UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEOF 3IA 30323

Report Nos. 50-325/87-39 and 50-324/87-40

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket Nos. 50-325 and 50-324 License Nos. DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: November 1 - 30, 1987

Inspectors: for S. Vias 12/24/87
W. H. Ruland Date Signed

for S. Vias 12/24/87
L. W. Garner Date Signed

Approved By: for S. Vias 12/24/87
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine safety inspection involved the areas of maintenance observation, surveillance observation, operational safety verification, Compliance Bulletin 87-02, Unit 2 Reactor Building tour with auxiliary operator, followup on inspector identified Unresolved Item, and setpoints for HPCI and RCIC high steamline flow.

Results: One violation was identified - Failure to Calibrate Jet Pump Instrument in Accordance with Procedure.

REPORT DETAILS

1. Licensee Employees Contacted

   P. Howe, Vice President - Brunswick Nuclear Project
   C. Dietz, General Manager - Brunswick Nuclear Project
   T. Wyllie, Manager - Engineering and Construction
   J. Holder, Manager - Outages
   R. E[illegible]tein, Manager - Technical Support
   E. Bishop, Manager - Operations
   L. Jones, Director - Quality Assurance (QA)/Quality Control (QC)
   R. Helme, Director - Onsite Nuclear Safety - BSEP
   J. O'Sullivan, Manager - Maintenance
   G. Cheatham, Manager - Environmental & Radiation Control
   J. Smith, Manager - Administrative Support
   K. Enzor, Director - Regulatory Compliance
   A. Hegler, Superintendent - Operations
   W. Hogle, Engineering Supervisor
   B. Wilson, Engineering Supervisor
   B. Parks, Engineering Supervisor
   R. Creech, I&C/Electrical Maintenance Supervisor (Unit 2)
   R. Warden, I&C/Electrical Maintenance Supervisor (Unit 1)
   W. Dorman, Supervisor - QA
   W. Hatcher, Supervisor - Security
   R. Kitchen, Mechanical Maintenance Supervisor (Unit 2)
   R. Poulk, Senior NRC Regulatory Specialist
   D. Novotny, Senior Regulatory Specialist

   Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, office personnel, and security force members.

2. Exit Interview (30703)

   The inspection scope and findings were summarized on December 3, 1987, with the general manager. The violation was discussed in detail (see paragraph four.) Two Unresolved Items were identified during this inspection and are discussed in paragraphs six and eight. The licensee acknowledged the findings without exception. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during the inspection.

3. Followup on Previous Enforcement Matters (92702)

   Not inspected.

4. Maintenance Observation (62703)

The inspectors observed maintenance activities and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance.

The inspectors observed/reviewed portions of the following maintenance activities:

87-BTWF1	Repair of Diesel Generator (DG) Starting Circuit.
MI-03-2B1-6	B21-PDI-R608 A-W General Electric (GE) Model 180 Panel Meter.
MI-03-12I	DG Time Delay Relays RCR, RTR, SC, STR, SSTR, JATR.
OP-08	Control Rod Drive Hydraulic System: Section 8.9 Charging Hydraulic Control Unit Accumulators.

On November 12, 1987, during performance of Maintenance Instruction MI-03-2B1-6 per work request 87-BFBT1, the inspector observed the Instrumentation and Control (I&C) technician performing adjustment of a Unit 2 jet pump differential pressure indicator in a manner different than that required by the procedure. Section D requires the instrument to be calibrated by inputing a milliamp signal equivalent to 50% of scale and adjusting the mechanical zero to obtain a 50% output reading. The technician used the milliamp current equivalent to 0% and adjusted the meter to 0% output reading. This was the manner in which the indicator had been calibrated prior to November 1985. On November 1, 1985, the current revision, Revision 2, had been issued to calibrate at 50% rather than 0% in keeping with good industry practice and ANSI standard B40.1. This error was brought to the attention of the technician's supervisor. The supervisor later informed the inspector that a total of six instruments had been done this way. These instruments were redone in accordance with the procedure. At no time were the instruments returned to service out of adjustment. These instruments are used to perform Technical Specification (TS) surveillance 4.4.1.2. Failure to perform the calibration in accordance with MI-03-2B1-6 is a violation of TS 6.8.1.a, which requires procedures recommended in Regulatory Guide 1.33 be implemented: Failure to Calibrate Jet Pump Instrument in Accordance with Procedure (50-324/87-40-01).

On November 20, 1987, the inspector observed the output breaker of DG No. 4 failed to close during post maintenance testing. Failure to close was attributed to operating personnel not fully racking the breaker into the full in position upon return to service. During maintenance on the DG, the breaker had been racked out. During troubleshooting, operating and engineering personnel examined the breaker compartment and visually discovered no problem. The indicator light on the breaker compartment was lit indicating that control power was available and the breaker was open. Upon racking the 4160 KV breaker in approximately 2 additional turns, the breaker could be closed successfully to complete the post maintenance testing. The inspector will continue to review this event.

The inspector found that temporary rigging and scaffolding erected in Unit 2 for pre-outage work did not adversely affect equipment operability. WP-18, Temporary Rigging and Scaffolding, Revision 1, Deviation 1, provides guidelines for the protection of plant equipment during installation and use of rigging and scaffolding. The inspector reviewed WP-18 and toured Unit 2 reactor building, with a construction foreman and the cognizant engineer, to verify that no safety-related equipment would be adversely affected by the scaffolding. The licensee had taken precautions, for all scaffolding examined, to prevent scaffolding from any substantial movement during a seismic event. The inspector noted only one problem: a wooden scaffold above the Unit 2 twenty four volt batteries had been attached to the battery racks with wire at all four legs. The wire had been initially attached as a temporary measure to support the scaffold legs during assembly. The attachments should have been removed once the scaffold was complete. The licensee removed the wire. The inspector has no further questions in the area at this time.

One violation and no deviations were identified.

5. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

1MST-RCIC22M Reactor Core Isolation Cooling (RCIC) Steamline Low Pressure Instrument Channel Calibration.

OI-3.3 Auxiliary Operator Daily Surveillance Report.

OI-3.4 Daily Check Sheets.

PT-12.2D No. 4 DG Monthly Load Test.

Inspection of Operating Instructions OI-3.3 and OI-3.4 was accomplished by accompanying operators during the performance of their rounds in Unit 1 and 2 reactor buildings during backshift hours.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

The inspectors verified conformance with regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the technical specifications were met. Control room, shift supervisor, clearance and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specifications Limiting Conditions for Operations. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety to verify operability and that parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that continuity of system status was maintained. The inspectors verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature (ESF) train was verified by insuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker, including control room fuses, were aligned for components that must activate upon initiation signal; removal of power from those ESF motor-operated valves, so identified by Technical Specifications, was completed; there was no leakage of major components; there was proper lubrication and cooling water available; and a condition did not exist which might prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspectors verified that the licensee's health physics policies/procedures were followed. This included a review of area surveys, radiation work permits, posting, and instrument calibration.

The inspectors verified that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the protected area (PA); vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; and effective compensatory measures were employed when required.

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked a clearance, and verified the operability of onsite and offsite emergency power sources.

During the report period, the inspector questioned the licensee's implementation of TS 3.6.1.1 and 3.6.3, regarding de-activating valves. The main primary containment isolation valves listed in table 3.6.3-1, if inoperable, must have the associated penetration line isolated within eight hours by use of at least one deactivated automatic valve secured in the isolation position or isolate the line with a closed manual valve or blind flange. The licensee, due to no open indication available on the 1-B32-F019, reactor water sample line isolation valve, declared it inoperable and placed a clearance on the switch for redundant valve, 1-B32-F020, to prevent operator action. The licensee considered this action sufficient for deactivation. The inspector stated that the licensee's interpretation was inconsistent with the words in the TS. Also, the inspector noted that the licensee placed a clearance on the switch for valve 2-RXS-SV-4189, gas sample return to suppression pool outboard isolation valve, due to indication problems with the inboard valve. TS 3.6.1.1 requires primary containment integrity to be maintained. Primary containment integrity, as defined by TS, exists when, among other requirements:

> All penetrations required to be closed during accident conditions are either:
>
> 1) Capable of being closed by an OPERABLE containment automatic isolation valve system, or
>
> 2) Closed by at least one manual valve, blind flange, or deactivated automatic valve secured in its closed position, except as provided in Table 3.6.3-1 of Specification 3.6.3.1.

SV-4189 was "deactivated" administratively using a clearance tag.

Both valves above received no automatic open signal but do receive automatic group 6 isolation signals in the event of a Loss of Coolant Accident (LOCA) or a reactor building ventilation exhaust high radiation signal.

The inspector concluded that the licensee's current interpretation does not pose a significant risk of compromising primary containment integrity. However, the specific question whether actual physical deactivation (opening a breaker, lifting leads, etc.) is required instead of administrative deactivation still needs to be addressed by Region II/NRR. This is an Unresolved Item: Deactivation of Primary Containment Isolation System (PCIS) Valves (325/87-39-04 and 324/87-40-04).

No violations or deviations were identified.

7. Compliance Bulletin 87-02 (25016)

In accordance with Temporary Instruction (TI) 2500/16, the inspector reviewed the selection of fasteners to be tested. The selection involved choosing fasteners of the types and grades listed in the bulletin which had been utilized on site in safety-related and non safety-related systems during the past 12 months as determined by transaction records of plant stores. The inspector accompanied plant personnel while the selected fasteners were obtained, bulletin data sheets were completed, and samples were labeled. In addition, storage locations in plant stores, plant warehouse, and construction warehouse were sampled to verify that the chosen sample is representative of fasteners recently installed or planned to be installed in the plant. In particular, storage locations were reviewed for fasteners of types and grades not selected but listed in the bulletin and/or fasteners with markings from the following list: KF, KS, J, M, FM, NF, RT, H, A and MS. During this process, an additional five items were selected to be tested.

No violations or deviations were identified.

8. Unit 2 Reactor Building Tour with Auxiliary Operator (71707)

On November 12, 1987, the inspector accompanied a fully qualified Auxiliary Operator (AO) on a tour of the Unit 2 Reactor Building during a backshift. The inspector noted the following discrepancies:

o A clearance tag was not hung on a 120 V breaker and was not clearly identified as to which breaker was tagged. Clearance 2-1704, Tag 2, for 2-B32-F043B, was taped to the inside door of a 120 V distribution panel 2-HN9 on Motor Control Center (MCC) 2XB. The tag was for the B32-F043B motor heater breaker in the off position. No breaker was labeled as such. The AO did not question the tag placement until the issue was raised by the inspector. Administrative Instruction AI-58, Clearance and Equipment Tagging, Revision 21, section 4.1.2.5, states, "When placing the tag, the following requirements should be observed. Clearance tags should be placed as close as possible to the affected equipment."

Based on the two "shoulds" above, no clear procedure requirement exists on clearance tag placement. Further, section 4.1.3 of AI-58 states that, "No tags will be attached unless the valve or breaker is properly labeled. Variations in noun name descriptions may occur between labels on components/panels and procedures." The breaker for the motor heater had no label or noun description next to it or in the panel. A sheet inside the panel did indicate MCC compartment numbers associated with each breaker. No other breaker in that panel had labels. The particular breaker in question had supplied power to the motor heater for a valve motor that was no longer installed in the plant. The licensee agreed to resolve the breaker labeling questions in AI-58.

The two above clearance issues are considered an Inspector Followup Item: Revise OI-1 and AI-58 to Address Concerns Found During AO Tour (325/87-39-02 and 324/87-40-02).

- The AO removed a clearance tag on a Residual Heat Removal (RHR) room cooler by recording the valve numbers on the back of his yellow gloves. He read the clearance then wrote the 3 valve numbers in a column on his yellow glove (2-RIA-IV-129, 2-RIA-IV-229, and 2-SW-V-124). He then laid the clearance sheet aside, using the writing on his glove as the basis for clearance removal and valve restoration. This practice removes the reviewed clearance sheet from the operator, and increases the chance for errors. No current procedure prohibits this practice at Brunswick. The licensee agreed in the exit to modify Operating Instruction OI-1 to specifically prohibit this practice. Training will be held on this item by the licensee during future real time training sessions.

- At approximately 9:15 p.m., the AO left a posted and locked high radiation area door unlocked with the inspector observing. The inspector stood by the door and no unauthorized entry was made by anyone else. The door had been unlocked for about 5 minutes.

  The chain link door prevented access to the Unit 2 80 foot East Fuel Pool Heat Exchanger area. Review of radiation surveys taken on November 8 and 14 showed that a hot spot of 5 REM/hour contact reading existed at a pipe elbow in the area. General area maximum readings were 600 to 700 mrem/hour. The two technicians who performed the surveys stated that a reading 18 inches from the hot spot was not taken in determining the general area reading.

  Based on the definition of a high radiation area contained in 10 CFR 20.202(b)(3) and the locking requirement in TS 6.12.2, an area is a "high radiation area" required to be locked to prevent unauthorized entry with Operations Shift Foreman administrative control of the keys, if the "area, accessible to personnel, in which there exists radiation originating in whole or in part within licensed material at such levels that a major portion of the body could receive in any one hour a dose in excess of 1000 millirem."

Based on the above surveys and inspector observation of the area, a major portion of a body could not have been subject to 1000 mrem in any hour since the area was inaccessible to a major portion of a body.

o Routine full dress out requirements for wearing of a hood was ignored by the AO. Entry into the 80 foot Fuel Pool Heat Exchanger area and the mini-steam tunnel was with a hard hat instead of a hood, did not include taping, and failed to place the dosimetry in the protective clothing pocket as taught in General Employee Training. In addition, the entry into the mini-steam tunnel was preceded by a phone call to the duty Health Physics (HP) technician who stated that full dress out requirements were necessary for entry.

The above HP issues will be inspected by Regional HP inspectors during their next routine inspection. This item remains Unresolved till then: Poor HP Practices by AO - Possible Programmatic Issues (325/87-39-03 and 324/87-40-03).

Based on disciplinary action taken by plant management, the AO no longer works at Brunswick.

No violations or deviations were identified.

9. Followup on Unresolved Item (92701)

(OPEN) Unresolved Item, 325/87-36-02 and 324/87-37-02, Additional Environmental Qualification (EQ) Items.

The licensee identified additional problems with wire and terminal blocks inside Limitorque actuators. These problems were found during the 100% inspection of EQ actuators that the licensee agreed to perform at an enforcement conference at Region II on September 17, 1987. See Inspection Report No 50-325, 324/87-22 for additional information on EQ issues at Brunswick.

The following is a summary of EQ issues reported by the licensee to the resident office this month:

Issue or Item	Valves	Status
3 Unqualified Butt Splices on Motor Leads, Unqualified Lead Repair	2-E11-F006D	Under Evaluation. Motor Replaced.
THW Jumper Phelps-Dodge	2-E41-F008	Engineering Evaluation Report (EER) Complete. Replaced Wire.

DOR Limit Switches In CAT 1 Valves	1-E11-F020B 2-CAC-V22	Replaced.
Misapplied Raychem Splice	1-E11-F008	EER In Progress (IP). Probably Qualifiable (QBL). Replaced.

This item continues to remain unresolved pending NRC action on the enforcement package.

No violations or deviations were identified.

10. Setpoints for High Pressure Coolant Injection (HPCI), RCIC High Steamline Flow (93702)

The licensee discovered a problem with the setpoint of the 2-E41-PDT-N004 instrument after the instrument indication started drifting up from its normal reading of about -20 inches. The control operator's daily surveillance procedure OI-3.2, Revision 10, listed the normal reading as -22 inches. On November 5, 1987, after operations questioned the operability of the instrument when the reading crept up to -10 inches, systems engineering declared the instrument operable in a 3 part memo to operations. In that memo, engineering stated that the -8 1/2 inches difference between low and high pressure taps on the elbow meter posed no operability concern relative to the current reading of -10 inches. The engineer proposed a new operability range for the channel check of -10 $\pm$ 10 inches instead of the old range of -22 $\pm$ 10 inches. No investigation was performed at that time on why the original normal range was inadequately specified.

On November 24, 1987, E41-PDT-N004 drifted further up to +5 inches, exceeding the operable range specified in the engineer's three part memo. Operations declared the instrument inoperable the next morning when the shift foreman reviewed the Daily Surveillance Report (DSR). Additional guidance was then provided from engineering to operations concerning the E41-N004 instrument. The licensee and inspector had reviewed the isometric drawings for this instrument and independently determined that the -8 1/2 inches difference between the taps was accurate but not the correct number for a head correction. Based on a review of drawings FS-I-7080-2, Sheets 12-8, and FS-I-7080-1, Sheet 12-6, both dated August 16, 1974, the head correction for the instrument should have been -28.75 inches, which was close to the -22 inches normal and the -30 inches previously recorded in the DSR prior to June 1987.

The licensee surmised that the instrument drift may be coming from a leaking instrument piping inside the drywell. The licensee performed the calibration of the instrument (1MST-HPCI-21M) on November 3, 1987, which showed no problems with the analog channel. The isometric also showed that a loop seal may exist in the high pressure tap tubing. The licensee reported that the isometric drawings for the other high steam flow instruments were incomplete or difficult to read. All eight instrument lines will be examined during the upcoming outages in January. The licensee has stated that the instrument (N004) is still operable since the drift has been in the positive direction (closer to a HPCI line isolation) but the drift is not so large such that the drift plus maximum spike during a HPCI start would not have the potential to trip the turbine.

The licensee found the setpoint for the N004 set incorrectly. TS 3.3.2 requires the 2-E41-N004 and N005 to be operable with a trip setpoint of 300% of rated flow. During startup testing, a trip setpoint of 219 inches was established.

The test data was used to obtain the setpoint using the following formula:

Where - $\Delta P_t = \frac{9 \Delta Pm \rho test}{\rho\ max} B$

ΔP_t = Trip Set Point

ΔPm = Measured ΔP during Vessel Inject

ρmax = Steam Density @ 1120 psig = 2.55 lb/ft^3

$\rho test$ = Steam Density during Test (945 psig) = 2.108 lb/ft^3

B = Design Factor = 1.96

The design factor (B) compensates for the increased steam flow required to inject water into the vessel at rated conditions with the turbine.

During Startup Test 15,

$$\Delta P_t = 9 \text{ (15 inches water) } \frac{(2.108)}{(2.55\ )} (1.96)$$

$$\Delta P_t = 219 \text{ inches}$$

The Pm number was obtained from the difference of the no flow (-25") to test flow (-10") reading on N004. The actual setpoint became:

Actual Setpoint $= \Delta P_t$ + No Flow Reading

$= 219 + (-25) = 194$ inches H_2O

The licensee declared operable Plant Modification 77-314, Plant Instrumentation Setpoint Changes to Comply with Standard Technical Specifications (STS), on March 20, 1978. This modification adjusted setpoints to compensate for instrument inaccuracies and drift. When this was done, the head correction for the setpoint was left off, establishing the setpoint at (219 - 12 for inaccuracies and drift) = 207 inches. A band of $\pm$ 2.25 was established. Thus, the instrument could have been set to trip $\overline{1}5.25$ inches greater than the specification in TS.

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ρmax = Steam Density @ 1120 psig = 2.55 lb/ft^3

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The above matter is unresolved, pending the licensees inspection of the instrumentation piping in the drywell. This item is identified as Unresolved Item 50-325/87-39-05 and 50-324/87-40-05, "Erroneous Setpoints, High Steam Line Instruments."

No violations or deviations were identified.