, Nuclear Instrumentation RPS Removal From And Return To Service For Channels A,B,C, And D and IP/0-0/A/0305/001K, Reactor Protective System Channel "C" RC Flow Instrument Calibration. The inspector observed that the work was performed to acceptable standards and documentation was current.

(7) Perform Electrical and Mechanical PM on 1-FDW-40 Operator, WO 95053379

On November 14, 1995, the inspector observed PM on 1-FDW-40. The effort reviewed was performed in accordance with IP/0/A/3001/001, Limitorque Electrical Preventative Maintenance and was properly performed and documented.

(8) Perform PM On 1DID Inverter, WO 95039850

On November 16, 1995, the inspector observed maintenance activities in progress on the 1DID Inverter. The effort was performed per IP/0-0/A/301/001B, Vital Inverter Maintenance Procedure, and was in accordance with acceptable standards.

(9) Temporary Jumper Installed On Keowee Unit 1 Overhead Breaker

On November 21, 1995, the licensee discovered a temporary, alligator clip type jumper installed on control circuitry for ACB-1, the breaker connecting Keowee Unit 1 to the overhead power path. The licensee's Maintenance Directive allows temporary jumpers to be used only while under direct control, such as during testing. All other instances require a permanent, lug-type jumper to be used. The temporary jumper had been installed during NSM 52966, a station modification intended to restore the Keowee units' ability to generate to the utility's commercial grid. The jumper was installed to bypass new circuitry which was not ready for testing. The jumper, as installed, would allow ACB-1 to be returned to operable status. Without the jumper in place, ACB-1 would not close automatically to connect Keowee Unit 1 to the overhead path.

The temporary jumper was noticed by a technician at Keowee during routine rounds. The jumper connection was checked for confirmation of continuity, and then replaced with a permanent jumper. The continuity check was performed to prove that the jumper, as installed, was properly attached and would have performed its function. The technician notified Engineering for evaluation. The Engineering evaluation, performed under PIP 95-1507, concluded that the breaker was presently operable based on the fact that Keowee Unit 1 was aligned to the Underground path. A past operability evaluation was initiated to determine if the breaker would have functioned during seismic and other events during the time Keowee Unit 1 had been aligned to the overhead path. The licensee determined that since a concurrent LOOP/seismic event is not considered a part of the Oconee design basis, the breaker was past operable.

The licensee initiated corrective action to improve controls of temporary jumpers. These included revising Maintenance Directive 4.4.10, Methods For Installing Temporary Electrical Jumpers. The revised directive will include provisions for controlling the issuance of jumpers from an appropriate issue center, which will require specific, procedure directed jumper identification.

This licensee-identified and corrected violation is being treated as a NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. It is identified as NCV 50-269,270,287/95-03, Inadequate Jumper Control Procedures.

b. The inspectors observed surveillance activities to ensure they were conducted with approved procedures and in accordance with site directives. The inspectors reviewed surveillance performance, as well as system alignments and restorations. The inspectors assessed the licensee's disposition of any discrepancies which were identified during the surveillance.

Surveillance activities observed or reviewed in whole or in part are as follows:

(1) Unit 1 EPSL Functional Test, PT/1/A/0610/01J

On November 24, 1995, the inspector witnessed performance of the Unit 1 EPSL functional test. This test is conducted every refueling outage and is used to meet TS surveillance requirements 4.6.2 and 4.6.4. Additionally, the test was revised to include additional testing in order to gather data to validate the licensee's model of standby bus voltage/frequency under certain scenarios. The additional testing included loading approximately 2 MVA on the KHU eleven seconds after the start signal while the unit was still accelerating and at 55 percent voltage and frequency. This is the point where LOCA loads would be loaded following a LOCA/LOOP. The licensee's calculations assume that following a LOCA/LOOP, the KHU aligned to the underground path would experience approximately 33 MVA in-rush and 7 MVA steady state demand from accident mitigation equipment. This test, though not bounding, was intended to provide data to validate the licensee's model which indicated that voltage and frequency remained at an acceptable level following a DBA. Additionally, the test sequentially loaded on three CCW pumps, after the KHU was at steady state conditions, then simultaneously shed two of the CCW pumps. This portion of the test was to demonstrate the KHU governor and voltage regulator response to load swings.

The inspector noted that there were no adverse equipment responses during these portions of the test. As of the end of the inspection period, the licensee was still analyzing the test data to determine if it validated their model.

The test was conducted in accordance with procedures and with one exception all the acceptance criteria were met. The one exception was the requirement for the feeder breaker (1TE) for load center 1X7 to reclose onto the Unit 1 main feeder bus between 57 and 63 seconds (60 +/- 5%) after the KHU emergency start signal. During the test the breaker did not reclose until 65 seconds after the start signal. The 60 second time delay is obtained through an Agastat (E7012PE004) timing relay. From a design basis, any time greater than 40 seconds delay following load shed is adequate. Therefore the licensee concluded that this particular test deficiency did not represent a past operability concern. A work request was initiated to recalibrate the relay back to 60 seconds. The inspectors reviewed all the other Agastat relay applications at Oconee and determined that there was not a generic problem with the application of Agastat relays.

(2) HPI Full Flow Test, PT/1/1A/251/24

The inspector observed the performance of surveillance PT/1/A/251/24, HPI Full Flow Test. The test method established flow through the "A" and "B" trains of the LPI to HPI and the "A" and "B" trains of HPI to the RCS to verify proper operation of the check valves in each flowpath. Additionally, the HPI suction check valves from the BWST and all three HPI pump discharge check valves were tested.

During the performance of Step 2.25, which involved throttling open 1HP-26, the pressurizer level began to decrease with a corresponding increase in reactor building normal sump level. The licensee concluded that the source of the leak was 1HP-323, a one-inch drain valve which had vibrated open during the full flow conditions developed from the full flow test. It was noted that the 1HP-323 pipe cap had also vibrated off. The licensee suspended the test and closed and capped 1HP-323. A total of 2345 gallons of make-up was required to recover pressurizer level to 100 inches. The licensee generated a PIP 1-095-1563 to resolve this issue.

As recorded on the procedure's Enclosure 13.4 data sheet, the 1A HPI pump developed head was 1130 psid. This value did not meet its acceptance criteria for the low side of the band, which was 1189 psid. The licensee performed an engineering evaluation to address this problem. The licensee's evaluation concluded that the HPI pumps have experienced over time a gradual decline in total developed head at high flow. The licensee's evaluation determined normal wear of the running clearances within the pump would account for the decrease in the range of 2-3.5 percent per cycle. The licensee's evaluation concluded that the 1A HPI pump would fulfill its design basis requirements for Unit 1 Cycle 17. The PIP documented that the licensee would be monitoring and trending the future Unit 1 HPI System Full Flow Tests. The PIP also documented that if significant degradation is detected on the 1A pump, based on trend results, further analysis will be performed. If the analysis determines that maintenance is required, the pump will be replaced with a spare pump. The inspector will follow future testing of the 1A HPI pump. The licensee actions were adequate in addressing this problem.

(3) Unit 3 Control Rod Movement Test, PT/3/A/600/15

On November 16, 1995, the inspector observed the monthly control rod movement test from the Unit 3 Control Room. The inspector noted that the control room operators reviewed the test procedure before beginning the test and questioned the difference between the 2.5 percent movement for the Unit 3 rods and the 10 percent movement on the Unit 1 & 2 rods. The operators researched the question and determined the difference was due to problems with sticking ball check assemblies in the Unit 1 & 2 control rod drive assemblies requiring greater rod movement in order to flush out the ball check area. Due to differences in design, the Unit 3 rods did not require the additional movement. The inspector considered the operator's actions to be a positive example of a questioning attitude.

Within the areas reviewed, two NCVs were identified.

4. Onsite Engineering (37551)

During the inspection period, the inspectors assessed the effectiveness of the onsite design and engineering processes by reviewing engineering evaluations, operability determinations, modification packages and other areas involving the Engineering Department.

a. Keowee Drawing Inspection

On November 8, 1995, the inspectors conducted an inspection of KHU logic cabinets 1LC1 and 1LC2 in order to compare the connection diagram drawings with the as-built configuration. These two cabinets were selected at random and are representative of numerous electrical cabinets at Keowee. The inspectors noted the following discrepancies between the drawings and the as-built configuration:

1) The drawings (K-713-A & K-713-B) indicated that safety-related circuit wires are taped every ten inches (grey tape for Unit 1 and yellow tape for Unit 2). There were 14 examples where the drawing indicated a wire was taped where there was no tape on the wire.

2) Cabinet 1LC1, terminal strip TB-7, had two link positions that were not labeled whereas drawing K-713-A indicated that these links were designated 52ITD7 and 52ITD7A.

3) Cabinet 1LC1, terminal strip TB-6, had two links where the designation in the cabinet was different from that on the drawing (99SX1-3 vs 41C1, 99SX1-3A vs 41C8).

4) Cabinet 1LC1, terminal strip TB-4, had two locations (4B-4C & 4B-4Ca) where the drawing indicated there was a wire connected to the left hand side of the terminal strip where there was no wire.

5) Cabinet 1LC1, terminal strip TB-3, had a 3000 ohm resistor whereas drawing K-713-A indicated the resistor was 6800 ohms.

6) Cabinet 1LC1, terminal strip TB-2, had a link (1CP) with two wires on the left hand side of the link whereas the drawing indicated three wires.

7) Relay 52-1TD was wired differently than indicated in the drawing.

8) Drawing K-713-A indicated that there was a link designated 62B1 in cabinet 1LC1, terminal strip TB-1, whereas this link designation did not appear in the cabinet.

9) Cabinet 1LC2, terminal strip TB-14, link location 86N had 3 wires on the left hand side and 3 wires on the right hand side, whereas the drawing indicated 4 on the left and 2 on the right.

10) Cabinet 1LC2, terminal strip TB-13, did not have a wire on the right hand side whereas drawing K-713-B indicated a wire on the right hand side.

11) Cabinet 1LC2, terminal strip TB-11, had two locations (74F-2F & 74F-2Fa) where the drawing indicated a wire on the right hand side where there was no wire.

12) Cabinet 1LC2, terminal strip TB-9, location 1C17 had 2 wires on the right hand side where the drawing indicated only one wire.

13) For relays 65SX and 65SY the drawing indicated a wire was connected to contact 1 whereas the wire was actually connected to contact 3.

The licensee initiated PIP 0-095-1461 to disposition these discrepancies. The licensee subsequently determined that the discrepancies were of an editorial nature and did not represent an operability concern. The licensee determined that most of the discrepancies had been identified during walk downs conducted in 1993 as a result of previous drawing problems (PIP 4-092-0301). However, eight of the discrepancies had not been previously identified. In order to determine if drawing discrepancies were a concern in other Keowee cabinets, the licensee inspected four additional cabinets (1MTC2,CB2,2LC1,2MTC1). This inspection revealed additional discrepancies of an editorial nature that had not been previously identified. The results of these latest NRC and licensee inspections indicate that the licensee's previous inspections were inadequate.

On July 16, 1992, Keowee drawing problems were discovered which led to the initiation of PIP 4-092-0301. As part of the corrective action for this PIP, the licensee conducted inspections of all the Keowee electrical cabinets. These licensee inspections, conducted during 1993, resulted in the generation of numerous red marked drawings. The majority of these red marked drawings were entered into the licensee's editorial change process for resolution. The editorial change process did not have any time requirements for issuance of corrected drawings. NRC Inspection Report 50-269,270,287/95-20 identified a weakness in the licensee's program for correcting drawing deficiencies in that known drawing errors could exist indefinitely for safety-related drawings.

As part of the licensee's Emergency Power Upgrade Project (Item # 114), all known Keowee drawing discrepancies were to be corrected and correct drawings issued no later than November 1, 1995. The inspectors questioned why Item # 114 was shown as complete on the licensee's project schedule when the majority of the red marked drawings had not been corrected. The licensee stated that due to miscommunication between the licensee's project manager and the individual assigned this task, the task was erroneously closed.

The inspectors were concerned with the quality of the Keowee drawings and the apparent lack of management ownership for this important aspect of design control for the emergency power source. The inspectors noted that little was done to eliminate the backlog of drawing discrepancies identified during 1993. Additionally, the thoroughness and adequacy of the licensee's original inspection was questionable given the results of these latest inspections. The inspectors noted that the licensee was in the process of planning and implementing a very complicated modification to enable simultaneous generation of both Keowee units to the commercial grid. The Engineering and I&E personnel planning and implementing this modification would use these drawings extensively. The inspectors noted that confusion over a drawing discrepancy contributed to time delays that resulted in exceeding a LCO during a previous attempt to implement this modification.

In response to these concerns the licensee suspended all modification activities at Keowee affecting electrical cabinets/wiring until January 1, 1996. During this hold period all known drawing errors would be resolved and corrected drawings issued. The licensee stated that these corrected drawings will be reverified against the as-built configuration as the drawings become available. The inspectors considered these short term corrective actions adequate.

The inspectors concluded that the Keowee electrical drawings inspected were of relatively poor quality. However, the licensee's corrective actions should correct the drawing errors and prevent erroneous information from adversely affecting modification work at Keowee.

b. Unit 1 Component Cooling Spill

The licensee reported a CC water leak during system filling and startup due to relief valve 1CC-43 opening and spilling approximately 2300 gallons of demineralized water into the Unit 1 containment. The system operates at approximately 125 psig and during the refueling outage, the valve was set to relieve at 100 psig. This resulted in the relief valve lifting when the system came up to operating pressure.

The licensee indicated that the 100 psig setting was obtained from the data plate attached to the valve. The licensee stated that a controlled setpoint document has not been maintained for relief valves at ONS. A PIP was generated by the licensee to disposition the miss-set relief valve and to evaluate the need for incorporating relief valve settings into a setpoint document. The inspector concluded that the licensee's proposed corrective actions were adequate. The issue will be reviewed during future routine inspections.

Within the areas reviewed, an inspection of the KHU drawings revealed that the drawings were of relatively poor quality, paragraph 4.a. All other activities observed were satisfactory.

5. Plant Support (71750)

The inspectors assessed selected activities of licensee programs to ensure conformance with facility policies and regulatory requirements. During the inspection period, the following areas were reviewed:

Radiological Controls, Physical security and Fire protection.

a. Unit 1 Refueling outage

Unit 1 EOC 16 refueling outage was completed on December 10, 1995. The outage length of 38 days was the shortest refueling outage ever for Oconee. Configuration control improved during the refueling outage, with a single error occurring during a BTO evolution, paragraph 2.f. There were no Human Performance errors resulting in LER events. In another outage-related area, the volume of radwaste generated was reduced to approximately half that of previous outages.

A total of 73 REM of radiation dosage was accumulated for the outage. This was considerably below the previous best of 112 REM. The dose reduction was primarily a combination of continuing efforts at source reduction (RCS crud burst and cleanup at the beginning of the outage) and other ALARA initiatives. The licensee believes the placement of additional lead shielding was a major contributor to the dose reduction. The inspectors consider that the dose reduction efforts during this outage and the previous, Unit 3 outage, constitute a continuing strength in the ALARA program at Oconee.

b. Containment Closure Inspection

On December 8, 1995, the inspector toured the Unit 1 Reactor Building to determine if outage related work items (scaffolding, welding rigs, portable power supplies, etc.) were removed prior to Unit 1 going online. The inspector looked closely for any material that could potentially clog the emergency sump during an accident. With only a few minor exceptions, the reactor building was ready for power operation. All discrepancies were immediately corrected.

Within the areas reviewed, licensee activities were satisfactory.

6. Inspection of Open Items (92901)

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

a. (Closed) Violation 50-269,270,287/95-06-01, Inadequate Corrective Action for Control of Keowee Operating Limits

On June 2, 1993, the licensee's Keowee Station Manager issued a memorandum to the Keowee Operators that raised the maximum permissible output of the Keowee unit generating to the grid, from 68 to 75 MW. Although calculations were performed to verify maximum load limits, the controlling procedure, OP/0/A/2000/041 was not revised. As a result, the Keowee units were operated for a period of time in excess of the official limit. The failure to revise this procedure was identified as Violation 50-269,270,287/93-20-03: Failure to Follow Procedures at Keowee.

The 75 MW limit was later found to be in error by NRC reviewers and revised to 69 MW maximum. To ensure the 69 MW limit would not be exceeded due to the expected unit swing, an operational limit of 64 MW was imposed.

On March 15, 1995, the licensee revised calculation OSC-6003, "Keowee Operating Limits to Prevent Overspeed Due to Load Rejection," to change the maximum operating limit for a Keowee Hydro Unit generating to the grid from 69 to 68 MW. Upon revising this calculation, the responsible engineer called Keowee Hydro Operations and advised them of the analysis results which changed the administrative operating limit from 64 to 63 MW. The Keowee operator agreed that the unit would be run at 63 MW or less until the procedure was changed (procedure limit was 64 MW). The procedure was changed on March 20, 1995. The resident staff reviewed the Keowee Operating Log for the period of March 15 - 20, 1995, and noted that on March 16 & 17, 1995, a Keowee Hydro Unit was operated at 64 MW. The inspectors concluded that attempting to change a Keowee operating limit based on a phone conversation between a system engineer and a Keowee operator was both inappropriate and ineffective, in that it did not include the proper chain of command and did not achieve the desired result. The inspectors concluded that this was similar to Violation 93-20-03 in that the operating limit was inappropriately changed (the first time by memo, the second time by phone). Both the engineer involved and the Keowee operators treated this issue as a Keowee issue rather than an Oconee issue. As a result, the Oconee shift supervisor was not contacted concerning the new limits. Keowee operations and chain of command has officially been integrated into Oconee Operations, but this incident indicated further efforts were needed.

The licensee's corrective actions included:

(1) Implementation of a formal means for Oconee Nuclear Site Engineering to inform the Operations Shift Manager of changes in operability of station equipment.

(2) Operations Management Procedure 5-2, Duties and Responsibilities of Keowee Station Personnel, was changed to require immediate notification of the Operations Shift Manager of a change

in Keowee Hydro Unit operability, determined by Keowee operations personnel.

(3) Operations Management Procedure 5-3, Emergency Power System, was changed to include the requirement that Keowee safety system operating limits will not be established by phone communication, memos, or letters.

(4) Operations management met with each Keowee Station operator to emphasize that informal communications such as phone communications, letters, or memos were not to be used in place of procedures for safety system operation.

The inspector verified that items 2, 3, and 4 were completed. Item 1 was still under development with a due date of January 30, 1996. The inspector interviewed several Keowee operators and determined that they were aware of the procedural guidance and management expectation regarding control of Keowee load limits and other changes that affect operability. The inspector concluded that the corrective actions implemented should be adequate to prevent recurrence. Based on this review, violations 50-269,270,287/93-20-03 and 50-269,270,287/95-06-01 are closed.

b. (Closed) Violation 50-269,270,287/93-20-03, Failure to Follow Procedures at Keowee

This violation was repeated as violation 50-269,270,287/95-06-01 which is discussed and closed in paragraph 6.a, above.

c. (Closed) Violation 287/94-16-02, Failure to Follow Procedure Results in Inadvertent Dilution of the Reactor Coolant System

On May 23, 1994, Unit 3 experienced an inadvertent 6 ppm reactor coolant system deboration. This event occurred when the balance of plant operator mistakenly utilized the 3A (non-boron saturated) deborating demineralizer for de-lithiation of the RCS rather than the chemistry designated 3B (boron saturated) deborating demineralizer. Observing the resultant automatic control rod insertion, operators determined the cause and terminated the RCS deboration before rod insertion limits were exceeded.

Corrective actions included: (1) counselling the balance of plant operator on adequate STAR (<u>S</u>top, <u>T</u>hink, <u>A</u>ct, <u>R</u>eview) self-checking techniques; (2) counselling the control room senior reactor operator on the importance of staying involved in control room activities; and (3) conducting lessons learned training. The inspector confirmed that this event and associated lessons learned were discussed with all operating shifts. As such an event has not recurred, the inspector considers the corrective actions to be appropriate. Accordingly, this violation is closed.

7. 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, 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 are closed:

a. (Closed) LER 287/94-03, Reactor Trip On Loss Of Main Feedwater Due To Equipment Failure

On August 12, 1994, while returning to full power operations, Unit 3 underwent an anticipatory reactor trip from 42 percent power due to the loss of its only in-service main feedwater pump (3B). The root cause of the trip was a failure of the gasket which is located between the relay valve and the emergency governor lockout valve in the 3B main feedwater pump front standard oil tank. The gasket failure/degradation allowed the hydraulic oil to bypass the normal flowpath and return to the tank. As the feedwater pumps utilize hydraulic logic, the gasket leak ultimately caused the 3B main feedwater pump turbine to reduce its output to the low speed stop. At the time of this event, gasket replacement and/or testing was not required as a routine preventive maintenance item.

The inspector verified that maintenance procedures MP/0/B/1320/013, Pump - Feedwater - Turbine - Front Standard - Preventive Maintenance Of Hydraulic Control Oil System, and MP/0/B/1320/002, Turbine - Feedwater - Overspeed And Lubrication Systems - Operational Test, were revised with instructions to replace the relay valve/emergency governor lockout valve gasket and monitor gasket integrity (hydraulic oil pressure) during overspeed testing. Through a review of completed work orders, the inspector verified that gasket replacement/testing was accomplished on main feedwater pumps 3A, 3B, 2A, and 2B. Since gasket replacement/testing on the Unit 1 main feedwater pumps is scheduled for the current Unit 1 EOC 16 refueling outage, this LER is considered closed.

b. (Closed) LER 270/94-02, Reactor Trip On Sequential Loss Of Both Feedwater Pumps Due to Equipment Failure

While at full power on April 6, 1994, Unit 2 automatically ran back to 54 percent power when the 2B main feedwater pump tripped on low oil pressure. Control of the 2A main feedwater pump was erratic, causing feedwater oscillations. The 2A pump subsequently tripped on high discharge pressure, resulting in an anticipatory reactor trip due to the loss of both main feedwater pumps. Investigation into the cause of the main feedwater pump trips revealed stripped main shaft oil pump gears on the 2B pump and a loose motor gear unit set screw on the 2A pump. The discovery of an improperly torqued main shaft oil pump driver gear locknut and a stock (non-fitted) shaft-to-gear key on the 2B main feedwater pump, made it apparent that not all applicable vendor Technical Information Letters had been incorporated into the licensee's preventive maintenance procedure (MP/0/B/1320/013, Pump - Feedwater - Turbine - Front Standard - Preventive Maintenance Of Hydraulic Control Oil System).

The inspector verified that MP/0/B/1320/013 was revised as committed to specify the torquing of locknuts to the required value, utilization of machine fit keys, and the staking of the motor gear unit set screw. Through a review of completed work orders, the inspector verified that this specified maintenance was performed on all three units' main feedwater pumps. In addition, under the vendor's recommendation, the main shaft oil pump driver and driven gears have since been ordered/replaced by the licensee as a matched set. Confirming that the licensee performed a review of all related main feedwater pump Technical Information Letters to ensure they're encompassed by current procedures, the inspector considered this LER to be closed.

c. (Closed) LER 270/93-02, Loss Of Air Testing For Accumulator Valves Not Performed Per SOER 88-1

NRC GL 88-1 recommended that check valves on safety-related accumulators be tested to verify that they will fully close (with less than allowable leakage) in situations including both rapid and gradual loss of instrument air pressure. The licensee completed their evaluation on June 10, 1993, which revealed that containment integrity could be lost during a postulated loss of instrument air coincident with a small break loss of coolant accident because Unit 2 and 3 HP-21 valves may return to the open position due to accumulator leakage. In addition, it was determined that these valves may have been inoperable in the past and as a result, the licensee committed to replace valves HP-5 and HP-21 on Units 1, 2, and 3 with valves and operators that close on spring pressure as opposed to air pressure.

The licensee has completed the replacement of HP-21 for Units 1, 2, and 3 and HP-5 for Unit 1. The replacement for HP-5 for Units 2 and 3 is scheduled for their next refueling outage. Therefore the LER is closed based on the valves that have been replaced and the licensee's commitment and schedule for replacement of those remaining, HP-5 for Units 2 and 3.

8. Exit Interview

The inspection scope and findings were summarized on December 20, 1995, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings addressed in the Summary and listed below. No dissenting comments were received from the licensee. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Status	Description and Reference
Violation 269,270,287/ 95-27-01	Open	Inadequate Procedures, Two Examples (paragraph 2.e & 2.f)
NCV 269,270,287/ 95-27-02	Closed	Hydrogen Burn (paragraph 3.a(1))
NCV 269,270,287/ 95-27-03	Closed	Inadequate Jumper Control Procedures (paragraph 3.a(9))
Violation 269,270,287/ 95-06-01	Closed	Inadequate Corrective Action for Control of Keowee Operating Operating Limits (paragraph 6.a)
Violation 269,270,287/ 93-20-03	Closed	Failure to Follow Procedures at Keowee (paragraph 6.b)
Violation 287/94-16-02	Closed	Failure to Follow Procedure Results in Inadvertent Dilution of the Reactor Coolant System (paragraph 6.c)
LER 287/94-03	Closed	Reactor Trip On Loss Of Main Feedwater Due To Equipment Failure (paragraph 7.a)
LER 270/94-02	Closed	Reactor Trip On Sequential Loss Of Both Feedwater Pumps Due to Equipment Failure (paragraph 7.b)
LER 270/93-02	Closed	Loss Of Air Testing For Accumulator Valves Not Performed Per SOER 88-1 (paragraph 7.c)

9. Acronyms

ACB	Air Circuit Breaker
ALARA	As Low As Reasonably Achievable
BHUT	Bleed Holdup Tank

BTO	Block Tagout
BWST	Borated Water Storage Tank
CFR	Code of Federal Regulations
CC	Component Cooling
CCW	Condenser Circulating Water
CR	Control Room
DBA	Design Basis Accident
EFW	Emergency Feedwater
EPSL	Emergency Power Switching Logic
EOC	End Of Cycle
ES	Engineered Safeguards
FDW	Feedwater
GL	Generic Letter
GPM	Gallons Per Minute
HP	Health Physics
HPI	High Pressure Injection
ICS	Integrated Control System
I&E	Instrument & Electrical
IR	Inspection Report
KHU	Keowee Hydro Unit
LDST	Letdown Storage Tank
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss Of Coolant Accident
LOOP	Loss Of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MP	Maintenance Procedure
MVA	Mega Volts-Amps
MW	Megawatts
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NSM	Nuclear Station Modification
NSD	Nuclear System Directive
ONS	Oconee Nuclear station
OEP	Operating Experience Program
PSID	Pounds Per Square Inch Differential
PSIG	Pounds Per Square Inch Guage
PM	Preventive Maintenance
PIP	Problem Investigation Process
RCS	Reactor Coolant System
REM	Roentgen Equivalent Man
RPS	Reactor Protection System
RFO	Refueling Outage
SOER	Significant Operating Event Report
SFP	Spent Fuel Pool
TS	Technical Specification
WCC	Work Control Center
WO	Work Order