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

Report Nos. 50-269/81-04, 50-270/81-04 and 50-287/81-04

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

Facility Name: Oconee

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

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

Inspection at Oconee site near Seneca, South Carolina

Inspectors: AHJohnson for — 3/25/81
F. Jape, Senior Resident Inspector — Date Signed

AHJohnson for — 3/25/81
W. Orders, Resident Inspector — Date Signed

AHJohnson for — 3/25/81
D. Myers, Resident Inspector — Date Signed

Approved by: JBryant — 3/26/81
J. Bryant, Section Chief, Division of Resident and Reactor Project Inspection — Date Signed

SUMMARY

Inspection on February 2, 1980 through March 10, 1981.

Areas Inspected

This routine inspection involved 485 resident inspector-hours on site in the areas of plant operations, surveillance testing, maintenance observation, station modifications, emergency power tests, steam generator overpressurization, reactor trip, radiological survey, integrated leak rate test, licensee corrective actions, steam generator tube plugging, and followup on unresolved items.

Results

Of the 12 areas inspected, no violations or deviations were identified in 7 areas; 6 violations were found in 5 areas (Violation - Failure to report reactor trip, paragraph 11.b; Violation - Failure to follow procedure resulting in load shed, paragraph 9; Violation - Failure to label radioactive waste, paragraph 13; Violation - Overpressurization of steam generator, paragraph 10; Violation - Failure to survey and post a contaminated area, paragraph 13; Violation - Failure to follow procedures resulting in uncontrolled RCS level decrease, paragraph 12).

8106100244

DETAILS

1. Persons Contacted

   Licensee Employees

   *J. E. Smith, Station Manager
   *J. M. Davis, Superintendent of Maintenance
   *J. N. Pope, Superintendent of Operations
   *T. B. Owen, Superintendent of Technical Services
   *R. T. Bond, Licensing and Projects Engineer
   *T. Cribbs, Licensing Engineer

   Other licensee employees contacted included 17 operations personnel, 8 technicians, 15 operators, 6 mechanics, 9 security force members, and 5 office personnel.

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on March 6, 1981, with those persons indicated in Paragraph 1 above. The Violations described in paragraphs 9, 10, 11, 12 and 13 were discussed with licensee management who acknowledged them. Other inspection findings were acknowledged without significant comment.

3. Licensee Action on Previous Inspection Findings

   (Closed) Unresolved Item (287/80-25-03) Review of licensee and vendor supplied certification/data and review of the associated analysis reveals that RPS transmitters located inside the reactor building are not subjected to environments which surpass their qualifications. Licensee analysis also indicates initial reactor building temperature does not significantly affect post LOCA building pressure. Details follow in paragraph 19.

   (Closed) Unresolved Item (269/80-30-01) The inspector discussed with the licensee the practice of storing aluminum ladders within the reactor containment building. The chemical reaction of aluminum with boric acid is exothermic and results in byproduct generation of hydrogen. The safety implications associated with hydrogen production inside containment prompted the licensee to initiate the practice of removing all aluminum ladders from reactor buildings at the conclusion of each outage.

4. Unresolved Items

   Unresolved items were not identified during this inspection.

5. Plant Operations

The inspector reviewed plant operations throughout the report period, to verify conformance with regulatory requirements, technical specifications and administrative controls. Control room logs, shift supervisors logs, shift turnover records and equipment removal and restoration records for the three units were continually 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 activities observed were conducted as prescribed in applicable Station Directives. The complement of licensed personnel on each shift met or exceeded the minimum required by TS 6.1.1.3. Operators were responsive to plant annunciator alarms and appeared cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a continual 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 Spreading Rooms

Station Yard Zone within the protected area

Units 1 and 3 Reactor Buildings

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

Oconee Unit 1 operated at approximately 85% FP from February 1 through 6, at which time the Unit was shut down to repair a steam generator tube leak. Details of the tube plugging efforts are in paragraph 17.

Following completion of the tube plugging effort, Intersystem LOCA performance testing revealed that Core Flood valve CF-12 leaked. Details of the repair of CF-12 are in paragraph 7. Following CF-12 repair, Unit 1 started up March 3, and is, at the close of this report, at full power.

Oconee Unit 2 operated throughout the reporting period at approximately 73% FP on three Reactor Coolant Pumps (RCP); RCP 2B1 was removed from service on January 31, 1981, due to a high bearing temperature. No other significant operational problems evolved aside from a Reactor Trip which occurred on February 11. Details of the trip are in paragraph 11.

Oconee Unit 3 remained in a refueling outage throughout the reporting period. An Integrated Leak Rate Test was successfully performed on the Reactor Building; details follow in paragraph 14.

6. Surveillance Testing

The surveillance tests detailed below were analyzed and 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	Unit
PT/0/A/0150/08A	Reactor Building Personnel Lock Leak Rate Test	1
PT/1/A/150/15D	Intersystem LOCA Leak Test	1
PT/0/A/150/23	HPI System Leakage	1
PT/0/A/201/04	P.O.R.V. Operability Test	1
PT/3/A/203/06	LPI System Performance Test	3
PT/3/A/600/11	Emergency Feedwater Performance Test	3
IP/1/A/305/3A	RPS CH-A On-Line Test	1
IP/2/A/305/3C	RPS CH-C On-Line Test	2
IP/3/A/305/3D	RPS CH-D On-Line Test	3
IP/0/A/310/12A	HIP and RB Isolation CH#1 On-Line Test	1
IP/1/A/310/13C	RB Isolation and Cooling CH#6 On-Line Test	1
PT/0/A/600/18	Emergency Feedwater Train Operability Test	1

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 violations or deviations were identified.

7. Corrective Maintenance Observations

Maintenance activities were observed and reviewed throughout the inspection period to verify that activities were accomplished using approved procedures and the work was done by qualified personnel. Where appropriate, limiting conditions for operation were examined to ensure that while the equipment was removed from service the appropriate requirements of the technical specifications were satisfied. The following were used as acceptance criteria:

-- Station Directives 3.3.1, 3.3.2, 3.3.5, 3.3.11 and 3.3.15.
-- Administrative Policy Manual, Sections 3.3 and 4.7.

Maintenance activities observed were as follows:

a. Repair of CF-12, Unit 1

In response to the February 23, 1980, NRC generic letter regarding intersystem LOCA, DPC has established a program for leak testing core flood valves and low pressure injection check valves. On February 22, 1981, during performance of the check valves leak test, PT/1/A/150/15D, CF-12 was determined to be leaking excessively. Five other check valves, CF-11, -13, -14, LP-47 and -48 were determined to be acceptable.

Repair and subsequent retesting of CF-12 were observed by the inspector. The job required draining the primary system to a level so the valve could be disassembled. A temporary sight glass was installed to ensure accuracy of the RC level during the job and to avoid spilling RC water onto the workman. The work was done as authorized by Work Request 12335, and using procedure MP/0/A/1200/58.

The valve hinge and disc were removed for future examination to determine the failure cause. New components were installed and the valve retested satisfactorily on March 2, 1981.

The event report is scheduled to be submitted on March 6, 1981, pursuant to Technical Specification 6.6.2.1(a)9.

b. RC Pump Closure Stud Examination

Information Notice 80-27, Degradation of Reactor Coolant Pump Studs, and NSAC/INPO Notepad item prompted as examination of closure studs. This work was completed for Unit 1 on February 11, 1981 and for Unit 3 on February 4, 1981. The inspection for Unit 2 is scheduled for the March maintenance outage.

The inspection of Unit 1 RCP studs indicated no significant corrosion. Some corrosion was observed on all four Unit 3 RCP studs.

To determine the extent of the Unit 3 problem the exposed section of the studs were cleaned and measurements taken. The inspector witnesses this activity.

Review of this data revealed one stud on 3A1 pump did not meet minimum acceptance diameter. Procedures were developed to replace this stud. The job was completed successfully on February 10, 1981.

This maintenance activity was authorized by Work Request 51502, TM/3/A/4000/86 and TM/3/1/4000/87. The inspector visited the job site and interviewed workmen periodically to verify adherence with procedures and radiological controls.

Within the area inspected, no violations were identified.

This event is reportable pursuant to Technical Specification 6.6.2.1a(3) and has been assigned LER number RO-287/81-2 by the licensee.

c. Snubber Inspections - Unit 3

Technical Specification 4.18 requires a periodic visual inspection and functional testing of snubbers. This was performed on inaccessible and accessible snubbers during the fifth refueling outage on Unit 3. The records and results of this maintenance activity were examined by the inspector. No problems were reported.

The inspector also independently conducted a visual inspection of selected snubbers on the pressurizer relief lines, reactor coolant pumps, low pressure injection lines and steam lines. All were found acceptable and in agreement with the craftsman's data. A re-inspection of selected snubbers was done by both the licensee's personnel and the inspector following completion of maintenance work within the reactor building. No problems were identified.

Eleven snubbers were removed for bench testing. All passed the required functional tests. Three of these snubbers were examined by the inspector to ensure they were properly installed. No problems were identified.

8. Nuclear Station Modifications

The inspector reviewed changes to selected station safety-related systems to ensure that modifications were reviewed and approved in accordance with 10 CFR 50.59; that changes were controlled by established approved procedures and satisfactorily tested; that operating procedures and affected system diagrams were properly updated. The Duke Power Administrative Policy Manual Section 4.4 defines the basic requirements concerning administration of Nuclear Station Modifications (NSM). Of the two major NSM's reviewed, no violations were identified.

The NSM's reviewed in detail were:

a. NSM 1487 Reactor Cavity Seal Ring

The NRC expressed concern, in a generic letter, dated July 18, 1979, to all licensees, over the storage location of the reactor cavity annulus seal ring. The concern was the potential for the seal ring to become a destructive missile in the event of a loss-of-coolant accident inside the reactor cavity.

To resolve this concern, DPC has prepared modification 1487 to remove the seal ring and store it in a location where it will not become a missile hazard. The work was to be completed during the scheduled refueling outages.

Followup on this item has been completed. Work has been satisfactorily completed on all three units as follows:

Unit 1	February 1980	Refueling Outage
Unit 2	March 1980	Refueling Outage
Unit 3	December 1980	Refueling Outage

The inspector verified completion of this modification and had no questions or comments.

b. NSM 819C Fire Hose Stations inside U-3 RB

Amendment 61 to Unit 3 Operating License DPR-55, required a number of fire protection modifications. Various completion dates were specified in the amendment. One of these items pertained to hose stations within the reactor building.

The inspector reviewed this item and found six fire hose stations installed within the Unit 3 reactor building. The work was required to be completed prior to startup for cycle 6 operation. The valves for these hose stations have been included in OP/3/A1104/1C, Low Pressure Service Water.

The inspector verified completion of this modification and a future inspection will verify compliance with fire codes.

9. Emergency Power Testing

On Friday, January 30, 1981, Emergency Power Switching Logic (EPSL) Standby Breaker Closure Periodic Test Procedure, PT/3/A/610/1H, was being performed on Unit 3. In the process of returning breakers 3B2T-5 and 3B1T-2 to normal, following completion of the test, an inadvertent load shed and Keowee Emergency actuation was initiated. It was discovered that six sets of links were left open contrary to steps in the procedure which require their closure. Review of the completed procedure revealed that the steps requiring the closure of the links had been double verified, though the links remained open.

The purpose of PT/3/A/610/1H, EPSL Standby Breaker Closure Test, is to verify that the circuitry utilized to transfer the unit auxiliaries from the startup source to the standby bus operate properly. Proper operation is verified by observing statalarms, computer points, and measuring the actual times of several time delay relays. The initial preparation for the test involves placing jumpers and lifting links to allow the undervoltage transfer circuitry to perform its designed function without initiating an actual loadshed and Keowee Emergency Start. Additionally, fuses are removed and installed per the procedure on the standby bus feeder breakers as required to prevent their tripping during the test. Auxiliaries were being supplied through transformer CT-3 at the start of the test.

The cause of this particular incident was due to two separate errors. After the test acceptance criteria had been met and equipment was being returned to normal, a Performance Technician read the steps while the I&E technicians performed the work. After step 12.63 was complete, the Performance Technician read step 12.64. Both I&E technicians interpreted the step to require only the removal of the variac. They did not close the sliding links that are also required by the step. One of the technicians signed the step as being complete and the performance technician performed the required double verification. He assumed that as the I&E Technician removed the variac leads and tightened the link screws, that he was also closing the sliding links. The links were, in fact, left open for the remainder of the test. Steps 12.65 through 12.68 were subsequently completed successfully.

The Performance Technician and an operator went to the breaker blockhouse to complete the last two steps of the procedure. Step 12.69 specified the closure of breaker 3B2T-5, which is accomplished locally at the breaker. Several unsuccessful attempts were made to close this breaker. Further attempts were then made using the remote switch located in the Unit 3 Control Room. At this point, the second error was committed. The Performance Technician instructed the operator to reinsert the control fuses into breaker 3B1T-1 as required by Step 12.70. (An investigation into the failure of breaker 3B2T-5 to close in properly was not conducted prior to taking this action.) As an attempt was made to reinsert the fuses, breaker 3B1T-1 immediately tripped causing a load shed and Keowee Emergency Start. Power for unit auxiliaries was then being supplied through Transformer CT-4 by both Keowee units.

Two Performance Technicians began investigating the cause of the load shed and Keowee Emergency Start. A Shift Technical Advisor (STA) and Performance Technician noticed that Statalarm 3SA15-14, volt monitor logic undervoltage, was still lit indicating a low voltage on the startup source. This alarm was recieved several times during the test. Performance Technicians then went into the cable room to verify proper closure of the links specified in Steps 12.63 and 12.64. At this point is was discovered that the six links listed in Step 12.64 had not been closed. Once the links were closed Statalarm 3SA15-14 cleared, indicating the low voltage condition had been rectified. Breaker 3B2T-5 was successfully closed and the fuses were reinstalled in breaker 3B1T-1. The power for the unit auxiliaries was then transferred from CT-5 to CT-3, which is the normal shutdown supply.

Technical Specification 6.4.1 requires that the station be operated and maintained in accordance with current written approved procedures.

The Incident detailed herein depicts two failures with the requirement to follow procedures. This is a violation and applies to Unit 3 (287/81-04-03).

10. Overpressurization of Seconda Side of Steam Generator - Unit 3

Technical Specification 3.1.2.4 allows a maximum pressure of 237 psig on the secondary side of a steam generator whenever the vessel shell is below 110°F. This limitation provides protection against nonductile failure of the secondary side of the steam generator.

During shift turnover, on February 26, the on coming crew observed a pressure of 500 psig on B steam generator, while the vessel temperature was at 70°F. Corrective actions were initiated immediately and the pressure was reduced to with the TS limit within 3 minutes.

At the time of the event, the plant was preparing for startup following an extended refueling outage. Earlier in the day, at 3:20 p.m. the secondary system was changed from condensate recirculation to feedwater recirculation. The condensate and feedwater valve checklist was completed per procedure. This procedure calls for the startup control valve block valve to be open. It is suspected that the startup control valves leaked allowing the steam generator to overfill and overpressurize the system.

The steam generator was in a wet layup condition at the time the change was made to feedwater recirculation. In wet lay up, the steam generator high level alarm is actuated, thereby removing this audible trouble indicator from the operator. The main steam pressure indicator does not have an audible annunciator at this pressure range.

A technical analysis of the overfill event on the steam generator and the main steam header has been performed by the licensee's Mechanical and Nuclear Division. A visual survey of hangers on the system from the stop valves to the steam generator has been conducted. No damage was reported. Hanger spring settings are within specification.

Exceeding the technical specification pressure temperature limitation is a violation of TS 3.1.2.4 and applies to Unit 3 (287/81-04-01).

11. Reactor Trips - Safety System Challenges

The inspector reviewed data from recent reactor trips and safety system challenges to ascertain plant response, availability of data regarding the events and compliance with regulations, technical specifications and license conditions.

The events reviewed are discussed below.

a. On 2/11/81, at 9:23 p.m. Oconee 2 tripped from 45% Full Power (F.P.). The unit had been running on two RCP's (reactor coolant pumps) and was attempting to start a third RCP when the reactor trip occurred. Starting the third pump apparently decreased voltage to one of the two operating RCP's and a RCP/flux trip was initiated. On 2/12/81, at 0:33 a.m. during the trip recovery, Oconee 2 tripped from 4% F.P. The reactor tripped on high RCS pressure which resulted from increasing reactor power at too high a rate for this low power level. Details of these two events follow:

   On 2/11/81, Oconee 2 had been operating for approximately nine days on three RCP pumps at 73% F.P. High bearing temperatures caused by a low oil level had required taking 2B1 RCP out of service.

   While performing PT/0/A/150/19 (Electrical Penetration Leakage Test), a leak was discovered within the 2A1 RCP electrical penetration. An investigation of this leak was required to verify building integrity and 2A1 RCP was taken out of service to allow safe inspection and testing of this penetration. The RCP/flux reactor trip occurred when 2A1 RCP was restarted. The alarm typer indicates that the trip occurred immediately after restarting the pump. The RCP/flux trip is initiated by a RCP power monitor. The power monitor is a watt transducer which monitors current and voltage being used by the RCP. It outputs a voltage signal which is proportional to power drawn by the RCP. The output signal is fed to a pump monitor logic module which can initiate a trip signal to all four RPS (Reactor Protective System) channels if RCP power drops by 25% for more than 200 ms.

   This logic circuitry will generate a RPS trip signal if any of the following conditions exist:

   (1) one RCP per loop at 54% F.P. or greater,

   (2) zero RCP's in one loop, or

   (3) one RCP at greater than 0% F.P.

   At the time of the trip, switchyard voltage was low due to system demand. The lowered switchyard voltage apparently contributed to a voltage drop in the power supplied to RCP 2B2 when 2A1 was restarted. This power drop was sufficient in magnitude and duration to initiate the 2B2 power monitor RCP/flux trip signal.

   No major problems resulted from the trip, thus a trip recovery ensued. After reaching criticality, a control room trainee was withdrawing control rods manually to begin power escalation. He pulled rods at about one DPM (decade per minute) on the intermediate range. He stopped at 10^{-8} amps and recorded critical data per the reactor start up procedure. When he started withdrawing rods again, he continued with a withdrawal rate of about one DPM (two decades on the intermediate range represents 0% to 100% F.P.). When the point of sensible heat was reached, the rate of heat increase and resultant swell was too fast for the pressurizer to correct and the reactor tripped on high RCS pressure. The heatup rate did not exceed TS limit and the maximum RCS pressure during the transient was 2294 psig.

In both trip indicents, the Reactor Protection System properly tripped the reactor upon detection of the applicable signals mentioned previously and support systems appeared to function properly. The inspector will follow the licensee's ongoing in-station analysis of the two reactor trips.

b. Oconee Unit 1 tripped from 85% full power on February 2, 1981, at 2:55 p.m. The initiating event was a turbine trip caused by loss of excitation to the generator field. At the time of the trip, control operators were adjusting the Volt Amperes Reactive (VAR) on Unit 1 generator. Subsequent investigation discovered a faulty potentiometer in the voltage adjustment regulating control switch. This caused the VAR's to decrease to the point where the generator excitation was lost.

The reactor trip was an anticipatory trip due to the turbine trip. The unit response was normal, requiring no manual or unusual operator action to recover.

Item (7) of 10 CFR 50.72(a) requires that events of this type be reported to the NRC Operations Center as soon as possible and in all cases within one hour of the occurrence. A review of the record revealed that the licensee did not report the event to the NRC Operations Center as required. The resident inspector and Region II personnel were aware of the event.

The failure to report the event within the hour to the NRC Operations Center is considered to be a violation of 10 CFR 50.72(a)(7) and applies to Unit 1 (269/81-04-01).

12. Loss of System Status on Unit 1

At 1:30 p.m. on February 24, a rapid decrease in pressurizer level was noted when the "B" LPI pump was started to initiate decay heat removal. The pump was immediately secured. The unit was in a shutdown condition and a cooldown for maintenance work on the RCS was in progress. Subsequent investigation revealed that LP-42, LPI recirculation isolation valve to the Borated Water Storage Tank (BWST), a normally shut valve, was open. This caused flow from the discharge of the "B" LPI pump to be diverted from the RCS to the BWST thus decreasing the pressurizer level. It was later discovered that the Control Room Operator on the previous shift had requested auxiliary operators to open LP-42 when he intended to have HP-42 opened to increase letdown from the primary. HP-42 was then opened and LP-42 shut and a normal cooldown commenced. All of the primary coolant diverted from the RCS was accounted for.

Inspectors reviewed procedures OP/1/A/1102/10, Controlling Procedure for Unit Shutdown, OP/1/A/1104/02, LPI System and Operation and OP/1/A/1104/04, HPI System Operation and determined that the process of increasing RCS letdown flow by bypassing the letdown orifice by opening HP-42 or LP-42 was not addressed in these procedures.

Removal and Restoration of Station Equipment, Procedure OP/0/A/1102/06, provides the methods used to remove from service or change from procedure designated status station equipment not covered by other operating procedures.

Inspectors found no evidence that a Removal and Restoration Procedure had been initiated for either valve on February 23. This is a failure to follow procedure OP/0/A/1102/06 and constitutes a violation of Station Technical Specification 6.1.4a that resulted in a loss of system status as required by 10 CFR 50 appendix B Criteria XIV, Inspection, Tests and Operating Status.

This is a violation and applies to Unit 1 (269/81-04-02).

13. Radiological Survey

The inspector, on a continual basis, conducts radiation surveys of selected portions of the auxiliary and turbine buildings. The results of two such surveys are detailed below.

a. On February 9, 1981, at approximately 2:30 p.m. while performing a routine plant tour and radiation survey, the inspector detected that a janitor's sink located in the Auxiliary Building Room 357 was contaminated to the point of reading approximately 20 mr/hr on contact. The sink nor the room were posted as being contaminated. The inspector immediately notified a Health Physics representative who subsequently took corrective action.

   10 CFR 20.201 requires that radiological surveys be performed as necessary for the licensee to comply with regulatory requirements. 10 CFR 20.203 further requires each radiation area be conspicuously posted and that any additional applicable information appropriate in aiding individuals in minimizing exposure to radiation or radioactive materials be provided.

   Contrary to the requirements of 10 CFR 20.201 the licensee did not adequately survey the auxiliary building, room 357, in order to properly post the area for the purpose of personnel safety pursuant to 10 CFR 20.203. This is a violation and applies to Unit 3 (287/81-04-02).

b. On or about February 6, 1981, during a routine plant tour and radiation survey, the inspector detected five sealed wooden boxes containing radioactive waste, which were reading between 3 and 10 mr on contact. The boxes were neither labeled or roped off.

Licensee procedure HP/0/B/1000/09, Procedure for Removal of Items From RCZ's or RCA's, requires in part that the items be surveyed and appropriately tagged or labeled.

Contrary to the reuqirements of the applicable procedure and Technical Specification 6.4 which requires the use of such procedure, the five wooden containers were not labeled or tagged.

This is a violation and applies to Unit 1 (269/81-04-03).

In our letter of January 20, 1981, which transmitted Inspection Report 50-269/80-31, 50-270/80-27 and 50-287/80-24, a violation of similar nature was identified in Appendix B, item B.

14. Primary Containment Integrated Leak Rate Test

The inspector reviewed surveillance activities to determine that the primary containment integrated leak rate test (ILRT) was performed in accordance with appropraite sections of Technical Specification 4.4; PT/0/A/150/3, Reactor Building Integrated Leak Rate Test Procedure; Appendix J to 10 CFR 50, and ANSI N45.4. The inspection was a coordinated effort involving Resident Inspectors and Region II specialists. Selected sampling of the licensee's activities which were inspected included (1) review of PT/0/A/150/3 to verify that the procedure was approved and conformed to Technical Specifications; (2) observation of test performance to determine that test prerequisites were completed, special equipment installed and calibrated, appropriate data were recorded and analyzed; and (3) preliminary evaluation of leakage rate test results to verify that leak rate limits were met. Pertinent aspects of the test are discussed in the following paragraphs.

a. General Observations

The inspectors witnessed or reviewed portions of the test preparation, containment pressurization, temperature stabilization and data processing in the period February 13-18, 1981. The following items were inspected:

(1) The test was conducted in accordance with an approved procedure maintained at the test control center. Changes to the procedure were documented and approved as required.

(2) Selected test prerequisites were verified.

(3) Plant systems required to maintain test control were in operation.

(4) Calibration and use of special instrumentation was verified.

(5) Venting and draining of specific systems were verified.

(6) Data required for performance of the ILRT calculations were recorded at 5 minute intervals.

(7) Problems encountered during the test were described in the test event log.

(8) Pressurized gas sources were veiwed for proper isolation and venting to preclude in-leakage or interference of out-leakage through containment isolation valves.

b. System Venting and Draining

During the review of the revised test procedure PT/0/A/150/3, the inspector found that the instructions included action step sign-offs or double verification of each system drained. The problems with pipe cap removal on vent and drain lines (see IE Rpt. 50-269/80-06, 50-270/80-16) were adequately addressed by the incorporation of sign-offs to verify each cap removed. The inspector verified the adequacy of selected system line-ups by use of system diagrams followed by a visual inspection of valve positions and tags on system inside the Reactor Building. Of the fifteen penetration line-ups inspected, all line-up and vent caps were as specified.

c. Testing Problems

A brief chronology of significant events and problems encountered during the course of testing are listed and discussed below:

2/14/81	2130	Containment pressurization commenced.
2/15/81	2200	Building pressure 31 psig, the stabilization period commenced.
2/16/81	0245	Run for the ILRT calculations commenced.
2/16/81	1330	ILRT terminated. Ltm=0.1085 WT%/day
2/16/81	1600	Supplemental verification test with imposed leak rate of 7.107 SCFM commenced.
2/16/81	2300	Supplemental test complete. The verification leak rate was 0.2258 WT%/day. The lowest acceptable value is 0.2405 WT%/day. Results were unsatisfactory.
2/16/81	2325	The second verification test was started using

		a differenct flow instrument for the imposed leak.
2/17/81	1120	Second verification secured. Leakage did not fall into the acceptance limits of the ILRT. It was suspected actual building leakage had decreased. A second ILRT data run was commenced.
2/17/81	1300	NRC Region II was informed of the testing problems.
2/17/81	2300	The second 10 hour ILRT data run was terminated. Ltm=0.0625 WT%/day. Comparison of the LTM for the two ILRT indicated a significant change in leakage therefore a third verification test was performed to dispel doubts as to the adequacy of test instrumentation.
2/18/81	0020	The 5 hour verification test commenced.
2/18/81	0520	The verification test was terminated. The results were considered satisfactory by the licensee.
2/18/81	2030	The Reactor Building was depressurized and inspected.

The second ILRT was required as a result of a large decrease in the building leakage rate that invalidated the subsequent verification test. This was attributed the seating of the large butterfly type valves in the Reactor Building Purge System and an insufficient stablization period at the test pressure.

The flow meters used to measure the rate of the imposed leak for the verification test became suspect when the results of the test were unsatisfactory. When the turbine vane flowmeter (SR#1051C) and a rotometer instrument (SR#7004-39848) were both connected to the same flow source a conflict in measured output resulted. The rotometer indicated a rate of 1SCFM lower than the turbine flowmeter for the 7SCFM source. The licensee opted to use the rotometer for further testing based on the dependability of that instrument and substantiate that decision by having both flow instruments calibrated.

Final analysis of the leak rate data, utilizing the results of the calibration data of the flowmeters used in verification testing, will be performed by the licensee and will be reported in the test report to the Office of Nuclear Reactor Regulation (NRR). The inspectors preliminary review indicated that the calculated leakage rate was less than the 0.75 LT allowable.

Of the areas inspected, no violations were noted.

15. IEB 80-23 - Valcor Solenoids

The corrective actions required by IEB 80-23 as addressed in NRC inspection report 50-269/80-38, 50-270/80-35 and 50-287/80-32 for deficiencies in Valcor solenoids in the Emergency Feedwater System was completed February 27, for Units 1, 2 and 3. Inspectors verified by direct observation that the subject fuses that would prevent a failed solenoid from tripping the entire bus are installed. Inspector review of the instrument modification package NSM 1710 revealed that the fuses were schematically located as per negotiations completed on December 5, 1980, with the licensee and IE:HQ. Operators continue to verify daily the continuity of power to the control solenoids from the control room. Licensee long term plans specify replacement of Valcor solenoids with another design that would meet current environmental qualifications.

This completes the corrective actions required by this bulletin.

16. Licensee Corrective Actions

Reactor Building Spray (RBS) Pump Impeller Locking Devices

The licensee has performed the corrective repairs to the Unit 1 RBS Pumps specified in letter report to the NRC dated January 29, 1981. The condition of loose impeller locking devices was previously addressed in IEC 79-19 and IE Inspection Report 50-287/80-02. The licensee and the pump vendor completed design details of the improved locking assembly and the licensee installed the modified device on the Unit 3 RBS Pumps during the current refueling outage.

Unit 1 RBS pumps were inspected during an outage begun on February 8, for OTSG tube repairs. Inspection revealed that the 1A RMP Pump locking device required less than the specified torque to loosen the capscrew for removal although it was not found loose. The 1B Pump was found satisfactory. The deficient locking devices were modified at that time.

As documented in the letter report, the Unit 2 RBS Pumps will be inspected on the next outage of greater than two weeks.

Reactor Building Electrical Penetration Degradation

Additional surveillance requirements and penetration pressurization specified as corrective action in RO-270/81-02 for a degraded Unit 2 electrical penetration has been verified through direct observation by Resident Inspectors.

Corrective action is the result of the February 11, discovery that penetration EMV-2 failed to hold the 60 psig overpressure of SF6 gas used as a dielectric. Inspectors witnessed licensee leak testing of the subject penetration to determine which or both of the possible barriers had failed.

The test indicated that the Reactor Building side of the penetration leaked and the outer barrier was intact - no sign of leakage from the soap bubble test performed.

The licensee has initiated a program of purging the penetration daily to prevent arcing and monitoring radiation levels in the proximity of the penetration to alert shift personnel of possible out leakage from the Reactor Building. Inspectors have verified these measures by review of logs of daily inspections and presence of operating radiation monitoring equipment at the penetration.

Repair of the interior bushing was not possible due to activity levels inside the containment during reactor operation. The licensee performed a safety evaluation as required by 10 CFR 50.59 and determined that operation with only a single containment barrier was not an unreviewed safety question. Inspectors will continue to periodically monitor the penetration until it is repaired or replaced during the next available outage.

17. Steam Generator Tube Plugging

On December 26, 1980, reactor coolant sample results on Oconee Unit 1 indicated an apparent tube leak of approximately 0.12 gpm. A combination of power reductions and continual leak calculations allowed power operation to continue through February 6, 1981, when the unit was shut down to repair the tube leak.

Historically at Oconee, failed steam generator tubes have been located by filling the steam generator shell above the upper tube sheet, pressurizing the shell, and searching for water leaking from the failed tubes through the primary side lower manway. Failed tubes may also be located by pressurizing the drained shell, with a gas, filling the primary side of the generator to approximately two inches above the upper tube sheet, and searching for bubbles coming from the failed tubes with a TV camera. This second technique was originally employed by Babcock and Wilcox and the Crystal River Plant but has subsequently proven effective on small leaks both at Arkansas Nuclear One and during this outage at Oconee.

The failed steam generator tube, 78-2 in generator A, was easily located and subsequently plugged. Due to the tube's location, one row away from the lane, it was also stabilized.

Steam generator tube stabilization is a process in which a rod is affixed inside the failed tube to prevent the tube from being expelled from the generator in the event of a double ended circumferential shear of a section of the tube.

The administrative and technical mechanics of the tube plugging effort were monitored throughout the evolution with no areas of concern.

18. RB Sump Level Instrumentation - Units 1, 2 and 3

Water leakage inside the reactor building is collected in the normal sump and the emergency sump. The RB normal sump has a range of 0 to 30 inches, with a Statalarm at 15 inches and a computer alarm at 22 inches. Level is indicated and recorded in the control room and is recorded by the plant computer every five minutes.

The emergency sump has a range of 0 to 10 feet with a computer alarm at 4 feet.

The surveillance procedures for these instruments and the data from the most recent calibrations and tests were reviewed. The procedures were satisfactory for calibration and functional testing and the data and test results met the acceptance criteria.

Technical Specification 4.1.1 requires calibration of the emergency sump at a refueling frequency. The normal sump instrumentation is not included in the Technical Specification, but is also done on a refueling frequency.

The test procedures and dates last performed are as follows

	DATE		
Procedure	Unit 1	Unit 2	Unit 3
IP/0/A/203/IE	7/4/80	11/12/80	12/19/80
IP/0/B/233/3	7/8/80	11/12/80	12/19/80

IP/0/A/203/1E RB Emergency Sump Level Instrument Calib.ation
IP/0/B/233/3 RB Normal Sump Level Instrument Calibration

Within the areas inspected, no violations were found.

19. Reactor Building Air Temperature

On September 5, 1980, Unit 3 was shutdown to repair a Reactor Protection System (RPS) pressure transmitter. An attempt to repair the RPS pressure transmitter during reactor operation could not be completed due to an ambient temperature of 130°F in the reactor building where the transmitter is located.

Questions were raised concerning the operative temperature limit for the RPS transmitters and the ramifications of an elevated containment temperature on containment pressure following a LOCA.

A review of vendor supplied equipment specifications on the RPS transmitters reveals an operative temperature bandwidth of -20°F to 160°F which effectively alleviates immediate concern over equipment environmental qualification.

Moreover, Inspection and Enforcement Bulletin IEB-79-01B, September 30, 1980 and Order For Modification of Licenses Concerning Environmental Qualification of Safety-Related Electrical Equipment, October 24, 1980, further address the area of concern.

The licensee performed a computer analysis to determine the effect reactor building air temperature has on post LOCA building pressure. Examinations of the analyses reveals that the original containment pressure analysis for the design basis LOCA event assumed a nominal value of 110°F for the initial RB temperature and is reported in FSAR Section 14.2.2.3.5. The analysis was subsequently revised and reported in FSAR Supplement 13. Current analysis indicates the peak accident pressure appears not to be significantly influenced by initial RB air temperature. Any small sensitivity appears conservative with respect to the maximum RB pressure when the actual temperature is higher than the assumed temperature. This behavior is apparently due to the fact that the higher initial temperature dictates a lower mass of containment air and hence results in a slightly lower peak accident pressure.

Based on the above analysis and ongoing station modifications designed to lower reactor building operating temperatures, immediate concerns are alleviated.