UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-269/82-30, 50-270/82-30, and 50-287/82-30

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

Facility Name: Oconee Nuclear Station

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

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

Inspection at Oconee site near Seneca, Carolina

Inspectors: A. J. Ignatonis for — W. Orders — 9/2/82 Date Signed

A. J. Ignatonis for — D. Falconer — 9/2/82 Date Signed

Approved by: A. J. Ignatonis for — J. C. Bryant, Section Chief, Division of Project and Resident Programs — 9/2/82 Date Signed

SUMMARY

Inspection on July 16 - August 10, 1982

Areas Inspected

This routine, announced inspection involved 204 resident inspector-hours on site in the areas of operations, surveillance testing, maintenance, NUREG 0737 modifications and refueling activities.

Results

Of the five areas inspected, no items of noncompliance or deviations were identified.

DETAILS

1. Persons Contacted

Licensee Employees

*J. Ed Smith, Station Manager
J. N. Pope, Superintendent of Operations
T. B. Owen, Supervisor of Technical Services
J. Vaughn, Supervisor of Mechanical Maintenance
R. Rogers, Licensing & Project Engineer
*T. Matthews, Licensing Engineer

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

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on August 13, 1982, with those persons indicated in paragraph 1 above. The licensee voiced cognizance and concern over the findings contained herein.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items were not identified during this inspection.

5. Plant Operations

The inspector reviewed plant operations throughout the report period, July 16 - August 10, 1982, to verify conformance with regulatory requirements, technical specifications and administrative controls. Control room logs, shift supervisor logs, shift turnover records and equipment removal and restoration records for the three units were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel on day and night shifts.

Activities within the control rooms were monitored during all shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in Section 3.18 of the Station Directives. The complement of licensed personnel on each shift met or exceeded the minimum required by technical specifications. Operators were responsive to plant annunciator alarms and appeared to be cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured include but are not limited to the following:

Turbine Building

Auxiliary Building

Units 1, 2, and 3 Electrical
Equipment Rooms

Units 1, 2, and 3 Cable
Spreaaing Rooms

Station Yard Zone
Within the Protected Area

Unit 3 Reactor Building

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

Unit 1 began the report period operating at 100 percent power. The unit tripped at 8:25 p.m. on July 29, 1982 due to a lightning strike to the switchyard. During the trip, the main steam safety valves lifted as expected. Reactor coolant pressure remained below the setpoint of the PORV and pressurizer code safety valves, primary and secondary level remained on scale, and no engineered safeguards set points were reached.

The unit was returned to 100 percent power the following day.

Power operation continued at 100 percent until August 6, 1982 when the reactor tripped. The reactor trip was initiated by a variable low RCS pressure, a function of RCS temperature which was caused by the Group 6 control rods dropping into the core during the performance of a rod drive (CRD) power supply test. During the trip, the main steam safety valves lifted as expected. Reactor coolant (RC) pressure remained below the setpoint of the PORV and pressurizer code safety valves, primary and secondary levels remained on scale, and no ES setpoints were reached.

The unit was returned to 100 percent power the following day and operation continued there until the end of the report period.

Unit 2 began the report period operating at 100 percent power. Full power operation continued until the unit was shut down on July 17, 1982 to repair an electro-hydraulic control (EHC) oil leak. The unit was returned to 100 percent power the following day.

On July 22, 1982, the unit tripped due to EHC problems.

During the trip, the main steam safety valves lifted as expected. RC pressure remained below the setpoint of the PORV and pressurizer code safety valves, primary and secondary level remained on scale and no ES set points were reached nor was emergency feedwater initiated.

The Unit was returned to 100 percent power the following day. Power operation continued at 100 percent until the unit tripped at 8:25 p.m. on July 29, 1982 due to a lightning strike to the switchyard. During the trip, the main steam safety valves lifted as expected. RC pressure remained below the setpoint of the PORV and pressurizer code safety valves, primary and secondary level remained on scale and no ES setpoints were reached.

The unit was returned to 100 percent power the following day and power operation continued there until the end of the report period.

Unit 3 began the report period in preparation for unit core reload. On July 23, 1982, repairs to damaged incore guide nozzles, (details in report 82-27) were completed and fuel reload was begun the following day as detailed elsewhere in this report. Refueling was completed on July 29, 1982. The anticipated on line date has been extended to October 27, 1982 due to additional problems identified during auxiliary feedwater modifications as detailed elsewhere in this report.

6. Surveillance Testing

The surveillance tests detailed below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy.

The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration completed and test results were adequate.

The selected procedures perused attested conformance with applicable technical specifications; they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency prescribed.

Procedure	Title
IP/0/A/0203/01C	LPI Pump Flow Instrument Calibration
IP/2&3/B/0202/01I	Letdown System Temporary Instrument Calibration
IP/0/B/0275/05H	EFW System Non-Safety Related Instrument Calibration
IP/0/A/0310/05D	ESS Analog Ch-C Press Switch Contact Buffer Test
IP/0/A/0310/12A	HPI and RB Isolation Ch-1 On-line Test

IP/O/A/0310/12B	LPI Logic Channel-3 on-line Test
IP/O/A/0310/12C	RB Isolation & Cooling Ch-5 On-line Test
IP/O/A/0310/12D	RB Spray Logic Ch-7 On-line Test
PT/1/A/0204/07	RB Spray Performance Test
PT/1/A/0203/06	LP Injection System Performance Test
PT/1/A/0202/11	HP Injection System Performance Test

The inspector employed one or more of the following acceptance criteria for evaluating the above items:

10 CFR
ANSI N 18.7
Oconee Technical Specifications
Oconee Station Directive
Duke Administrative Policy Manual

Within the areas inspected no items of non-compliance or deviations were identified.

7. Maintenance Activities

Maintenance activities were observed and/or reviewed throughout the report period to ascertain that the work was being performed by qualified personnel, that activities were accomplished employing approved procedures or the activity was within the skill of the trade. Limiting conditions for operation were examined to ensure that technical specification requirements were satisfied. Activities, procedures, and work requests were examined to ensure adequate fire protection, cleanliness control and radiation protection measures were observed, and equipment was properly returned to service.

Acceptance criteria employed for this review included but were not limited to:

Station Directive
Administrative Policy Manual
Technical Specifications
Title 10 CFR

Detailed below are selected maintenance activities which were observed and/or reviewed during the report period:

Work Request Number	Component
24265-1	3FDW-65
14897	3HP-31
16583	3LP-61
57838B-1	2A HPI Pump
21567	1CBAST Level Instrumentation
23295	Unit 1 Hotwell Sump Pump
24501	3 HD-157
22246	1RC-160 and 159 Control Relays

Within the areas inspected no items of non-conmpliance or deviations were identified.

8. Unit 3 Refueling

Core loading of the Unit 3, Cycle 7 fuel assemblies was completed on July 29, 1982. The Cycle 7 refueling began on July 24, 1982 and consisted primarily of spent fuel pool-to-reactor vessel moves as a result of the entire Cycle 6 core having been defueled in preparation for the 10 year inservice inspection as detailed in report 82-23.

The Cycle 7 core consisted of 177 fuel assemblies, each of which was a 15 by 15 array containing 208 fuel rods, 16 control rod guide tubes, and one incore instrument guide tube. The fuel consited of dished-end, cylindrical pellets of uranium dioxide clad in cold-worked Zircaloy-4. All fuel assemblies were identical in concept and four regenerative neutron sources were utilized.

The inspectors witnessed fuel handling activites in the control room and containment, and reviewed procedures relating to refueling to verify that activities were being accomplished in accordance with technical specifications, license requirements, and NRC requirements.

No violations or deviations were identified.

9. TMI Action Items

The status of selected TMI action item modifications is categorized below. The completed portions of modifications installed on Unit 3 were verified by the resident inspection staff. The licensee provided the status/delay justifications for these items by letters to the Nuclear Regulatory Commission dated April 16 and July 28, 1982.

II.B.1 Reactor Coolant System Vents

Item II.B.1 requires that remotely operated reactor coolant system and reactor vessel head high point vents be installed. The Oconee design of the RCS high point vent system entails two solenoid operated valves mounted in series on each of the two steam generator piping high points and in the reactor vessel head high point. The resident inspectors verified the installation of the completed portions of this modification on Unit 3.

II.B.3 Post Accident Sampling

Item II.B.3 requires that a design and operational review of the reactor coolant and containment atmosphere sampling systems be performed to determine ability to sample under accident conditions. Should the review reveal that personnel could not promptly and safely obtain samples, additional design features and/or shielding are to be provided.

At Oconee, sampling points have been selected to allow collection of pressurized and unpressurized reactor coolant samples. Pressurized and unpressurized reactor coolant will be collected from the cold leg drain line on each unit. A sump sample will be collected from the low pressure injection system coolers. The pressurized and unpressurized reactor coolant and sump sample lines will be routed to a sampling hood designed to reduce radiation exposures during sample collection.

In addition to the reactor coolant and sump samples, a containment atmosphere sample line will also be routed to this sampling hood. The containment atmosphere sample will be obtained from the hydrogen analyzer sample lines.

The licensee anticipates completing the Unit 3 in-containment portions of the liquid and gas sample systems prior to start-up following the 10 year inservice inspection outage which is currently underway. The remainder of the liquid system will be completed within one month following start-up and the gas system is to be completed by October 30, 1982.

The resident inspection staff verified the installation of the completed portions of the Unit 3 post accident sampling system.

II.F.1(1) Noble Gas Effluent Monitor

Item II.F.1.(1) requires that noble gas effluent monitors be installed with an extended range designed to function during accident conditions as well as during normal operating conditions.

At Oconee, unit vent monitors for nobles gases are to be provided for each unit with a range adequate to cover normal and accident conditions. Three monitors will be required to measure activities form 1 x 10-7 uCI/cc to 1 x 10^5 uCi/cc of noble gases.

Continuous indication of unit vent radiation level and the appropriate alarms will be provided in the Control Room.

Erratic indications from the installed system had necessitated the return of the detector portion to the vendor for modification. All detectors have been modified and returned to Oconee. The licensee anticipates installation of the Unit 1 and Unit 2 detectors by September 30, 1982 and Unit 3 prior to startup following the 10 year inservice inspection which is currently underway.

The resident inspection staff verified the installation of the completed portions of the Unit 3 noble gas effluent monitoring system.

II.F.1.(3) Containment High Radiation Monitor

Item II.F.1.(3) requires that containment radiation-level monitors with a maximum range of 10^8 rad/hr be installed; a minimum of two such monitors that are physically separated be provided; and monitors be developed and qualified to function in an accident environment.

Installation of the Unit 1 monitors is planned for the next refueling outage. Unit 2 monitors are in place as detailed in report 82-15. However, the in-containment splice is not environmentally qualified and the monitors have not been calibrated. The licensee anticipates having the Unit 2 monitors fully operable by the completion of the next refueling outage.

The licensee anticipates completing the Unit 3 installation prior to start-up following the 10 year inservice inspection outage which is currently underway. Calibration will be delayed due to the unavailability of vendor supplied calibration equipment.

The resident inspection staff verified the installation of the completed portions of the Unit 3 system.

II.F.1.9(4) Containment Pressure Monitor

Item II.F.1(4) requires that continuous indication of containment pressure be provided in the control room of each operating reactor. Measurement and indication capability shall include three times the design pressure of the containment for concrete, four times the design pressure for steel, and -5 psig for all containments.

The licensee committed in a letter to NRC staff dated January 2, 1980, to install two identical safety class pressure transmitters to monitor the Reactor Building (RB) pressure and provide signals to Control Room indicators, (one per transmitter), and a shared chart recorder. Each channel will be powered by vital instrument busses. Each transmitter will be located outside the RB and will monitor the pressure with a bellows sensor coupled with a filled capillary tube. Each transmitter will have its own separate independent containment penetration and will be completely independent from the other channel. This instrumentation will meet Regulatory Guide 1.97, dated December 1975.

Each transmitter will monitor a range of -5 psig to 175 psig, a range of three times the RB design pressure.

The resident inspectors verified the installation of the above equipment on Oconee Unit 3.

II.F.1.(5) Containment Water Level Monitor

Item II.F.1.(5) requires that continuous indication of containment water level be provided in the control room for all plants. A narrow range instrument shall be provided covering the range from the bottom to the top of the containment sump. A wide range instrument shall also be provided which shall cover the range from the bottom of the containment to the elevation equivalent to a 600,000 gallon capacity.

At Oconee, the Reactor Building (RB) water level will be monitored by wide range and narrow range systems. The narrow range level transmitters will be qualified to Regulatory Gudie 1.89 (November 1974) criteria. The transmitter shall be powered from the vital instrument busses and will provide Control Room indication and will be monitored by the plant computer. This transmitter shall have a range 0-3' (one foot above the containment floor).

The wide range level monitor shall be qualified to meet Regulatory Guide 1.97 (December 1975) criteria and shall monitor the level from the containment floor to a level of 15' or 600,000 gallons. Each transmitter shall provide control room indication with an input to a shared chart recorder. Each transmitter shall be powered from the vital instrument busses.

The Unit 3 system has been installed, however calibration of the system has not been completed. The resident inspection staff verified the installation of the containment water level monitoring system.

II.F.1(6) Containment Hydrogen Monitor

Item II.F.1.(6) requires that continuous indication of hydrogen concentration on the containment atmosphere be provided in the control room. Measurement capability shall be provide over the range of 0 to 10% hydrogen concentration under both positive and negative ambient pressure.

In a letter to NRC staff dated January 2, 1980, the licensee committed to install two separate identical analyzer systems per unit. These analyzers will operate independently of the recombiner system and will be supplied by vital sources of power. Each analyzer will be able to monitor either of two identical containment sampling headers or the calibration gases. Each analyzer shall have, along with control panel indicator and alarm, a separate control room indicator and alarm with a shared chart recorder.

Each containment sample header will have five inlet samples available for monitoring:

1. Top
2. Operating Level
3. Basement
4. Radiation Monitor/Recombiner Inlet header
5. Radiation Monitor/Recombiner Discharge header

Sample selection and switching is accomplished manually by the operator from the remote analyzer control panel. Each analyzer shall have its own sample and return containment penetrations.

Problems with the Conoflow pressure regulators used in the Comsip Hydrogen Analyzer had delayed implementation of this system. Those problems have been corrected and the licensee anticipates completion of the Unit 1 and Unit 2 systems by September 30, 1982 and Unit 3 by start-up following the inservice inspection outage which is currently underway.

The resident inspection staff verified the installation of the completed portions of the unit 3 containment hydrogen monitoring system.

10. Emergency Feedwater Header Replacement

As previously reported, due to the discovery of damage to the OTSG Internal Auxiliary Feedwater (AFW) Headers at Davis Besse (Toledo Edison) and Rancho Seco (Sacramento Municipal Utility District) the decision was made to shut down Unit 3 on the evening of April 23, 1982 and begin a refueling outage earlier than planned. (Units 1 and 2 utilize an external AFW header and were not subject to this damage.) Damage discovered somewhat similar to that reported by Davis Besse and Rancho Seco was discovered.

The repair efforts entail stabilizing the internal header in place and blank flange the existing AFW nozzle. The internal header would serve then mainly as an extension of the shroud and would maintain steam cross flow at the present distance above the 15th TSP.

To stabilize the internal header, six holes were drilled through the steam generator shell and shroud near each dowel pin and bracket location (except bracket numbers 2 and 3 which can be reached from the manway). The dowel pins were removed. All loose parts will be recovered. The internal header will be jacked up slightly to remove any internal brackets not securely fastened. The internal header will then be centered on the shroud and welded to the shroud through the six holes and the existing manway.

The six holes drilled in the steam generator shell and shroud for header stabilization work will also be used as points of injection for an external AFW ring header. The design of the external header system is very similar to the design utilized on Oconee 1 and 2. The design includes an external ring header with six J-pipe risers feeding into the steam generator through thermal sleeves, directly into the tube bundle. The main difference between the external AFW header system to be installed on Oconee 3 and the ones utilized on Oconee 1 and 2 is a new thermal sleeve design which should help eliminate the thermal sleeve cracking problem experienced on the old design.

At the close of report period 82-27 all the holes had been drilled on both steam generators, the "B" internal header had been stabilized and the "A" header was being repaired. Due to additional damage found on the A header, more extensive re-enforcement was deemed necessary as detailed below.

Significant circumferential cracks were identified at the junctures of the vertical and horizontal plate pieces forming the header. In order to re-enforce the header, fifteen L-shaped access windows will be cut in the outside and bottom surfaces of the header. Two bulkheads, each the size of the cross sectional areas of the header will be welded in place at each of the window locations, and the L-shaped section will be welded back in place.

At the close of this report period, one window location has been completed. The current projected on-line date is October 24, 1982.

The resident inspection staff will continue to monitor the repair effort.

11. Bulletins and Circulars

The following bulletins were transmitted for information only and/or were not applicable to B&W utilities and as such do not require a licensee response.

IEB 78-14: Deterioration of Buna-N Components in ASCO Solenoids.

IEB 79-06: Review of Operational Errors and System Misalignments Identified During the TMI Event.

IEB 79-08: Events Relevant to Boiling Water Power Reactors Identified During Three Mile Island Incident.

IEB 79-12: Short Period Scrams at BWR Facilities

IEB 79-26: Boron Loss From BWR Control Blades.

These items are closed.

IEB 80-18, Minimum Flow through Charging Pumps: The Licensee response to this bulletin, dated August 7, 1980, was reviewed by the resident inspector. The minimum flow lines for the Oconee HPI pumps are always open during normal operation, are not isolated by a Safety Injection (SI) signal, and therefore are always available during all conditions requiring SI. In addition, each minimum flow line serves as a protection for its HPI pump against "dead heading" in the event that the discharge line is isolated with the pump operating. Cooling of the pump motor is provided separately by the Low Pressure Service Water System.

The HPI flow for each pump assumed in the Oconee safety analyses was based upon a value of HPI flow measured downstream of the minimum flow line, with the minimum flow line in its normal open state. Thus, the presence of the HPI minimum flow line and its state are of no consequence to the applicability of these safety related analyses.

This item is closed.

IEB 79-24 Frozen Lines

The licensee response dated September 27, 1979 was reviewed and appeared adequate. All lines at Oconee to which this bulletin applies were inspected by the licensee. Any lines exposed to freezing weather were verified to have operable heat tracing and, with one exception, all insulation in place. The Unit 3 Borated Water Storage Tank (BWST) inlet pipe had insulation removed for ultrasonic testing; the insulation was subsequently replaced.

This item is closed.

The licensee acknowledged the receipt and evaluation of the following IE Circulars:

78-15	Tilting Disc Check Valve Failure to Close With Gravity
30-01	Service Advice for GE Induction Disc Relays
80-02	Nuclear Power Plant Staff Work Hours
80-03	Protection from Toxic Gas Hazards
80-04	Securing of Threaded Locking Devices on Safety-Related Equipment
80-05	Emergency Diesel-Generator Lubricating Oil Addition and Onsite Supply
80-07	Problems with HPCI Turbine Oil System
80-09	Problems With Plant Internal Communications Systems
80-10	Failure to Maintain Environmental Qualification of Equipment
80-11	Emergency Diesel Generator Lube Oil Cooler Failures

80-13	Grid Strap Damage in Westinghouse Fuel Assemblies
80-15	Loss of Reactor Coolant Pump Cooling and Natural Circulation Cooldown
80-16	IE Circular No. 80-16, Operational Deficiencies in Rosemount Model 510DU Trip Units and Model 1152 Pressure Transmitters
80-17	Fuel Pin Damage Due to Water Jet from Baffle Plate Corner
80-21	Regulation of Refueling Crews
80-22	Confirmation of Employee Qualifications
81-12	Inadequate Periodic Test Procedure in PWR Protection System
81-13	Torque Switch Electrical Bypass Circuit for Safeguards Service Valve Motors
81-14	Main Steam Isolation Valve Failures to Close.

These items are closed.