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

Report No. 50-325/92-07 and 50-324/92-07

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

Docket Nos. 50-325 and 50-324 License No. DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: March 1 - 31, 1992

Lead Inspector: for 4/24/92
R. L. Prevatte, Senior Resident Inspector Date Signed

Other Inspector: P. M. Byron, Resident Inspector

Approved By: 4/24/92
H. O. Christensen, Section Chief Date Signed
Reactor Projects Branch 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of maintenance observation, surveillance observation, operational safety verification, onsite review committee, onsite followup of events, and action on previous inspection findings.

Results:

In the areas inspected, no programmatic weaknesses, significant safety matters, violations or deviations were identified.

The licensee continues to have equipment problems which affect operation. A sluggish position relay resulted in a Unit 1 scram. Reactor Feed Pump Motor Gear Unit problems on both units and the Unit 2 primary containment hydrogen/oxygen monitor failures resulted in reduced power operation.

The slowly increasing unidentified drywell leakage in Unit 1 has placed added burdens on the operators. The inspectors identified four items which indicate inattention to detail. These problems also indicate the licensee is accepting marginal equipment conditions.

Unit 1 scrammed on February 29, 1992 from 100 percent power and restarted on March 5. Power was reduced to 60 percent for three days due to Reactor Feed Pump problems. Unit 2 operated at 77 percent power for the majority of the inspection period with a six day reduction to 60 percent to correct Reactor Feed Pump problems.

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REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *K. Ahern, Manager - Operations
   *M. Bradley, Manager - Brunswick Assessment Project
   *S. Floyd, Manager - Regulatory Compliance
   *R. Helme, Manager - Technical Support
   J. Holder, Manager - Outage Management & Modifications (OM&M)
   *B. Leonard, Manager - Training
   *P. Leslie, Supervisor - Security
   *W. Monroe, Acting Manager - Nuclear Engineering Department (Onsite)
   *D. Moore, Manager - Maintenance
   *R. Morgan, Manager - Nuclear Plant Support
   R. Poulk, Manager - License Training
   *R. Richey, Vice President - Brunswick Nuclear Project
   *C. Robertson, Manager - Environmental & Radiological Control
   J. Simon, Manager - Operations Unit 1
   J. Spencer, General Plant Manager - Brunswick Steam Electric Plant
   R. Tart, Manager - Operations Unit 2
   G. Warriner, Manager - Control and Administration

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

   *Attended the exit interview

   Acronyms and initialisms used in the report are listed in the last paragraph.

2. Maintenance Observation (62703)

   The inspectors observed maintenance activities, interviewed personnel, 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:

92-AEUF1	Troubleshoot Unit 1 HPCI Dual Valve Indication
92-AEUJ1	Unit 1 HPCI Auxiliary Oil Pump
92-AGKW1	Repair and Calibration of Unit 1 Reactor High Pressure Trip Pressure Transmitter (1-B21-PT-N023A)
92-AGMA1	Remote Shut Panel Inverter Fan Replacement
92-AGYB1	1-CAC-AT-4410 Sample Pump Removal
92-AFYX1	Reactor Feed Pump Turbine 2B Motor Gear Unit Repair

The inspector observed that procedures were used and maintenance personnel took the proper precautions. Housekeeping was adequate. There was adequate technical support when required and maintenance supervision was present for much of the work.

Violations and deviations were not identified.

3. Surveillance Observation (61726)

The inspectors observed surveillance tes ing required by Technical Specifications. Through observation, interviews, and record review, the inspectors verified that: tests confo ed 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 portions of the following test activities:

1MST-RWCU22M	RWCU Steam Leak Detection Channel Functional Test and Setpoint Adjustment
OPT-12.2A	No. 1 Diesel Generator Monthly Load Test

The inspector witnessed the performance of OPT-12.2A on March 6 and 30, 1992. The licensee tests the DG at 3500 KW for one hour every month to satisfy the requirements of Technical Specification 4.8.1.1.5. DG No. 1 met this requirement on March 6. During the March 30 test, the operators observed that the "1R" injector pum was leaking by the metering rod. The licensee stopped the test and declared DG No. 1 inoperable. The "1R" injector pump was replaced and the DG was declared operable at 2:51 a.m. on March 31, 1992. OPT-12.2A was successfully re-performed on April 2, 1992.

OPT-40.2.5	Turbine Control Valve and Extraction Steam Stop Valve Testing
OPT-40.2.9	Turbine Control Valve/Stop Valve Closure Test

The inspector observed that procedures were used and each step signed off when completed. Communications between test personnel, and between test personnel and operations was excellent. The evolutions were performed carefully and methodically.

Violations and deviations were not identified.

4. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other 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 operator, shift supervisor, clearance, STA, daily and standing instructions, 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 Specification Limiting Conditions for Operations. Direct observations of control room panels and instrumentation and recorder traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was no leakage of major components; there was proper lubrication and cooling water available; and conditions did not exist which could 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 HP policies and procedures were followed. This included observation of HP practices and a review of area surveys, radiation work mits, postings, and instrument calibration.

The inspectors verified by general observations 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 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; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate.

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

The inspector was concerned about the quality of the SCO (unit) logs and has discussed these concerns with the licensee. The log entries were incomplete, contained inconsistent entries, and lacked sufficient detail to reconstruct events. The licensee has since made a concerted effort to upgrade the quality of the logs by listing significant equipment problems at the beginning of each shift. The licensee has stated that continued improvement is still needed.

a. On February 29, 1992, with Unit 1 reactor power at 80 percent, the licensee performed surveillance test 1MST-RPS35R, "RPS Turbine Stop Valve Closure Circuit Response Time", on Turbine Stop Valve (TSV) No. 2. During this test, a half scram is created by removing a fuse in one section of the logic and then stroking the TSV to less than 95 percent open. When the half scram is received, the test button is released and the TSV re-opens. The procedure is repeated for the second sensor relay. This MST had been successfully performed on TSV Nos. 1, 3, and 4 in 1988, 1989 and 1990, respectively. The test was completed satisfactorily on the first sensor for TSV No. 2. When the control operator released the test button for the test on the second sensor, the unit scrammed. Group 2, 3 and 6 isolation signals were received. HPCI and RCIC started and RCIC injected. HPCI went to rated speed but did not inject because reactor water level increased to above the low level 2 setpoint before the HPCI injection valve could open. The control operator tripped the HPCI turbine and observed that the steam admission valve (E41-F001) did not indicate closed and the auxiliary oil pump cycled on and off.

The HPCI steam admission valve (F001) is designed to open against a differential pressure of 1300 psid and close against a differential pressure of 150 psid. The logic for the F001 valve has a position limit switch which bypasses the torque switch during the closing stroke until 4 percent open position is reached. Investigation revealed that the position limit switch was set to close slightly before the limit switch which provides the full closed indication. A review of the data revealed that the control valve (E41-V8) indicated full closed 11 seconds after the HPCI speed and discharge pressure decreased. This indicated the F001 valve closed against a differential pressure of 150 psid. Investigation revealed the valve closed but had insufficient travel to activate the full closed indication. The full closed limit switch was adjusted to operate sooner to correct this problem. ACR 92-157 was written to document the abnormal HPCI operation.

Additional investigation revealed that it took approximately 10 degrees of rotation of the HPCI auxiliary oil pump switch to shut off the auxiliary oil pump. The licensee theorized that the operator inadvertently caused the switch to rotate while tripping the HPCI turbine. The inspector observed licensee testing of the HPCI turbine which revealed that the valve position indication problem could not be replicated after the adjustment of the limit switch. However, it was demonstrated that small movements of the HPCI auxiliary oil pump switch could cause the pump to inadvertently shut off.

Investigation by the licensee revealed that the TSVs have a master-slave relationship with the TSV No. 2 being the master and the other TSV valves as three slaves. TSV No. 2 moves first and then TSV Nos. 1, 3 and 4 move in the same direction as TSV No. 2 when TSV No. 2 activates its 95 percent open relay. This logic is bypassed and inhibit logic is initiated when the test switch is depressed. The licensee unsuccessfully tried to replicate the scram condition. Technical Support personnel concluded that TSV No. 2 had travelled well past the 95 percent relay activation point and, when the test button was released, the inhibit circuit was defeated. This allowed TSV Nos. 1, 3 and 4 to start closing and activated their 95 percent open relays before TSV No. 2 could reverse direction with sufficient time to deactivate its 95 percent open relay, and reverse the direction of the other TSVs. The closing of all four TSVs past the 95 percent open position initiates an RPS trip. Additional investigation revealed that the contacts of the TSV No. 2 95 percent open relay were sluggish and operated after the actuation arm had moved. The licensee observed that it could vary the response time of the relay by tapping the relay. The sluggish relay was replaced. In addition, a jumper with a toggle switch was installed which would independently initiate the inhibit circuitry. Post maintenance testing indicated that the remedial action was successful. Technical support personnel should be commended for their diligence in pursuing the cause of the equipment malfunction.

The licensee commenced pulling control rods at 6:09 a.m. on March 5, 1992. Criticality was achieved at 10:19 a.m. and the unit was synchronized to the grid at 11:34 p.m.

b. On March 6, 1992, the inspector observed three fire doors in the DG building with faulty door hardware. One of the doors would not permit normal passage. Investigation revealed that trouble tickets had not been written on this item. The inspector was concerned that neither the auxiliary operators nor the hourly fire watch had identified these conditions. These items were discussed with the licensee. The doors were repaired and the operators and fire watches were reminded of the importance of identifying deficiencies.

c. On March 17, 1992, the Reactor Building Vent Exhaust Monitoring System Functional Test (OPT-04.1.1) was performed on Unit 2 with reactor power at 79 percent. The test isolates both primary containment hydrogen/oxygen monitors (CAC-AT-4409 and CAC-AT-4410) and places them in a recirculation mode. During the performance of the test, problems were identified with both monitors and, at 12:10 a.m. on March 18, 1992, they were declared inoperable. This placed the unit in an LCO (Technical Specification 3.6.6.4), which required the unit to be in startup (Mode 2) within eight hours. CAC-AT-4409 had a suspected failure of the sample pump seal and CAC-AT-4410 had a discrepant pressure regulator. An orderly shutdown was commenced at 2:10 a.m. Power was reduced to 23 percent at which point the licensee determined that the CAC 4410 pressure regulator could be repaired prior to the expiration of the LCO. The regulator was repaired and CAC-4410 was declared operable at 7:47 a.m., which placed the unit in a 31 day LCO. The second hydrogen/oxygen monitor was declared operable at 1:08 a.m. on March 20, 1992. ACR 92-199 was written to document the monitor failures and entry into the LCO.

During the power decrease, the operators were unable to reduce the speed of RFP 2B. A Motor Gear Unit (MGU) malfunction prevented turbine speed control of RFP 2B. Unit 2 power was increased to 60 percent after the CAC-AT-4410 pressure regulator was repaired. The licensee identified that the MGU mechanical linkage was binding and resulted in RFP turbine 2B speed control problems. Extensive troubleshooting resulted in the identification of a broken pilot valve cylinder guide in the MGU. The defective cylinder caused the guide to bend and resulted in misalignment and binding of the linkage. ACR 92-201 was written to document the defective RFP MGU. Following repairs and additional testing, RFP 2B was declared operable at 7:00 a.m., March 23, 1992. Power was immediately increased to 77 percent.

While at 100 percent reactor power, the Unit 1 operators observed speed oscillations on RFP 1B on March 18, 1992. Investigation revealed that the MGU transformer was overheating. The licensee was unable to stop the oscillations and commenced reducing reactor power at 6:31 p.m. RFP turbine 1B was isolated when sixty percent reactor power was reached. Troubleshooting indicated electrical problems, but the licensee was unable to pinpoint the source of the oscillation and replaced most of the MGU electrical/electronic components. RFP 1B was placed back in service at 4:41 p.m., and power was increased to 100 percent at 11:43 p.m., on March 20, 1992.

d. On March 21, 1992, the Unit 1 reactor sample valve (B32-F019) was cycled for the Reactor Drywell Inboard Isolation Valves Operability Test (SP-91-072). Later the operators noted that unidentified drywell leakage had steadily increased from 0.9 gpm to 2.02 gpm on March 22. The B32-F019 and F020 valves were shut in an attempt to identify the source of the leakage. The leakage rate decreased to 1.85 gpm and stabilized.

The RWCU isolation valve (F001) and RCIC inboard steam supply valve (F007) were backseated in an additional attempt to identify the source of the leakage. No decrease was noted and the F007 valve was returned to standby.

The unidentified drywell leakage steadily increased to 2.64 gpm at 4:00 a.m. on April 1, 1992. The licensee plans to reduce power and make drywell entry to determine the source of the unidentified leakage.

e. On March 31, 1992, the sample pump for Unit 1, CAC-AT-4410, failed. This is the second sample pump failure within 2 weeks. Inspection revealed that the pump diaghram had failed. The licensee does not have any qualified replacement pumps and plans to rebuild discrepant pumps.

The licensee also did not have any qualified diaghrams and had to qualify a diaghram to replace the defective part. They are in the process of obtaining qualified sample pumps.

The incidence of equipment problems does not appear to be declining. Improved unit log keeping has made this condition more visible to outside observers. Equipment problems create work arounds and, more importantly, divert the operator's attention. The inspectors expressed concerns that diverted operator attention caused by equipment problems could result in inappropriate operator action. The inspectors are also concerned about the large number of Unit 2 equipment problems which have been identified since completing the recent 115 day refueling outage.

f. While walking down the Unit 1 control panels on April 1, 1992, the inspector observed that the active thrust bearing temperature for RFP 1A was approximately 50 degrees F lower than that of RFP 1B. He noted that the active thrust bearing temperature for both Unit 2 RFPs was approximately the same as RFP 1B. The Control Operators, when questioned, were not able to provide an answer as to what caused the temperature differential nor did he appear to have observed the difference. The licensee determined that the chart recorder was reading actual temperatures and concluded that the RTD was out of its well. WR/JO 92-AHBB1 was written to troubleshoot the cause of the lower temperature.

g. The inspector observed that concrete shipping cask plugs were stored approximately six feet in front of a fire hose cabinet at the North side of the DG building. There is a sign on the door of the cabinet which reads, "Maintain 20 feet area in front of this cabinet clear at all times." The inspector informed the licensee of his observation. The area was cleared within one day.

Violations and deviations were not identified.

5. Onsite Review Committee (40500)
The inspectors attended selected Plant Nuclear Safety Committee meetings conducted during the period. The inspectors verified that the meetings were conducted in accordance with Technical Specification requirements regarding quorum membership, review process, frequency and personnel qualifications. Meeting minutes were reviewed to confirm that decisions and recommendations were reflected in the minutes and followup of corrective actions was completed.

There were no concerns identified relative to the PNSC meetings attended. The resolution of safety issues presented during these meetings was considered to be acceptable.

6. Safety Assessment/Quality Verification (40500)

a. The inspector observed corrosion on safety-related electrical conduits and an instrument air line at the 50 foot level of the Unit 2 Reactor Building near the RBCCW heat exchangers. There was a chemical buildup the size of a softball on a conduit, a golf ball sized buildup at an instrument air line union, and a large buildup on a condulet. There were also lesser amounts of buildup on other conduits and air lines. The areas surrounding the buildups had varying amounts of corrosion. The buildup appears to be caused by the leakage from the Spent Fuel Pool (SFP). On March 25, 1992, the inspector took the licensee on a tour of the affected area. The inspector is aware that the licensee is aware of the long term leakage from the spent fuel pool and that an annual inspection is conducted for this problem. However, the inspector is concerned about the licensee's tolerance for conditions which result in equipment degradation. The inspector discussed this concern with site management.

The Unit 2 SFP leak was identified in 1977. Despite extensive efforts, the licensee has not been able to determine its source. An evaluation was made of the effects on the structure and it was determined that concrete erosion was approximately 0.35 cu.ft./year. The licensee also determined that the loss of this amount of concrete would not have any effects on the structural integrity, and after the expenditure of approximately four hundred thousand dollars, terminated efforts to locate the source of the leak.

b. Seven Adverse Condition Reports (ACRs) were written for mispositioned valves during the reporting period. Five of the ACRs were for valves on Unit 2. They included the lube oil thermostats for DG Nos. 3 and 4 being set too low and a chilled water valve (2-T-CW-V14) found open and not included in Clearance 2-92-45; but also included spared RHR valve V48 open on Unit 1. Initial investigation revealed that Revision 40 is the most current valve lineup but the latest valve lineup had been made in accordance with Revision 32. Additional verification found one other valve (V26) out of position. Both valves were repositioned and independently verified. The licensee is investigating the circumstances surrounding the failure to incorporate the latest valve lineup revision.

Ten ACRs were written between October 3 and November 27, 1991, documenting mispositioned valves. ACR 91-609 was written on December 2, 1991, requesting a review to determine if an adverse trend existed. The response to this ACR stated that a review of the ten ACRs did not indicate that a significant adverse trend was developing or that previous corrective actions were inadequate.

Nine ACRs were written documenting mispositioned valves between December 8, 1991 and March 18, 1992. ACR 92-208 was written on March 19, 1992, requesting an evaluation of the effectiveness of past corrective actions. Subsequent to the issuance of ACR 92-208, two additional ACRs were written before the end of the inspection period documenting mispositioned equipment.

The response to ACR 92-208 is due by April 17, 1992.

7. Management Meeting

On March 18, 1992, the Director of DRP - I/II NRR and the Directors of DRP and DRS, Region II, and selected members of their staffs met with the CP&L Senior Vice President of Nuclear Power Generation and the Vice President - Brunswick Nuclear Project and members of his staff, to discuss recent events and CP&L's corrective actions for previous events. A tour of the plant preceeded the meeting.

8. Action on Previous Inspection Findings (92701) (92702)

a. (CLOSED) Unresolved Item 325,324/89-34-04 (IAP Item D1-2) Electrical Distribution System Re-evaluation. This item identified a concern with the availability of offsite power to the onsite electrical distribution system that was identified in the Diagnostic Inspection Report dated August 2, 1989. The licensee has developed an improvement plan which will add one additional diesel generator and an additional startup transformer with voltage regulators for each unit. These plans and a schedule for completion have been reviewed and accepted by NRR. The resident inspectors will monitor these modifications as they are installed. Based on the above, this item is closed.

Violations and deviations were not identified.

9. Exit Interview (30703)

The inspection scope and findings were summarized on April 3, 1992, with those perso indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

10. Acronyms and Initialisms

ACR	Adverse Condition Report
AO	Auxiliary Operator
BSEP	Brunswick Steam Electric Plant
CO	Control Operator
CP&L	Carolina Power & Light Company
DG	Diesel Generator
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EA	Enforcement Action
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
gpm	Gallons Per Minute
HP	Health Physics
HPCI	High Pressure Coolant Injection
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
IPBS	Integrated Planning, Budgeting and Scheduling
KW	Kilowatt
LER	Licensee Event Report
LCO	Limiting Condition for Operation
MGU	Motor Gear Unit
MST	Maintenance Surveillance Test
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OM&M	Outage Management & Modification
PA	Protected Area
PT	Periodic Test
PNSC	Plant Nuclear Safety Committee
PSID	Pounds per Square Inch Differential
QA	Quality Assurance
QC	Quality Control
RBCCW	Reactor Building Closed Cooling Water
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feed Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
RTD	Resistance Temperature Detector
RWCU	Reactor Water Cleanup
SCO	Senior Control Operator
SFP	Spent Fuel Pool
STA	Shift Technical Advisor
TS	Technical Specification
TSV	Turbine Stop Valve
URI	Unresolved Item
WR/JO	Work Request/Job Order