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

Report Nos.: 50-269/94-32, 50-270/94-32 and 50-287/94-32

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: September 25 - October 29, 1994

Inspectors: [signature] for 11/23/94
P. E. Harmon, Senior Resident Inspector — Date Signed

W. K. Poertner, Resident Inspector
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Approved by: M V Sinkule 11/23/94
M. V. Sinkule, Chief, — Date Signed
Reactor Projects Branch 3

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, maintenance and surveillance testing, onsite engineering, and plant support. As part of this effort, backshift inspections were conducted.

Results: During the inspection period one violation and one non-cited violation were identified. The violation involved two examples of failure to follow maintenance procedures (paragraph 3.a). The non-cited violation involved an inoperable containment isolation valve due to post maintenance testng not being performed because of a maintenance error (paragraph 2.f).

An Inspector Followup Item was identified concerning an inadvertent venting of the Unit 2 quench tank (paragraph 2.e).

A strength was identified in the area of conduct of testing (paragraph 3.b).

A weakness was identified in the procedure for operation of the safe shutdown facility diesel generator (paragraph 3.b).
A weakness was identified in the health physics program concerning the control of radiation control zones (paragraph 5).

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ENCLOSURE 2

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
B. Dolan, Safety Assurance Manager
*W. Foster, Superintendent, Mechanical Maintenance
J. Hampton, Vice President, Oconee Site
*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 essentially operated at 100% power the entire reporting period.

Unit 2 conducted normal power operations until October 6, 1994, when the generator was taken off line at 12:49 a.m. to begin a scheduled 40-day refueling outage (U2EOC-14). The refueling outage continued throughout the remainder of the reporting period.

Unit 3 essentially operated at 100% power the entire reporting period.

c. Unit 2 Midloop Operation

On October 9, 1994, the inspectors reviewed the licensee's procedure for reduced reactor coolant (RCS) inventory during the Unit 2 outage. The procedure (OP/2/A/1103/11, Draining And Nitrogen Purging Of RC System, revised July 28, 1994) sets forth the requirements for reducing RCS inventory. These include: a minimum of two methods of alarmed level indications utilized to monitor vessel levels; boron concentrations for safe shutdown margin; availability of safety equipment; alignment and tagging of systems and equipment; and two independent RCS temperature indications.

The inspectors verified that the licensee met the requirements specified in the procedure prior to entering a reduced RCS inventory status. The low pressure injection flow rates were being monitored in the control room via the operator aid computer, flow indicators, and alarms on annunciator panel 3SA-3 (windows A8 and A9). RCS temperatures were monitored on the operator aid computer with alarms set at 125 degrees F, on the inadequate core cooling monitor display, and on the control room instrument panel. The RCS levels were monitored by permanent instrumentation (LT-5A and B) and ultrasonic level indicators that were installed temporarily for mid-loop operating conditions. Levels were alarmed and monitored on control room instruments and on the operator aid computer.

In addition, the inspectors verified that configuration control of containment penetrations was maintained. The equipment hatch was only opened during the outage as necessary to move equipment in and out of the reactor building. For the remainder of the time, the hatch remained closed. However, it was necessary for some penetrations to remain open to support the outage work schedule (i.e., cable penetrations for eddy current testing of the steam generator tubes). A required closure time was addressed in the event of a loss of decay heat removal capability.

The licensee maintained a Risk Summary Sheet for the availability of equipment required to support the plant during reduced inventory. This sheet included the status of systems, electrical power sources, RCS makeup supplies, and containment penetrations with the amount of time anticipated for closure. Based on the RCS inventory, the "time to boil" was calculated in the event of a loss of decay heat removal cooling. Overall, the licensee's efforts were determined to be adequate in controlling and monitoring plant conditions while the RCS inventory was maintained at mid-loop.

d. Primary Instrument Air Compressor Fails to Load

On September 28, 1994, the inspector observed the Unit 3 control room operators respond to a drop in the instrument air header pressure. The instrument air header pressure dropped to less than 80 psig, which resulted in an automatic swapover to service air and an automatic start of the auxiliary instrument air compressors. The cause of the drop in air pressure was the failure of the primary air compressor to properly load after it was started following maintenance.

Subsequent to maintenance, the primary air compressor was started and the backup air compressors were secured using OP/0/A/1106/27, Enclosure 4.1. Step 2.20 of Enclosure 4.1 instructed the operator to remove the backup air compressors from service when the primary air compressor parameters were stable. These parameters were listed in step 2.19 of this enclosure. This list of parameters was not sufficient to determine if the primary air compressor was properly loading. For example, the list of parameters in step 2.19 included sump pressure and gave the allowable range as 50 to 130 psig, whereas if the compressor was properly loaded the sump pressure would be greater than instrument air header pressure (approximately 100 psig). The cause of the primary air compressor failing to load was the differential regulators being slightly out of adjustment. The licensee indicated that OP/0/A/1106/27 would be modified to require a sump pressure of between 100 and 130 psig prior to securing the backup compressors. The inspector concluded that the control room operator response to the low header air pressure was good, and that the procedure enhancement was appropriate corrective action.

e. Inadvertent Venting of the Unit 2 Quench Tank

An inadvertent venting of the Unit 2 quench tank occurred on October 17, 1994, at approximately 3:00 a.m., as indicated on the air ejector offgas radiation monitor RIA-40. This was subsequently determined to have resulted from operator activities that were in progress to fill the shell side of the 2A Steam Generator (SG). This evolution required the SG shell side vents be opened to the quench tank. At the same time, the feedwater and steam side of the steam generators were at 29" of vacuum. RIA-40 stayed in the alarm condition with the counts decreasing for approximately 50 minutes. The licensee was unaware that the alarm condition was due to this evolution.

RIA-40 alarmed again at approximately 2:00 p.m., on October 17, 1994, during the filling of the 2B SG from the 2A SG (shell side vents open to the quench tank). RIA-40 counts were decreasing at

3:00 p.m., when valve 2GWD-1 was opened to vent the pressurizer to the quench tank as required by the procedure for reducing the RCS inventory. At this time, RIA-40 alarmed again and it was noticed that the pressure in the pressurizer had reduced, but the pressure in the quench tank had not increased as expected. As a result, the Senior Reactor Operator had the shell side vents on SG 2B closed and the quench tank pressure began to increase. The RIA-40 alarm subsequently cleared. It was determined that when the shell side SG vents were open to the quench tank, existing gas was being drawn into the main condenser and to the atmosphere through the steam jet air ejectors and the Unit 2 vent stack.

The inspectors will review the events that were in progress which may have contributed to the failure to detect and correct this condition in a timely manner. This item will be tracked as Inspector Followup Item (IFI) 270/94-32-01: Failure to Detect Inadvertent Quench Tank Venting.

f. Inoperable Containment Isolation Valve

On October 5, 1994, the licensee torqued the body to bonnet joint on valve 1RC-7 to 125 percent of its normal torque value due to a body to bonnet leak. Valve 1RC-7 is the outboard pressurizer sample containment isolation valve. The maintenance activity was conducted per Work Order 94068251, Task 01. The work activity was commenced at approximately 8:30 a.m. and was completed at approximately 10:37 a.m. Prior to performing the work activity the operators in the control room asked the maintenance technicians performing the work if post maintenance testing of the valve was required. They were assured that testing would not be required. At approximately 5:00 p.m., on October 5, 1994, a performance planner requested that valve 1RC-7 be stroke tested to verify operability of the valve following the maintenance activity. The control room operators declared the valve inoperable and isolated the containment penetration and deactivated the valves upstream of valve 1RC-7 until the required post maintenance testing could be performed. The valve was stroke tested satisfactorily; however, a question remained as to whether a leak test was required to return the containment penetration to an operable status. Subsequent review by the licensee determined that a local leak rate test was not required based on the work activity performed on the valve. The valve was declared operable on October 7, 1994.

The licensee determined that the failure to declare valve 1RC-7 inoperable prior to performing the maintenance activity was a result of the maintenance planners entering a not applicable (N/A) statement on the Post Maintenance Testing (PMT) sheet. The work order identified that a functional test, stroke test, and leak rate test was required. The planners marked the signoffs on the PMT sheet not applicable (N/A) because they stated that the required tests would be documented on separate task sheets;

therefore, the N/A(s) were utilized to indicate that no signatures were required on the PMT sheet. The maintenance technicians assumed that the N/Aed steps meant that post maintenance testing was not required.

A Licensee Event Report (LER) will be submitted to the NRC in accordance with the requirements of 10 CFR 50.73. Also, as a result of this problem, the licensee instituted the following corrective actions:

(1) Work orders planned after October 12, 1994, contain a cross reference statement on the PMT sheet that links the controlling task to the supporting tasks that will perform each retest.

(2) Work orders planned prior to October 12, 1994, but not scheduled, were reviewed and the N/A(s) struck through and a cross reference inserted.

(3) Maintenance personnel were informed that N/A(s) on the Post Maintenance Test Sheet does not indicate that the test is not required.

The failure to declare valve 1RC-7 inoperable and perform the required post maintenance testing is considered a licensee identified violation. However, this violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B of the Enforcement Policy. Accordingly, it will be identified as Non-cited Violation (NCV) 50-269/94-32-02: Inoperable Containment Isolation Valve Due to Maintenance Error.

Within the areas reviewed, one NCV was identified.

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 (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.

The following maintenance activities were observed or reviewed in whole or in part:

(1) Integrated Control System Feedwater Control, B Loop, IP/0/B/0325/002

On October 13, 1994, the inspectors witnessed a calibration that was in progress on the Unit 2 feedwater main and startup valve control system. Problems were experienced in that the control module did not duplicate the bench calibration after it was reinstalled in the panel. As a result, the module was replaced with a new module. Performance of the activity was in accordance with the procedure and the effort was determined to be acceptable.

(2) Install and Reconnect 2LPSW-15, Work Order 94082562, Task 05

On October 29, 1994, the inspectors observed portions of the work activities associated with the reinstallation of Low Pressure Service Water valve 2LPSW-15. The inspectors reviewed the work order for adequacy and observed the completion of the work activity. No deficiencies were noted.

(3) Engineered Safeguards System Analog Channel B Reactor Coolant Pressure Channel Calibration, IP/0/A/0310B/004B

The licensee received a Unit 2 Engineered Safeguards (ES) actuation on October 21, 1994 during the performance of procedure IP/0/A/0310/004B. While calibration of channel B was in progress, channel A was inadvertently placed in the "range" position as opposed to channel B as required by step 10.7.3.a of the procedure. (Note: The procedure referred to the switches as A and B and the panel was labeled as channels 1 and 2). As a result of the event the licensee generated Problem Investigation Report 2-094-1493, which required an evaluation and corrective actions.

Having the two analog channels in a test status simultaneously resulted in the ES Actuation. The major events resulting from the actuation were:

- Emergency start of Keowee Units 1 and 2
- The containment purge tripped due to purge valves PR-2 through PR-5 going shut
- Low pressure service water pumps B and C started

Other ES devices actuated, but the equipment was out of service as a result of the refueling outage and the components did not start or realign.

The failure to place the proper switch to the required position as specified by the procedure is identified as Example 1 of Violation 270/94-32-03: Failure To Follow Procedures.

(4) AC Watt Transducer, Two Element, IP/0/A/3955/01

On October 26, 1994, switchgear 2TE experienced an inadvertent undervoltage trip condition as a result of testing errors during testing of transducer 2ET42. The maintenance technicians failed to remove the test leads attached to the terminal block prior to reclosing the link and repowering the circuitry that had been taken out of service for the test. As a result, the test leads made a path to ground through the test equipment and resulted in blowing a fuse in the 2TE switchgear when the circuit was repowered. Step 10.7.17 of IP/0/A/3955/01 removes the test equipment prior to restoring the plant equipment to service. Although no signoff was required procedurally for performing this step, the requirements for performing the activity were explicit..."Remove test equipment." Failure to comply with the requirements of the procedure is identified as Example 2 of Violation 270/94-32-03: Failure To Follow Procedures.

(5) 2DIA Static Inverter Replacement, TN/2/A/288 1/0/AL1

On October 17, 1994, the inspectors observed the installation of the power cables, ground cable, and alarm circuitry wiring on the new 2DIA Static Inverter. The inspectors verified that the work was conducted under an approved procedure and that the as-left wiring was consistent with design drawings. All activities observed were satisfactory.

(6) Investigate Slow Stroke Time for 3BS-1, Work Order 94079209, Task 01

On October 16, 1994, motor operated valve 3BS-1 failed to satisfy performance stroke testing requirements. 3BS-1 is the 3A reactor building spray pump's discharge isolation valve, and is given an automatic open signal as part of an Engineered Safeguard (ES) actuation. The performance test measured an open stroke time of 14 seconds, as measured on a stopwatch. The acceptance criteria per PT/3/A/0150/22A was 9 to 13 seconds. The acceptance criteria was based on a baseline value of 11 seconds. The Final Safety Analysis Report (FSAR) indicates that this valve is assumed to open within 15 seconds. The licensee initially declared 3BS-1 inoperable and entered the seven day LCO for an inoperable train of building spray. The licensee performed electrical and mechanical preventive maintenance on the valve operator, including cleaning contacts and stem lubrication. Multiple stroke tests were subsequently performed utilizing a Motor Power Monitor (MPM) to precisely measure the stoke time. A total of five MPM tests were performed and the stroke time was consistently 13.5 plus or minus 0.1%. Based on this, the licensee concluded that the valve was not currently degrading and would meet the 15 second FSAR limit. Consequently, the LCO was exited. The licensee believed that maintenance performed during January 1994, which included limit switch adjustment, may have altered the baseline for this valve and that this would account for the slower stroke time. The licensee indicated that they would perform weekly stroke tests to confirm that the valve was not degrading. The inspectors observed various portions of the licensee's troubleshooting efforts including two of the MPM stroke tests. The inspectors concluded that the licensee's actions were acceptable.

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.

The following surveillance activities were observed or reviewed in whole or in part:

(1) Control Rod Movement, PT/0/A/600/15

The inspectors witnessed performance of Unit 1 Control Rod Drive (CRD) movement on October 6, 1994. The purpose of the procedure was to test CRD operation under actual operating conditions by moving each rod group a minimum of 2.5 percent of full travel. This test met the monthly surveillance requirements as specified in Technical Specification 4.1.2.

The operators performed the rod movements per the procedure and were cognizant of plant operating status during the test. The activity was determined to be performed to acceptable standards.

(2) Reactor Building Spray Pump Test, PT/1//A/0204/07

Portions of the reactor building spray pump test were witnessed by the inspectors on September 27, 1994. The quarterly test was necessary to satisfy TS 3.3.2, 3.3.6, 4.0.4. and 4.5.2, as well as Subsections IWP and IWV of Section XI to the ASME Code. The performance test demonstrates operability of the system. During testing of the 1B Pump, high vibration was detected and determined to be in the alert range. The pump was determined to be operable, but the testing frequency was changed and the test will be performed at 2 times the normal frequency.

As each pump was taken out of service, the appropriate Limiting Condition for Operation was entered as required per step 6.1 of the test procedure. The conduct of testing was viewed by the inspectors as a strength.

(3) Control Room Pressurization Test, PT/1&2/A/0170/03

The inspectors observed portions of this performance test conducted on October 26, 1994. This test implements the surveillance requirements of Technical Specification 4.12.1. The inspectors verified that the procedural acceptance criteria was met.

(4) Unit 2 Main Feeder Bus 2 Lockout Test, TT/2/A/610/14

The inspectors observed portions of this temporary test procedure conducted on October 26, 1994. This test procedure verified that the Unit 2 Main Feeder Bus 2 lockout relays operated properly. This test had not been performed on Unit 2 prior to its performance on October 26, 1994. During performance of the test, the startup breaker (E2) failed to trip open when the 86B2 lockout relay was actuated. Investigation by the licensee determined that physical interference with the wiring connected to the contact terminal prevented the actuation contact from closing. The wiring interference was corrected and the test was completed without further problems.

The licensee visually inspected the Unit 3 lockouts to verify that adequate clearance existed between the terminal lugs and the moving contacts. The Unit 1 main feeder bus lockout relays had been tested during the previous Unit 1 refueling outage without incident. In spite of the identified problem, the licensee determined that the Unit 2 Main Feeder Bus had been operable based on the fact that the startup breaker's redundant trip coil had been operable and would have operated to open the breaker if an actual fault had occurred on the Main Feeder Bus.

(5) Unit 2 Control Rod Drive Drop Test, IP/0/A/330/03A

Drop time testing of the Unit 2 control rods was performed on October 6, 1994. The unit was shutdown for refueling outage EOC14 with the reactor coolant system at 532 degrees F and all 4 reactor coolant pumps running. Results of the test showed that rod #3 in group #1 dropped at 1.803 seconds, which was slower than the TS limit of 1.66 seconds. As a result, a second rod drop test was performed and the same rod (rod #3) dropped at 1.758 seconds. Results of the second test also showed a second rod, rod #4 in group #1, to have increased in drop time to greater than the TS limit. Rod #4 dropped at 1.662 seconds and was the only rod which increased in drop time from the first to the second test.

A summary of the test results indicated that the drop times for an additional 8 rods were slow enough (i.e., greater than 1.40 seconds) to generate doubt that they may not meet

TS requirements after operating for another fuel cycle (approximately 18 months). One of these rods, rod #1 in group #1, which dropped at 1.417 seconds during the first test and at 1.328 seconds during the second test, was evaluated by the licensee and determined not to be a problem during the next fuel cycle. Past operating history of the rod was reviewed and was considered as part of the operability evaluation.

The slow rod drop times were determined to be a result of erosion material build-up in the area of the ball checks in the thermal barrier cooler. The ball checks are required to raise off their seat to allow RCS coolant flow to enter and replace the void created in the housing when the rods fall into the core.

As a result, the thermal barrier coolers were replaced in 8 of the drive shaft housing assemblies with a modified cooler (modified type A) that increased clearances in the area of the ball check valves. The 9th assembly was replaced with a spare rod drive shaft housing assembly that had been cleaned and restored to the original clearances.

A statistical analysis was done on the Unit 1 control rods. The analysis indicated that continued operation of Unit 1 would not result in rod drop times greater than Technical Specification allowable values. However, the licensee indicated that the operability of the Unit 1 rods would be reassessed in April 1995.

The thermal barriers in the Unit 3 CRD shaft housing assemblies are type C. There have been no reported problems with CRD drop times associated with ball checks in the type C thermal barrier coolers.

(6) Turbine Driven Emergency Feedwater Pump Test, PT/1/A/0600/12

On September 26, 1994, the inspectors witnessed performance testing of the Unit 1 turbine driven emergency feedwater pump. The test was required to be performed quarterly as specified per TS to satisfy the American Society of Mechanical Engineers (ASME), Section XI requirements. The applicable sections of the TS which relate to pump operability and stroke testing of valves were 3.4, 4.0.4, and 4.9.

Personnel performing the test were knowledgeable of the operation of the equipment and their performance was determined to be very good.

(7) Operation of the SSF Diesel Generator, OP/0/A/1600/10

On October 3, 1994, the inspectors witnessed post maintenance testing of the Safe Shutdown Facility (SSF) Diesel Generator. The inspectors noted that step 2.15 of the test procedure required that the Diesel Engine Log Book be referenced to determine if the diesel had been operated less than 700 KW for greater than 2 accumulated hours, in order to determine if the engine needed to be "desouped" (a procedure that involves burning out deposits in the exhaust manifold). The inspectors reviewed the Diesel Engine Log Book and noted that the information included was inadequate to determine the exact amount of time the engine had been operated at less than 700 KW. The licensee agreed that the Diesel Engine Log Book did not contain sufficient detail to comply with step 2.15, but stated that they had been informed by the diesel manufacturer some time ago that the desouping procedure was not necessary. However, they had neglected to remove this step from the procedure. The inspector concluded that this represented a weakness in the licensee's procedure. The licensee indicated that step 2.15 would be deleted. All other aspects of the procedure were satisfactory and the diesel and its support equipment met all acceptance criteria.

(8) Low Pressure Injection Pump Test, PT/3/A/0203/06A

On October 4, 1994, the inspectors witnessed the performance of the quarterly operability test of the 3A Low Pressure Injection (LPI) Pump. The indicated developed head for the pump was 186 psid, according to instrument 3PG-21. This exceeded the acceptance criteria of 158.5-181.5 and would have placed the pump in the alert range. However, the difference between the indicated pressure on the suction and discharge gages was 174 psid. Therefore, the licensee concluded that instrument 3PG-21 was out of calibration and the developed head of the pump was within the acceptance criteria. The inspectors agreed with the licensee's conclusion and determined that all activities observed were satisfactory. The licensee plans to recalibrate 3PG-21 prior to the next performance of the procedure.

(9) Turbine Stop Valve Movement Test, PT/0/A/290/04

The inspectors witnessed the monthly test of the Unit 3 main steam stop valves as required by TS 4.1. This test closed each valve approximately 10% in order to verify valve movement locally and via the control room meter. All activities observed were satisfactory.

Within the areas reviewed, one violation with two examples was 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. Turbine Bypass Isolation Test, TT/2/B/0251/46

The inspectors witnessed testing activities to evaluate leakage through the Unit 2 turbine bypass valves. The test was performed in accordance with test procedure TT/2/B/0251/46, Turbine Bypass Isolation Test. The test consisted of evaluating plant MWe output and condenser vacuum during closure and reopening of the block valves to each of the bypass valves. The test data was taken via the operator aid computer and was utilized to determine the need for bypass valve maintenance or replacement during the Unit 2 refueling outage.

Performance of the testing activities was considered to be acceptable.

b. 10CFR Part 21 Review

The inspectors reviewed a 10CFR Part 21 issue, identified by Dresser-Rand dated August 5, 1994, that related to a deficiency with the Gimple trip throttle valve on the turbine driven auxiliary feedwater pump at Davis-Besse Unit 1. The reported deficiency was that the coupling set screw on the trip throttle valve had not engaged the valve stem and therefore, the stem travel was impaired.

The Duke Power General Office reviewed the subject report and determined that Gimple valves were utilized at their Catawba and McGuire Nuclear Stations. As a result, problem identification report (0-G94-0365) was issued to initiate preventative measures at those sites. However, the licensee determined that Gimple valves did not exist at the Oconee Nuclear Station and no corrective actions were necessary.

The inspector verified that General Electric turbines were installed at the Oconee Nuclear Station and that Gimple valves were not utilized.

No violations or deviations were 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:

radiological controls; radiological effluent, waste treatment, and environmental monitoring; physical security, and fire protection.

a. Radiation Protection

During a tour of the turbine building on October 11, 1994, the inspectors noticed maintenance personnel crossing the yellow/magenta ropes set up to identify a radiation controlled zone (RCZ) at main steam reheater 2B2. When the maintenance personnel were questioned, they informed the inspectors that health physics (HP) personnel had informed them that it was not necessary to comply with the rules established for an RCZ since no radiation hazard existed until the manways were removed from the heater.

The area HP was summoned to the area and it was verified that the maintenance personnel had been told that the yellow/magenta ropes were to be ignored until the manways were removed. The HP informed the inspectors that the RCZ was set up in advance to get a "head start" on the outage effort.

The licensee's directive, Radiation Protection, Directive No. III-3, Posting of Radiation Control Zones, requires that an RCZ be identified with a yellow/magenta rope with placards attached indicating the requirements for entering the zone. Although the placards had not been installed, the inspectors determined that allowing personnel to cross back and forth across the yellow/magenta ropes was a poor practice and a weakness in the Health Physics Program. The inspectors had identified this poor practice during a previous refueling outage. At that time, the licensee agreed to caution workers to treat all RCZ ropes as boundaries at all times.

After bringing this latest observation to the attention of licensee management, the inspectors were assured that the practice would be corrected. The inspectors observed various RCZs throughout the remainder of the reporting period and did not identify any instances where the yellow/magenta ropes were being ignored.

No violations or deviations were identified.

6. Exit Interview

The inspection scope and findings were summarized on November 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
50-270/94-32-01	IFI: Failure to Detect Inadvertent Quench Tank Venting (paragraph 2.e).
50-269/94-32-02	NCV: Inoperable Containment Isolation Valve Due to Maintenance Error (paragraph 2.f).
50-270/94-32-03	VIO: Failure to Follow Procedures - Two Examples (paragraph 3.a).