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

Report Nos.: 50-269/91-09, 50-270/91-09 and 50-287/91-09

Licensee: Duke Power Company
P. O. Box 1007
Charlotte, NC 28201-1007

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: March 24 - April 27, 1991

Inspectors: PKShemanski for 5/2/91
R. B. Desai, Resident Inspector Date Signed

PKShemanski for 5/2/91
W. K. Poertner, Resident Insp tor Date Signed

Approved by: GABelisle 5/3/91
G. A. Belisle, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved inspection on-site in the areas of operations, surveillance testing, maintenance activities, installation and testing of modifications, and inspection of open items.

Results: One apparent violation, with two examples, was identified concerning high pressure injection crossover flow paths. The licensee identified that one flowpath in both Units 2 and 3 had been inoperable for extend periods of time (paragraph 2.c). This item is being reviewed for escalated enforcement action.

A violation was identified associated with failure to follow procedures that resulted in two Low Pressure Service Water (LPSW) valves being out of their required positions, paragraph 2.g.

A weakness was identified in the operations training package associated with the Diverse Scram System (DSS) modification package in that operations personnel did not fully understand operation of the DSS with respect to returning the system to service, paragraph 2.e.

A concern was expressed to licensee management with respect to securing Keowee personnel for the night prior to rewatering the Keowee units during the dual Keowee unit planned maintenance outage, paragraph 2.i.

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REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *H. Barron, Station Manager
   D. Couch, Keowee Hydrostation Manager
   *T. Curtis, Compliance Manager
   *J. Davis, Technical Services Superintendent
   *D. Deatherage, Operations Support Manager
   B. Dolan, Design Engineering Manager, Oconee Site Office
   *W. Foster, Maintenance Superintendent
   T. Glenn, Engineering Supervisor
   *O. Kohler, Compliance Engineer
   C. Little, Instrument and Electrical Manager
   *H. Lowery, Chairman, Oconee Safety Review Group
   *B. Millsap, Maintenance Engineer
   M. Patrick, Performance Engineer
   D. Powell, Station Services Superintendent
   *G. Rothenberger, Integrated Scheduling Superintendent
   *R. Sweigart, Operations Superintendent

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

   NRC Resident Inspectors:

   *W. Poertner
   *B. Desai

   *Attended exit interview.

2. Plant Operations (71707) (93702)

   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 and electrical (I&E), and performance personnel.

      Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts during weekdays and on weekends. Some inspections were made during shift change in order to evaluate shift turnover performance.

Actions observed were conducted as required by the licensee's Administrative Procedures. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Turbine Building
Auxiliary Building
CCW Intake Structure
Independent Spent Fuel Storage Facility
Units 1, 2, and 3 Electrical Equipment Rooms
Units 1, 2, and 3 Cable Spreading Rooms
Units 1, 2, and 3 Penetration Rooms
Units 1, 2, and 3 Spent Fuel Pool Rooms
Unit 3 Containment
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Keowee Hydro Station

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

Within this area, no violations or deviations were identified.

b. Plant Status

Unit 1 operated at power for the entire reporting period.

Unit 2 operated at power for the entire reporting period.

Unit 3 entered the reporting period in a refueling outage. On March 30, 1991, the generator was tied on the grid ending a 44 day outage. On April 1, the unit tripped due to spurious actuation of the Diverse Scram System. The problem was corrected and the Unit restarted and returned to power operation on April 2.

c. Inoperable HPI Flow Instrumentation

On March 19, 1991, with Unit 3 in a refueling outage the licensee determined that the high pressure injection (HPI) crossover flow instrument to the "B" HPI header impulse lines were reversed. The licensee discovered the crossed impulse lines as a result of post modification testing when the flow instrument read zero with flow through the crossover piping. The HPI crossover flow instruments had been replaced with more accurate instruments during the outage; however, the impulse lines had not been modified as part of the modification package. Subsequent investigation by the licensee determined that the impulse lines and flow instruments had been replaced in May 1984, under Nuclear Station Modification (NSM) ON-1782, and that a flow test had not been specified as part of the post modification testing. The licensee rerouted the impulse lines and verified that the impulse lines for the crossover flow instruments installed in Units 1 and 2 were installed correctly. Subsequent to this event the licensee inspected the orientation of the flow element orifice plates installed in the Unit 1 and Unit 2 crossover lines. During these inspections the licensee determined that the orifice plate installed in the Unit 2 crossover flow element associated with the "A" HPI header was installed in the reverse direction. The licensee declared 2HP-410, HPI crossconnect valve to the "A" HPI header, inoperable based on its associated flow instrument being inoperable per the requirements of Technical Specification (TS) 3.3.1.c.

Isolation of the flow element requires that seal injection to the Reactor Coolant Pumps (RCPs) be secured which is undesirable during power operation. The licensee's initial course of action was to make preparations to install freeze seals on the four inch stainless steel piping to the flow element. This would have allowed seal injection to the RCPs to continue and isolate the flow element to allow maintenance personnel to reorientate the orifice plate installed in the flow element. Subsequent evaluation by Design Engineering determined that the flow error induced by the reversed orifice plate would be less than 20 percent based on industry evaluations and testing of other orifice plates installed in the reverse direction and that the flow instrument would be biased in the minus direction. Based on this evaluation, the licensee performed a 10 CFR 50.59 evaluation to revise the Unit 2 Emergency Operating Procedures (EOPs) to limit flow through the HPI crossover flow line to the "A" HPI header to 300 gpm or less. The original flow limit in the EOPs was 475 gpm and was based on preventing pump runout conditions during a small break LOCA. The 300 gpm value was chosen to ensure pump runout conditions during a small break LOCA would not occur and flow in the "A" HPI header would be greater than the minimum required accident analysis value of 225 gpm. The licensee also manufactured an orifice plate to the same specifications as the installed orifice plate and sent the orifice plate to Alden Labs for testing to determine actual flow bias. The testing was completed subsequent to the EOP change and indicated that the flow instrument's maximum bias error would be 13.5 percent. The licensee presently plans to return the orifice plate to its proper orientation during the next Unit 2 shutdown.

Technical Specification 3.3.1.c requires that valves HP-409 and HP-410 be operable whenever power is greater than 60 percent full power. TS define operable as all essential instrumentation required in order to assure performance of the safety function being capable of performing its related support functions.

As a result of the crossover flow instrumentation being inoperable, valve 3HP-409 was inoperable from May 1984 until March 1991 and valve 2HP-410 was inoperable for an extended period of time probably since initial installation. These two examples of inoperable HPI components are identified as apparent violation 50-269,270,287/91-09-01 and are under consideration for escalated enforcement action.

Within this area, one apparent violation was identified.

d. Leaking Incore Closure Housing Vent Plugs

On March 23, 1991, while performing the post refueling outage hot shutdown inspection of the Unit 3 Reactor Building, the licensee identified leakage coming from several of the 52 incore monitoring system (IMS) closure housing units. The leakage was found to be coming from the vent plugs on the IMS closure housing units. Each of the 52 IMS units has two 0.54 inch vent plugs for a total of 104 plugs per unit. All 104 plugs were replaced during the recent refueling outage. The replacement plugs were found to have been of the wrong type, ISO 7/1 versus ANSI NPT. The licensee performed an inspection of the IMS closure head housings in Units 1 and 2 to determine the status of the plugs since they had also been replaced during recent plant outages. The plugs in Unit 1 were found to be of the correct type and the plugs in Unit 2 were found to be mixed but none of the plugs were found to be leaking. All the plugs in Unit 3 were replaced with the correct type plug and the plugs in Unit 2 were successfully hydrostatically tested to 1.1 times the reactor coolant (RCS) pressure using a test fixture. Furthermore, an operability evaluation by Duke's Design Engineering Department determined that in the unlikely event that the plugs were expelled, the flow area size would be small enough that HPI makeup would exceed the flow through the holes. The RCS inventory would not be compromised and the unit could be brought to a safe shutdown. Subsequent to the replacement of the vent plugs, Unit 3 restart was recommenced.

Within this area, no violations or deviations were identified.

e. Unit 3 Trip Due to Diverse Scram System Actuation

On April 1, 1991, Unit 3 tripped from 87 percent power due to a Diverse Scram System (DSS) actuation. The DSS is designed to mitigate the effects of a transient and to detect a failure of the Reactor Protection System (RPS). The DSS is totally independent of the RPS and monitors Reactor Coolant System (RCS) pressure. If both channels of DSS sense an RCS pressure of 2450 psig, the auxiliary Control Rod Drive (CRD) power supply and the regulating CRD power supplies are deenergized and the turbine bypass valve control setpoint is increased by 125 psig. This system was installed during the current Unit 3 outage and had been installed in Unit 2 during the last Unit 2 outage. This system is scheduled to be installed on Unit 1 at the next scheduled Unit 1 refueling outage.

At the time of the event the DSS system was being returned to service after both channels being in bypass due to spurious trip signals being received on channel 1 of the DSS. Instrumentation and Electrical (I&E) technicians had performed troubleshooting procedures on the system and the source of the spurious trip signals on channel 1 could not be determined. Operations was returning the system to operation after troubleshooting when the event occurred. When the operator returned channel 1 of the DSS to service by placing the bypass/enable switch to enable, the channel indicated that a trip signal was present. The operator reset the trip signal locally at the panel by depressing the test/reset button. When the operator placed channel 2 into the enable position, channel 2 also returned to service in the tripped condition. The operator attempted to reset the trip signal locally at the panel by depressing the test/reset button; however, the channel would not reset locally. The operator was going to return channel 2 to the bypass condition for troubleshooting when a spurious trip signal was received on channel 1 of the DSS. This completed the two out of two logic required to actuate the DSS system and the regulating rods (Groups 5,6,7) dropped into the core.

The operator in the control room observed the regulating rods dropping into the core and manually tripped the reactor prior to the RPS system initiating a reactor trip signal on variable low RCS pressure. Troubleshooting by the licensee determined that a loose Input/Output circuit card in the electronics of the channel 1 trip circuitry was responsible for the spurious trip signals in channel 1. The licensee determined that channel 2 did not reset when the operator pressed the local test/reset button due to the design of the DSS. The local test/reset button is intended to be used only during surveillance testing of the DSS. When both channels are enabled, the local pushbutton will not reset the trip signals. The trip signal must be reset by the trip/reset button in the control room located at the CRD Diamond Station. The operations training package associated with this modification implied that the trip/reset button in the control room was used to reset a DSS trip signal once the DSS system actuated and RCS pressure decreased below 2450 psig.

The licensee determined that the channels returned to service in the tripped condition due to voltage spikes when the bypass/enable switch was operated and that, when added to the normal RCS pressure signal, caused the channel to sense that the trip setpoint had been exceeded. The DSS system was returned to service and a plant restart was commenced. Subsequent to the restart of the unit, a time delay was added to the DSS trip logic to prevent a trip signal from occurring when the bypass/enable switch is operated.

Review of this event by the inspectors concluded that a weakness existed in the operations training package associated with this plant modification package, in that operations personnel did not fully understand the operation of the DSS with respect to returning the system to service.

Within the area, one weakness was identified.

f. Containment Integrity

On April 10, 1991, Unit 2 steam generator sample isolation valve 2FDW-108 failed its performance stroke test. The valve stroked in approximately three seconds instead of the procedure required time of one second. Valve 2FDW-108 is an air operated valve used to ensure containment integrity and is located in the penetration room. The valve was declared inoperable and the unit entered an LCO pursuant to TS 3.6.3.c. The redundant containment isolation valve 2FDW-107 was verified closed and the breaker was tagged open as required by the TS action statement.

The licensee is investigating the possible causes that could have resulted in the valve failing its performance test. In addition, Design Engineering is evaluating whether the stroke time requirements on the valve are too stringent and whether the stroke time criterion should be changed. The inspectors will continue to monitor the licensee's actions pertaining to this matter.

On April 10 the licensee also discovered that a performance test instrument used for local leak rate testing (LLRT) of several electrical penetrations during the Unit 3 outage was out-of-tolerance. This invalidated the LLRT test performed using this instrument. As a result, Unit 3 entered a 48 hour LCO pursuant to TS 3.6.6.(2).

Following completion of the LLRT of the electrical penetrations during the Unit 3 outage, the subject leak rate flow monitor was sent to Duke Power Company's Standards and Testing Facility for calibration. During this calibration, it was identified that the subject instrument was out-of-tolerance at mid to high ranges and inoperable at low ranges. The cause of the instrument being out-of-tolerance was attributed to a circuit card not inserted properly and the instrument was taken out of service. The licensee could not determine when the instrument had become inoperable; therefore, retest of the subject electrical penetrations was required.

The unit exited the LCO on April 11 when the penetrations were retested and the leak rates found to be within acceptable limits. The inspectors witnessed portions of the test and did not identify any discrepancies.

Within this area, no violations or deviations were identified.

g. Mispositioned LPSW Valves

On April 12, 1991, the licensee discovered that two Reactor Building (RB) hose rack header isolation valves, 3LPSW-563 and 3LPSW-564 were in the open position. These valves were required to be closed for the current plant conditions. These two valves are located in the RB and function as manual header isolation valves for the fire hydrant hose connections. This connection is also used to supply water while cleaning the Reactor Building Cooling Unit (RBCU) coils. Licensee personnel were in the process of aligning hoses to initiate washing the RBCU coils. During this time, valves 3LPSW-563 and 3LPSW-564 were found to be in the open position. These four inch fire hydrant headers tap off the LPSW line serving the Reactor Coolant Pump (RCP) motor cooling sub-systems. In addition, the valves serve as code class boundary separation valves, in that, piping up to the valves is seismically qualified and piping down stream of the valves is not seismically qualified. With 3LPSW-563 and 3LPSW-564 left in the open position, following certain postulated seismic events, a potential for the non-seismic pipe to rupture exists which could lead to RB flooding. However, a containment isolation valve is located on the LPSW line serving the RCP cooling sub-systems which gets a close signal following Engineered Safeguards (ES) actuation due to high RB pressure.

The valves are normally opened per OP/3/A/1102/10, Controlling Procedure for Unit Shutdown, to accommodate outage requirements. OP/3/A/1102/01, Controlling Procedure for Unit Startup, Enclosure 4.5, preheatup RB startup valve checklist, requires these valves to be shut prior to reaching Reactor Coolant System (RCS) temperatures and pressures of 250 degrees F and 350 psig.

On March 19, 1991, following the refueling outage, the two valves were closed per OP/3/A/1102/01. Plant startup had to be stopped on March 23 due to leaks on the incore assemblies (see paragraph 2.d), and a shutdown was initiated. During this shutdown, per OP/3/A/1102/10, 3LPSW-563 and 3LPSW-564 were reopened on March 24. On March 26 following repairs on the incore instrument assemblies, a new startup procedure was initiated; however, the checklist containing 3LPSW-563 and 3LPSW-564 was not performed and the step requiring the performance of the checklist was signed off per completed files performed on March 19. The Senior Reactor Operator (SRO) signing off the step did not realize that these valves had been reopened. The valves stayed in the open position until April 12, when they were found open by licensee personnel trying to align hoses to wash the RBCUs. Following completion of RBCU washdown, the valves were shut and verified by the unit supervisor. Technical Specification (TS) 6.4.1 requires that the station be operated and maintained in accordance with approved procedures. The operating procedure for unit startup, OP/3/A/1102/01, requires valves 3LPSW-563 and 3LPSW-564 to be shut prior to reaching RCS temperatures and pressures of 250 degrees F and 350 psig. Failure to meet the requirements of OP/3/A/1102/01 with respect to maintaining 3LPSW-563 and 3LPSW-564 in the closed position, is identified as violation 50-287/91-09-02: Failure to maintain plant configuration control.

In addition, it was noted that in procedure OP/3/A/1102/01 the two valves appear in a RB startup valve checklist grouped with LPSW valves serving the RCP sub-systems; whereas, the two valves are specifically listed to be opened in the body of shutdown procedure OP/3/A/1102/10. Therefore, during this evolution where the status of the RCPs remained unchanged, it was easy for the operator to erroneously assume that the checklist containing the valves had been completed.

Within this area, one violation was identified.

h. Potential Loss of Keowee Auxiliary Load Centers

On April 12, 1991, at 1:30 p.m., both Keowee hydro units were declared inoperable due to potential breaker coordination problems on the Keowee auxiliary load centers with respect to breaker overcurrent relays and ground fault protection logic. This item was identified as part of an ongoing licensee review of plant relay settings which was initiated as corrective action to previously identified problems with relay setpoints. The design review identified that non-safety-related loads connected to the Keowee auxiliary Motor Control Centers (MCCs) 1XA and 2XA, could potentially cause the loss of the safety related MCCs due to ground faults that could actuate the ground fault protection logic and isolate power to the safety related MCCs prior to actuation of the circuit breaker supplying the non-safety related load, and that instantaneous overcurrent protection of the non-safety related load supply breakers may not actuate prior to the instantaneous overcurrent protection relays of the MCCs supply breakers which would cause a loss of the safety related MCCs. To resolve this potential problem, the licensee defeated the ground fault protection logic by installing jumpers, removed the instantaneous overcurrent trip relays from the 1X and 2X load center supply breakers to the MCCs and installed short time overcurrent protection devices instead, and removed the MCC's normal supply breaker and hard wired the supply cables from the load center supply breaker to the MCCs. The MCC's normal supply breaker was removed because the breaker was a molded case circuit breaker and the instantaneous overcurrent feature could not be replaced with a short time overcurrent protection device. Although both Keowee units were technically inoperable due to this problem, only one Keowee unit was disabled at any one time to correct the breaker coordination deficiency, and although potentially degraded, the other Keowee unit was available to supply emergency power. This item was reported to the NRC as a 4 hour non-emergency event via the ENS. Further review and long term followup of this item will be accomplished as part of an LER, which is required to be issued by May 12, 1991.

Within this area, no violations or deviations were identified.

i. Maintenance/Surveillance Outage on the Keowee Units

On April 16, 1991, both Keowee Hydro Units were removed from service for planned maintenance and surveillance activities as allowed by TS 3.7.6. TS 3.7.6 allows both Keowee units to be unavailable due to planned maintenance or testing for a period of 72 hours provided the 4160 volt standby buses are energized by a Lee gas turbine through the 100 KV transmission circuit. During the outage, both Keowee units were dewatered for inspection, and modifications were performed on the Keowee underground path circuit breakers and overhead path circuit breakers control logic circuitry to correct the potential single failure concern previously identified by the licensee and discussed in NRC Inspection Report Nos. 50-269,270, 287/91-02.

The outage was originally scheduled to last less then 24 hours; however, problems were encountered during the testing associated with the Keowee circuit breaker modification. As a result of the modification testing problems, the licensee decided to send support personnel home at approximately midnight on April 16, 1991, and to rewater the Keowee units starting on day shift April 17, 1991, even though all items required to be accomplished prior to rewatering had been completed. The inspectors expressed a concern to licensee management regarding not rewatering the Keowee units at the earliest opportunity available. Although the Keowee units would still have been inoperable if they had been rewatered prior to the post modification testing of the Keowee output breakers control circuitry, they would at least have been available and could have potentially supplied emergency power in the event of an accident.

Within this area, one concern was identified.

j. HPI System Inoperability Due to High Letdown Storage Tank Gas Pressure

On April 16, 1991, at approximately 4:10 p.m., the licensee determined that pressure in the Unit 2 letdown storage tank (LDST) had exceeded the maximum allowable value contained in High Pressure Injection System operating procedure OP/2/A/1104/02. The operating procedure contains a graph of LDST level versus LDST pressure and the operators are required to maintain LDST pressure below the curve for a given LDST level. The purpose of the graph is to ensure that the HPI pumps do not become gas bound due to hydrogen intrusion from the LDST during operation of the HPI system in its emergency operating alignment. This curve is necessary because the LDST does not isolate on an emergency actuation of the HPI system.

The hydrogen addition line to the LDST is normally isolated from the LDST by a closed solenoid operated valve 2H-1, manipulated from the control room and a closed manually operated valve 2H-26, upstream of the solenoid valve. During the addition of hydrogen to the LDST a non-licensed operator aligns the hydrogen system then opens the manual valve upstream of 2H-1 at which time the operator in the control room opens 2H-1 to add hydrogen to the LDST. When the hydrogen addition is complete the operator in the control room shuts valve 2H-1 and notifies the non-licensed operator to shut the manual isolation valve and secure the hydrogen system.

At approximately 4:00 p.m., on April 16, hydrogen addition to the Unit 2 LDST was commenced. At 4:06 p.m. valve 2H-1 was closed from the control room and indicated on the control board that it was closed and the non-licensed operator was notified to shut the manual isolation valve. When 2H-1 was shut from the control room, LDST pressure was within required limits. When the non-licensed operator commenced shutting the manual isolation valve, flow was still indicated in the line by flow noise until the manual valve was fully shut. The non-licensed operator checked the local LDST pressure gage and determined that pressure appeared to be higher than normal. The non-licensed operator returned to the control room and discussed the higher than normal pressure indication with the control room operators at 4:10 p.m., at which time it was determined that LDST pressure exceeded the maximum allowable pressure of 50 psig by 5 psig. The operators vented the LDST to the gaseous waste tanks and LDST pressure was reduced to less than 50 psig at 4:28 p.m. This item was reported to the NRC as a four hour non-emergency event and a work request was initiated to determine why valve 2H-1 did not operate properly. Long term corrective actions for this event will be followed by review of the LER.

Within this area, 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/3/A/0150/05	LLRT of Electrical Penetrations
IP/0/A/0310/012A	ES Online Test
IP/0/A/310/8A	2FDW108 Stroke Time Test
MP/0/A/1720/10	Hydrostatic Test on Portions of Unit 1 RBS System
PT/2/A/115/04	EFW System Valve Verification
PT/2/A/610/17	Operability Test of 4160V Breakers
IP/0/A/4980/52B/RE	Westinghouse Amptector Circuit Breaker Trip Device Test

Within this area, no violations or deviations were identified.

4. Maintenance Activities (62703)

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify; proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

Maintenance reviewed and witnessed in whole or in part:

WR 99822C	Install Exempt Change 3854
WR 32489C	Investigate and Repair Cause of Spurious Trip of DSS Channel 1

Within this area, no violations or deviations were identified.

5. Station Modifications (Unit 3, Keowee Hydro Units) (37828)

The inspectors reviewed portions of several Nuclear Station Modification (NSM) packages. Emphasis was placed on ensuring work was completed in accordance with the NSM. Two modification packages concerning the Motor Driven Emergency Feedwater (MDEFDW) System, NSM 32767: Reroute Suction piping from hotwell to MDEFDW pumps, and NSM 32858: Installation of a full flow test loop were reviewed as well as system walkdowns performed. NSM 32767 involved rerouting the suction piping for the MDEFDW pumps from a high point well above the bottom of the hotwell to the bottom of the hotwell. This will allow utilization of the full contents of the hotwell for steam generator cooling following loss of main feedwater. The modification also removed previous suction piping that is no longer required. NSM 32858 involved installation of a connecting line from a point on the six inch line after each MDEFDW pump's automatic recirculation control valve. This connecting line will enhance testing of the pumps in that the pumps can now be tested at full flow at any time without special valve operations.

The licensee also performed an exempt change to permanently correct problems involving potential single failure resulting in potential loss of both Keowee Hydro Units discussed in NRC Inspection Report Nos. 50-269,270,287/91-02. The modification installed electrical contacts operated from the disconnect switches and breakers, in the circuits controlling the closing of breakers ACB-3 and ACB-4. Each of these circuit breakers will close only when: the other circuit breaker is open; or, the other circuit breaker disconnect switches are open; or, the circuit breaker's own disconnect switches are open. The inspectors witnessed portions of the installation and reviewed the post modification testing. This modification will preclude the possibility of the potential single failure from occurring.

Within this area, no violations or deviations were identified.

6. Inspection of Open Items (92700)(92701)(92702)

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

a. (Closed) Inspector Followup Item 50-269,270,287/89-19-01: Improve procedure requirements for positive exposure controls in very high radiation areas and placement and monitoring of SRPDs. The following actions to address the above concern were accomplished by the licensee and reviewed by the inspectors.

- Station Directive 3.3.1, paragraph 4.1.2 and 4.1.3 and Station Directive 3.3.5, paragraph 4.9.6 were changed to require monitoring of SRPDs periodically while in the RCA and RCZ.

- Radiation Protection Section Manual, Section 4.2, paragraph 3.2.1.5 and Procedure HP/0/B/1000/04 were changed to implement more positive exposure controls in high and very high radiation areas.

b. (Closed) Inspector Followup Item 50-269,270,287/89-06-01: Resolve/repair interference between temperature element and structural steel. In the Unit 2 Turbine Building a steamline thermocouple 2MS TE0439 came within 1/8 inch of being in contact with the bottom of a wide flange. The inspector inspected the repair in the field and reviewed WR 19790C.

6. Exit Interview (30703)

The inspection scope and findings were summarized on April 24, 1991, 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
270,287/91-09-01	Apparent Violation - Inoperable HPI components, paragraph 2.c. This item is under consideration for escalated enforcement.
287/91-09-02	Violation - Failure to maintain plant configuration control, paragraph 2.g.

A weakness was identified in the operations training package associated with the DSS system, paragraph 2.e.

A concern was expressed concerning securing Keowee personnel for the night prior to rewatering the Keowee units, paragraph 2.i.