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

Report Nos.: 50-269/94-16, 50-270/94-16 and 50-287/94-16

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: May 1 - June 4, 1994

Inspectors: [signature] 6/16/94
P. E. Harmon, Senior Resident Inspector — Date Signed

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Approved by: [signature] 6/16/94
M. V. Sinkule, Chief, — Date Signed
Reactor Projects Branch 3

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance activities, and engineering and technical assistance.

Results: An apparent violation (with two examples) was identified involving the failure to follow refueling procedures (paragraph 2.c).

Additionally, a violation occurred when a control room operator inadvertently diluted the Unit 3 Reactor Coolant System (paragraph 2.d).

The licensee discovered a potential single failure vulnerability in the Engineered Safeguards (ES) System involving a loss of manual control of certain ES equipment from the control room following a failure of a common grounding wire. The Licensee completed an operability evaluation for this configuration which is being reviewed by the NRC. This issue was identified as an Unresolved Item (paragraph 4.b).

The inspectors noted that the reactor coolant pump seal injection flow path and the normal makeup flow path were isolated during the

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performance of a High Pressure Injection pump run-out test. These flow paths would normally be open during an accident and could result in different pump run-out flows than that produced during the test. This item was identified as an Inspector Followup Item (paragraph 3.b.(3)).

Inconsistencies between the Final Safety Analysis Report, the Emergency Operating Procedures, the Design Basis Document, and various calculations were noted regarding the minimum Reactor Building sump level required for adequate Reactor Building Spray pump net positive suction head (paragraph 4).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*B. Peele, Station Manager
*S. Benesole, Regulatory Compliance Manager
D. Coyle, Systems Engineering Manager
J. Davis, Engineering Manager
T. Coutu, Operations Support Manager
*B. Dolan, Safety Assurance Manager
W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
D. Hubbard, Component Engineering Manager
C. Little, Superintendent, Instrument and Electrical (I&E)
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.

*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 was in a scheduled refueling outage throughout the inspection period.

Units 2 & 3 operated at or near 100 percent power throughout the inspection period.

c. Unit 1 Refueling Activities

The licensee commenced Unit 1 refueling activities on May 25, 1994. Refueling activities were controlled by procedure OP/1/A/1502/07, Refueling Procedure. Step 1A of Enclosure 5.2, Refueling Verification Form, required Fuel Assembly 585 located in Spent Fuel Pool location C62 to be inserted in core location N14. Fuel Assembly 585 was the first fuel assembly to be inserted into the reactor vessel for core reload. During a routine review of refueling activities the inspectors determined that Fuel Assembly 585 was located in core location O13 with the fuel assembly still grappled to the fuel handling mast. Discussions with the refueling Senior Reactor Operator (SRO) determined that Fuel Assembly 585 was located in core location O13 per an intrastation letter from Nuclear Engineering. The letter identified intermediate core locations for Fuel Assemblies 585,587,58F,5RV,5RL,57G, and 5T9. The purpose of the alternate fuel moves was to obtain data on source counts at the different locations to determine if regenerative source rods were needed to bring the new Gamma-Metric Nuclear instruments on scale. The inspectors questioned the acceptability of positioning fuel assemblies in intermediate locations without approved procedural guidance. Based on the inspectors' concerns the licensee suspended fuel handling activities until alternate fuel handling steps were generated in Enclosure 5.2A of OP/1/A/1502/07 to reflect the fuel handling activities requested by the intrastation letter. (Note: only fuel assemblies 585 and 587 underwent positioning in intermediate locations.)

OP/1/A/1502/07, Refueling Procedure, Step 4.2, Procedure, Note 2 states: If it becomes necessary to alter the planned refueling sequence, a note should be placed in Enclosure 5.2 (Refueling Verification Form) where the departure occurs. The alternate moves shall then be documented in enclosure 5.2A (Alternate Core Loading Verification Form). The failure to meet the requirements of OP/1/A/1502/07 with respect to documenting the alternate fuel movement activities associated with Fuel Assembly 585 is identified as Apparent Violation 269/94-16-01: Failure to Follow Refueling Procedures.

On May 26, 1994, at approximately 4:10 p.m., the licensee determined that the fuel assembly located in core location M4 was not the correct fuel assembly required by the refueling procedure. The licensee identified the problem during the performance of step

70 of enclosure 5.2, Refueling Verification Form. Step 70 required Fuel Assembly 75L located in Spent Fuel Pool location K1 to be placed in core location N9. When the Spent Fuel Pool bridge operators went to location K1 to retrieve Fuel Assembly 75L, the location was empty. Subsequent investigation by the licensee determined that Spent Fuel Pool location L1 contained a fuel assembly. This location should have been empty per the refueling procedure. Step 38 of enclosure 5.2, Refueling Verification Form, required Fuel Assembly 75V located in Spent Fuel Pool location L1 to be placed in core location M4. The licensee then verified that core location M4 contained Fuel Assembly 75L. Fuel Assembly 75L was placed into core location N9 as required by the refueling procedure and Fuel Assembly 75V was then placed in core location M4. The failure to meet the requirements of procedure OP/1/A/1502/07, Enclosure 5.2, step 38 is identified as another example of Apparent Violation 269/94-16-01: Failure to Follow Refueling Procedures.

The licensee was cited three times in the past four years for failure to maintain configuration control of fuel assemblies in the Spent Fuel Pool and the Reactor Vessel during core offload and reload activities. The last citation occurred on December 31, 1992, when Fuel Assembly 4MU was placed in core location M13 instead of Fuel Assembly 5R4 as required by the refueling procedure. The most recent examples demonstrate a continued weakness in the licensee's program for fuel handling, as well as a continued lack of attention to detail on the part of the fuel handling staff.

d. Inadvertent Dilution Of Unit 3 Reactor Coolant System

At approximately 11:00 p.m., on May 23, 1994, the Chemistry Department requested the Unit 3 Balance Of Plant (BOP) reactor operator to de-lithiate the reactor coolant system (RCS) for 10 minutes. De-lithiation of the RCS via demineralizers in the letdown portion of the High Pressure Injection (HPI) system is a routine process for RCS pH control. The BOP operator discussed using the 3B Deborating Demineralizer for this process, as the Control Room Turnover Sheet designated using this boron saturated demineralizer for de-lithiation. The appropriate procedure for this process was OP/3/A/1103/04, Soluble Poison Concentration Control, Enclosure 3.17, Operation of 3B Deborating Demineralizer to De-lithiate Unit 3. The BOP operator inadvertently utilized Enclosure 3.16, Operation of 3A Deborating Demineralizer to De-Lithiate Unit 3", which routed letdown flow through the non-boron saturated 3A Deborating Demineralizer, for 10 minutes. At 11:30 p.m., the control room operators noted the control rods were inserting and discovered the use of the wrong Enclosure. Feed and bleed via the 3A Bleed Holdup Tank (BHUT) was initiated immediately to restore previous RCS boron concentration. As a result of the dilution, the Integrated Control System (ICS) automatically inserted the control rods from 93.5% to 87.5% on

Group 7 (23.2 % on group 7 was the rod insertion limit). The total deboration of the RCS was 6 ppm, from 1071 to 1065 ppm.

Utilization of Enclosure 3.16 (Demineralizer 3A) and 3.17 (Demineralizer 3B) is procedurally controlled by initial condition verification. Initial Condition Step 1.1 of Enclosure 3.16 to OP/3/A/1103/04 requires verification that: "Operations notified by Chemist that de-lithiation is required with the use of 3A Deborating Demineralizer." The BOP operator mistakenly initialed/verified this step and utilized Enclosure 3.16. The chemist had in fact requested the 3B Deborating Demineralizer, which was consistent with the Control Room Turnover Sheet. This matter is identified as Violation 287/94-16-02: Failure to Follow Procedure Results in Inadvertent Dilution of the RCS.

e. Mid-loop/Reduced Inventory Activities

During the Unit 1 End Of Cycle 15 Refueling Outage, the licensee reduced RCS inventory and reached the mid-loop operations level on May 3, 1994, at 9:24 p.m. This was done for the purpose of removing the steam generator manway covers and installation of steam generator nozzle dams. The inspectors reviewed the licensee's program prior to the reduction of RCS inventory and verified that the requirements were met while operating at the reduced inventory levels as specified in Operations Procedure OP/3/A/1103/11, Draining And Nitrogen Purging Of RC System, Enclosure 3.6, Requirements For Reducing RXV Level To < 50" on LT-5. This procedure stipulated the sequence and steps required for reduction of RCS inventory and mid-loop operation. It further specified the precautions and limitations to be adhered to while in mid-loop.

Step 1 of Enclosure 3.6 specifically addressed the ability to establish containment closure. The licensee implemented a Shutdown Protection Plan for the outage which required the containment to be closed except as necessary to bring materials and tools in and out of the Reactor Building. It further required that penetrations be closed except for those with temporary cables installed for necessary outage activities (e.g., steam generator tube testing, maintenance, etc.). In both instances when containment integrity was not maintained, a plan for quick closure was addressed.

The requirement for two independent trains of RCS level monitoring was met when operating at reduced inventory. It was accomplished by the use of one permanently installed instrument (LT-5) and two temporarily installed ultrasonic instruments for the outage. Level indications were displayed in the control room on the LT-5 indicator, the Inadequate Core Cooling Monitor, and on the Operations Aid Computer.

The inspector verified that two trains of core exit thermocouples were available/utilized while at reduced inventory and that two sources of inventory makeup and cooling were either in use or available for operation. In addition, the inspector verified that contingency plans existed to re-power vital busses from available alternate electrical power supplies in the event of a loss of the primary source.

During the time that Unit 1 was in a reduced inventory status, the licensee implemented and maintained the requirements specified for the condition. The unit exited the mid-loop operating regime on May 4, 1994, at 6:05 p.m. The unit was in mid-loop operations for 20 hours and 41 minutes. The program was well implemented and the operation at reduced inventory was accomplished without incident.

f. Missing Unit 1 Steam Generator Plug

On May 5, 1994, the licensee identified that the rolled tube plug installed in Steam Generator 1B lower tubesheet row 130, tube 89, was missing. The missing plug was identified during a video scan of the lower tubesheet. The missing plug was an inconel 600 plug that was installed during the Unit 1 End of Cycle (EOC) 11 refueling outage in January 1989. The plug was inspected with a Motorized Rotating Pancake Coil (MRPC) eddy current probe during the last Unit 1 refueling outage (EOC 14) in December 1992, and no degradation was observed. The licensee verified by review of a video tape made of the installation of a nearby rolled plug (row 131, tube 88) that the plug was in place as of December 1992. The licensee verified that no other plugs were missing and initiated plans to search for the missing plug and retrieve it. The plan included inspecting the 1B steam generator lower bowl drain line, the Reactor Vessel and the fuel assemblies during core off-load.

On May 10, 1994, during core off-load activities the licensee identified two pieces of metal on the bottom of Fuel Assembly 57M located in core location K7. The fuel assembly was transferred to the Spent Fuel Pool and the pieces of metal were removed from the fuel assembly and stored in the Spent Fuel Pool. Video inspection of the pieces showed that they were definitely part of a tube plug and that the total length approximated an intact plug. The pieces were removed from the pool and shipped to Babcock & Wilcox (B&W) for review and failure analysis.

Licensee activities associated with steam generator inspections were reviewed by Region based specialists during the weeks of May 16 and May 23, and licensee activities were found to be acceptable. These activities are documented in NRC Inspection Report 269,270,287/94-17. As of the end of this inspection period, the licensee had not identified the failure mechanism that resulted in the plug failure.

Within the areas reviewed one violation and one apparent violation were identified. The violation involved an inadvertent dilution of the Unit 3 RCS. The apparent violation involved two examples of failure to follow refueling procedures.

3. Maintenance and Surveillance Testing (62703 & 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 (WO) 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:

(1) Work Order Task, 94000681-01, Perform OE-5803, Modify ICS BTU Limit Circuit (Minor Modification).

On May 4, 1994, the inspector reviewed activities in progress on Unit 1 during the implementation of the minor modification to simplify the BTU Limits Circuitry that feeds the Integrated Control System (ICS). The modification was to simplify the ICS BTU circuitry by removing the Reactor Coolant flow and Feedwater temperature inputs to the BTU limit calculation. The new calculation for BTU limits would be based on the T-hot and Once Through Steam Generator (OTSG) outlet pressure inputs only.

The primary purpose of the BTU Limits Circuitry is to alert the operator of potential BTU limit conditions and assure rapid runback of feedwater flow following a reactor trip. The technical basis for the modification was documented in B & W Document, 12-1175342-00 which determined that only the T-hot and the OTSG outlet pressure inputs were needed.

The inspector reviewed the licensee's safety evaluation which determined the modification met acceptable criteria for implementation. In addition, the work efforts were reviewed and it was concluded that the activity was performed per the work instructions and properly documented.

(2) Work Order 94018639-01, Investigate and Repair 3FDW-107.

During the performance of a quarterly stroke test (PT/3/A/0150/22A), 3FDW-107 did not give a full open indication. This valve is the Unit 3 "B" steam generator sample isolation valve, located inside containment. This normally closed valve is a motor operated containment isolation valve that receives an Engineered Safeguards close signal. A containment entry was made to investigate the apparent failure to fully open. The investigation revealed a problem with mechanical binding within the valve. Given the recent problems at Oconee with Limitorque valve torque switches (see IFI 94-11-02), the inspector observed the troubleshooting efforts to verify that the problem was not related to the torque switch. The valve was subsequently closed and its feeder breaker left tagged in the open position. The licensee indicated that the valve would be repaired at the next available outage.

(3) Work Order 94012651-01, Repair ES Analog Channel B Jack.

The inspector reviewed the work order and monitored work in progress during the implementation of this work activity. The activity was performed per the work instructions and properly documented on the work order.

(4) Work Order 94040400-01, Implement Minor Mod OE-6668.

The inspector reviewed the work package and monitored work in progress during the implementation of this work activity. Minor Modification OE-6668 was implemented to connect the neutral side of the Engineered Safeguards (ES) unit control module latch permissive relays (K1 and K2) to AC neutral instead of instrument ground as previously configured. This modification was implemented to correct a problem identified during component ES testing (see paragraph 4.b). The work activities observed were performed in accordance with approved procedures and properly documented in the work package.

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

Surveillance activities observed or reviewed in whole or in part:

(1) Work Order Task 93081903-01, Perform Test On CT-1 Relays.

On May 12, 1994, the inspector reviewed performance testing of the CT-1 relays that are utilized in the electrical power transfer to the startup busses upon loss of the normal feeder busses. The testing was part of the Unit 1 refueling outage scheduled activities to be performed while the reactor was defueled. Some minor discrepancies were noted in the step signoff sequence in that more than one step in the instructions had been performed prior to the craftsmen signing for the work completion. After the inspector identified the discrepancy, immediate corrections were made.

(2) Turbine Driven Emergency Feedwater (TDEFW) Pump Cooling Water Supply Valve Test (PT/3/A/0150/22L).

This quarterly test verifies cooling water supply to TDEFW pump cooling jackets and oil coolers. The inspector observed portions of the test conducted on the Unit 3 TDEFW pump on May 12, 1994. The test revealed that the stroke times for 3LPSW-138 (cooling water supply to pump jacket), and 3HPSW-184 (cooling water supply to pump oil cooler) were not within the acceptance criteria (1-2 seconds for both valves). The stroke time observed during this test was 4 seconds for both valves. 3LPSW-138 and 3HPSW-184 are pneumatically operated valves that are designed to fail open following a loss of power or loss of instrument air. These valves are normally closed and are designed to open automatically following a pump start. As a result of the slow stroke times, the licensee declared these valves inoperable per their Inservice Test (IST) program. The switch that manually controls both valves was subsequently placed in the bypass position. This failed open both valves; thereby, establishing continuous cooling water flow through the pump jacket and oil cooler. The licensee stated that this arrangement resulted in the TDEFW pump being operable, despite the valves being inoperable, since the valves were in their "fail safe" position.

The inspector noted that the licensee did not perform a 10 CFR 50.59 or other formal engineering evaluation for this abnormal lineup. However, OP/0/A/1102/06, Removal and Restoration of Station Equipment, was used to remove the control switch from its normal position. This required/resulted in an evaluation of the impact on plant equipment by two licensed individuals, one of which held a senior reactor operator license. The inspector questioned whether continuous flow of relatively cool water through the idle pump and oil cooler might result in increased moisture in the oil. Oil samples taken on May 16, revealed that moisture levels had not increased. The licensee subsequently performed numerous stroke tests of these valves to determine if the stroke times were degrading. The valves consistently stroked at 2.5 seconds. On May 26, after changing the stroke time acceptance criteria to 1-4 seconds, the licensee declared the valves operable and restored them to their normal (closed) status. The inspector concluded that there was no impact on TDEFW pump operability, nor a design basis issue associated with extending the stroke time acceptance criteria.

(3) High Pressure Injection (HPI) Pump Run-Out Test (TT/1/A/251/41).

This temporary test procedure was conducted to verify that the flow resistance in the HPI system piping was sufficient to prevent the HPI pumps from reaching a pump run-out condition when the injection valves were completely open and RCS pressure was at 0 psig. The normal pump run-out flow value is 525 gpm, but the licensee has received concurrence from the pump vendor that flow rates up to 585 gpm are acceptable if Net Positive Suction Head (NPSH) available is greater than 30 feet of head. The licensee takes credit for throttling HPI flow within ten minutes following an accident to ensure HPI flows are balanced.

The test consisted of running each HPI pump individually and measuring injection flow and minimum recirculation flow with the respective HPI valve fully open. Pump vibration data was monitored throughout the test and if vibration levels exceeded 0.75 in/sec the pump was to be immediately secured. The A, B, and C HPI pumps developed approximately 545 gpm, 562.5 gpm and 562 gpm respectively with the injection valves fully open. Vibration levels remained below 0.75 in/sec.

The inspector noted that the reactor coolant pump seal injection flow path and the normal makeup flowpath were isolated during the performance of the test. These flowpaths would normally be open during an accident and would decrease system resistance in the A injection header and would affect the pump run-out flows for the A and B HPI pumps. This item was discussed with the accountable engineer and he stated that the test was for data acquisition and that the possible affect on delivered flow would be reviewed by Design Engineering. The inspectors plan to review this item further after the licensee evaluation is completed. This is identified as Inspector Followup Item 269/94-16-04: HPI Pump Run-out Flow Testing.

The inspectors reviewed the test procedure and witnessed the entire testing sequence for all three HPI pumps. The licensee plans to perform this special test on both Units 2 and 3 during the next scheduled refueling outages.

(4) SSF Service Water Test with ASWP, HVAC Pump, and DESWP Running Simultaneously (TT/0/A/600/12).

The purpose of this temporary test procedure was to demonstrate and document the ability of the Safe Shutdown Facility (SSF) service water piping to provide adequate suction pressure and flow while the SSF auxiliary service water pump (ASWP), SSF HVAC pump, and diesel engine service water pump were running simultaneously. The test was conducted with the Unit 2 Condenser Circulating Water (CCW) system in service and supplying suction to the SSF service water systems. Under SSF conditions the Unit 2 CCW system would not be operating. Discussions with the system engineer determined that plans were being established to reperform this test during the next Unit 2 refueling outage when the CCW system could be secured so that actual system conditions could be verified.

The procedure established a minimum suction pressure of 5 psig for the ASWP and the DESWP, and 2 psig for the HVAC pump. The minimum suction pressure observed during the test was 21.8 psig. The inspectors reviewed the test procedure and witnessed the performance of the entire test.

(5) Turbine Stop Valve Movement (PT/0/A/290/04).

This is a monthly test to verify the proper operation of the Main Steam Stop Valves (MSSVs) and Intercept Valves. The inspector observed the test for Unit 3 conducted on May 19, 1994. No discrepancies were noted.

No violations or deviations were identified. One IFI was identified regarding the system lineup during a HPI pump run-out test.

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. Design Basis Documentation Issues Associated With Reactor Building Spray.

On May 17, 1994, the inspector observed the Reactor Building Spray (RBS) pump test (PT/3/A/0204/07) for Unit 3. As part of this activity the inspector reviewed various design basis documents to evaluate how well this test verified that the RBS system performed its design basis functions. The inspector noted that Section 6.1.3 of the Oconee Final Safety Analysis Report (FSAR) stated, in part, that the NPSH available to the Low Pressure Injection and RBS pumps during the post-LOCA recirculation phase has been calculated based on three feet of level remaining in the BWST at time of switchover, and water level in the Reactor Building of 6.5 feet above basement level. It further indicated that based on the 6.5 foot water level, there would be 19.8 feet of NPSH available to the RBS pumps (only slightly greater than the pump manufacturers required NPSH of 17.0 feet).

The inspector noted that this conflicted with step 14.0 of section CP-601 of the Emergency Operating Procedure (EOP) which instructed the operators to swap RBS suction to the Reactor Building Emergency Sump when BWST level was less than 6 feet, and RB level was greater than 3.5 feet. The licensee's Design Basis Specification for the Reactor Building Spray System (OSS-0254.00-00-1034) also stated that the minimum reactor building level setpoint was 3.5 feet.

When questioned about the apparent discrepancy between the FSAR and the EOP, the licensee stated that the information in Section 6.1 of the FSAR was inaccurate, and that it would be corrected during the next update to the FSAR.

In responding to the inspector's questions regarding the basis for the EOP's guidance for swapover (BWST level < 6 ft, and RB level > 3.5 ft), the licensee provided OSC-2820, Emergency Procedure Guideline Setpoints, which indicated that a reactor building level of at least 3.75 feet was necessary to ensure adequate RBS pump NPSH. This was different from both the EOP & DBD (3.5 ft) and the FSAR (6.5 ft). In fact, revision 3 to OSC-2820, dated July 17, 1989, specifically changed the setpoint for swapover from 3.5 to 3.75 feet. Both the licensee and the inspector were unclear as to what the actual requirement was for minimum sump level to ensure adequate NPSH for the RBS pumps, or if the EOP guidance was adequate. Shortly thereafter, the licensee concluded that the current EOP guidance was acceptable due to the fact that an injection of BWST water into the RB which reduces BWST level below 6 feet, assuming an initial level of at least 46 feet (TS requirement), would ensure at least 5 feet of RB water level. Based on independent calculations, the inspector agreed with this assessment for immediate EOP acceptability. However, the inspector was concerned that a revision to the licensee's procedure for EOP setpoints which specifically changed a setpoint was not incorporated into the EOP, and that this was not realized by the licensee until questioned by the NRC approximately 5 years later.

Given the many conflicting references, the inspector concluded that there were shortcomings in the licensee's program for maintaining their design basis documentation for the RBS system. The licensee should determine the actual minimum RB water level necessary to ensure adequate NPSH for the RBS pumps, and adjust their documentation accordingly.

b. Engineered Safeguards (ES) Wiring Discrepancies

On May 20, 1994, during the performance of ES functional testing on valves 1PR-8 and 1PR-10 the licensee found that with an ES signal present, manual control of the valves could not be achieved using the manual pushbutton on the RZ module located on the vertical board in the control room. The ES testing of 1PR-8 and 1PR-10 was being conducted as part of a post modification test requirement for minor modification OE-6338. The licensee reviewed all wiring changes performed per the minor modification and determined that the inability to take manual control from the RZ module under ES conditions was not related to the implementation of the minor modification. A troubleshooting work order was initiated to identify and correct the problem.

Subsequent investigation by the licensee determined that the manual control relays inside the ES cabinets' unit control modules were connected to the instrument ground system and that the electrical circuit for manual control after an ES actuation relied on the instrument ground system, through the station ground system, through the regulated power panelboard 1KRA neutral conductor, to the 120 volt vital power inverters' neutral conductor. The Unit 1 vital inverters and manual bypass switches had been replaced earlier in the current outage per modification NSM-ON-12881. This modification had replaced the single pole bypass switch with a double pole bypass switch. The double pole design switches both the hot wire and the neutral wire between the vital inverter and the regulated power supply, whereas the old single pole switch only switched the hot wires and a common neutral was maintained between the vital inverters and the regulated power supply. With the vital inverters in service following the vital inverter modification, the electrical circuit for manual control following an ES signal was defeated. The licensee plans to modify the Unit 1 Engineered Safeguards electrical circuitry to correct this deficiency prior to completion of the Unit 1 refueling outage. The licensee planned to connect the manual control relays to the vital 120 VAC neutral wire to ensure that an electrical circuit could be achieved.

The licensee performed an operability evaluation on the present Unit 2 and 3 Engineered Safeguards systems. The Unit 2 and 3 systems still contained single pole bypass switches and relied on a common neutral wire, instrument ground system, and station ground system to establish an electrical circuit. The instrument ground system, station ground system, and regulated power supply system were not considered safety-related and the electrical circuit relied on a common electrical cable in several locations to maintain an electrical circuit for manual control of ES components following an ES actuation.

The licensee determined that the Unit 2 and Unit 3 ES systems were operable based on the fact that the grounding system was a passive system and no credible single failure could be postulated for any design basis events. The licensee's operability evaluation was still under NRC review at the end of the inspection period and is identified as Unresolved Item 269,270,287/94-16-03: Engineered Safeguards Wiring Discrepancies.

No violations or deviations were identified. One Unresolved Item regarding Engineered Safeguards neutral and ground wiring arrangements was identified.

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:

a. Combustible Material In The Reactor Buildings

The inspectors toured the Unit 1 reactor building on May 5, 1994, during the refueling outage. At this time, less than 100 bundles of fuel had been removed from the reactor core. The inspectors noted that large amounts of non-flame retardant plastic had been used to cover equipment and other plant items for protection during containment decontamination and had remained after decontamination was completed. In addition, it was noted that rolls of the plastic material were stored in the building and there was no apparent control over the location or amount allowed.

A violation (VIO 287/93-31-03) was issued by the NRC for use of non-fire retardant plastic in the Unit 2 penetration room in December 15, 1993. The use of this material in the unit 3 Reactor Building was questioned during the previous Unit 3 refueling outage and the inspectors learned that fire loading in the Reactor Building was not addressed in the site directives. As a result, Oconee Nuclear Site Directive 3.2.7, Control Of Combustible Materials, was revised. Step 12.7 of the revised directive addressed specific areas of the Reactor Building necessary for cables and equipment important for decay heat removal and required that the Reactor Building Coordinator or designee monitor and control the use of combustibles in those areas through periodic inspections.

Although the directive did not limit the use of combustible materials in the Reactor Building, or require an evaluation for the use of this material, the licensee agreed that the amount appeared excessive and the fire loading was reduced to a much lower level.

b. Maintenance Chemicals With Wintergreen Odor

The inspector detected the smell of wintergreen during a tour of the turbine building on May 12, 1994. Wintergreen odor is utilized in the Carbon Dioxide and Halon fire protection systems at Oconee to alert personnel in those areas of an actuation of the system. After the inspector exited the area and notified the control room of the odor, he learned that plant maintenance utilized a chemical with this odor to assist in loosening bolts.

The inspector questioned the use of this chemical for maintenance activities given that the licensee plant systems training course emphasized the specific use of wintergreen in the carbon dioxide and halon fire protection systems as a warning device for system activation. The licensee agreed that the use of chemicals with wintergreen odor for other than fire protection would defeat the original purpose for detecting a carbon dioxide or halon release. The licensee subsequently discontinued the use of wintergreen odor in the plant with the exception of the fire protection system.

No violations or deviations were identified.

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, 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 LER is closed:

a. (Closed) LER 270/93-04, Emergency Feedwater Required Technical Specification Surveillance Interval Exceeded Due To Management Deficiency.

The licensee identified that the required surveillance for the initiating circuitry for the Unit 2 Motor Driven Emergency Feedwater (MDEFW) pumps had not been performed in the time interval required by the Technical Specification. The problem was identified on August 23, 1993, with the unit at 100 percent power. The time allowed by the surveillance had been exceeded by 28 days. As a result, the surveillance was immediately performed with satisfactory results.

The licensee determined that the deficiency had occurred as a result of placing the surveillance in the "suspend" mode at the time the test was due. It was further determined that the personnel involved believed that once the test was in the suspend mode, the computer program would reschedule the test prior to exceeding the Technical Specification time limit. However, the program did not have this feature, and therefore, the surveillance was not rescheduled. This resulted in the failure to perform the work within the required time period with a 28 day over-run.

The licensee's corrective action was to revise Maintenance Directive 7.3.6, Preventative Maintenance Program, step 5.5.4, Suspending Or Deferring a Predefined Work Order, to require an engineering evaluation for suspending work orders that cannot be performed within the allowable time frame.

The inspectors reviewed the licensee's documentation that the surveillance was performed, reviewed the revised Maintenance Directive, and verified that the commitment was properly implemented.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on June 2, 1994, 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. 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
50-269/94-16-01	Apparent Violation: Failure to Follow Refueling Procedures - two examples (paragraph 2.c).
50-287/94-16-02	Violation: Failure to Follow Procedure Results in Inadvertent Dilution of the RCS (paragraph 2.d).
50-269,270,287/94-16-03	Unresolved Item: Engineered Safeguards Wiring Discrepancies (paragraph 4.b).
50-269/94-16-04	Inspector Followup Item: HPI pump run-out flow testing (paragraph 3.b.(3)).