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

Report No. 50-325/92-02 and 50-324/92-02

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: February 1 - 29, 1992

Lead Inspector: for R. L. Prevatte, Senior Resident Inspector — 3/11/92 Date Signed

Other Inspectors: D. J. Nelson, Resident Inspector
P. M. Byron, Resident Inspector

Approved by: H. O. Christensen, Section Chief — 3/11/92 Date Signed
Reactor Projects Branch 1
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of surveillance observation, operational safety verification, and review of onsite review committee activities .

Results:

In the areas inspected, no violations or deviations were identified. A weakness involving the need to conduct outage walkdowns and inspections for systems, components and areas not accessible during power operation, due to high radiation levels, was identified, paragraph 4. Although not identified as a weakness, the licensee experienced numerous problems while attempting to restart Unit 2 after the February 2 scram. A significant number of these problems were on systems and equipment that were worked on during the recent refueling outage.

Unit 1 was operated at essentially 100 percent power except for a 2 day period when power was reduced to permit bypassing a feed water heater.

Unit 2 was either shutdown or operated at reduced power for all of the reporting period.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

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

   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)

   This area is covered under Special Report No. 92-04.

3. Surveillance Observation (61726)

   The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, 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:

OFIC-DPT001 Calibration of Rosemount Model 1153 Differential Pressure Transmitter for Drywell Post LOCA Venting Flow Transmitter 2-VA-FT-2577

During observation of the above c libration, licensee technicians identified several procedural inadequacies. These were submitted for correction on February 12, 1992. The inspector questioned the sequence used for returning the equipment to operation upon completion of ca libration, and asked why the tools needed to accomplish this task were not listed in the procedure. As a result, these items were also submitted for addition/correction in the maintenance procedure revision request. The inspector questioned the technician regarding these errors and, if similar errors existed in other procedures they had recently performed. Their response was that recent added management emphasis and QC presence in the field had resulted in new requirements for procedural compliance. This has resulted in many examples of procedural guidance which were less than fully adequate being identified. It appears that licensee management and supervision have not, in the past, created an atmosphere that required strict procedural compliance and ensured that procedural errors were corrected when found. The inspectors noted that a review of recently initiated QC inspections of maintenance and surveillance activities have identified procedural weaknesses and inadequacies.

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. The review of logs included those for control operator, shift supervisor, clearance, the jumper/bypass and no conflicts with Technical Specification Limiting Conditions for Operations were identified. 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 permits, 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.

a. On February 2, at approximately 4:00 a.m., power was reduced to 80 percent and Unit 2 commenced main turbine weekly valve testing. After testing the intercept, stop, and bypass valves, testing was started on CV No. 1. CV No. 1 tested satisfactory and the 1/2 scram signal on RPS channel A1 was reset. When CV No. 2 was tested, the normal turbine control valve fast closure B1 trip and load reject Channel "B" signal was received generating a 1/2 scram. When the operator released the control valve test push button, the B1 turbine control valve fast close pressure switch reset, but the A1 pressure switch for CV No. 1 immediately tripped before the operator had an opportunity to reset the B1 channel 1/2 scram. This resulted in a full reactor scram. This scram resulted in reactor vessel water level decreasing and the unit received a group 2, 6, and 8 isolation signal. HPCI and RCIC started on a low reactor water level of 115 inches. RCIC injected but the low level signal did not exist long enough to cause the HPCI injection valve to open. Some problems were experienced in getting the Startup Level Control Valve (SULCV) to open and RFP "A" seized up. After reducing feed pressure, the operator was able to open the SULCV and a normal shutdown was initiated.

   An investigation of this event by the licensee was initiated to determine the root cause of this event. This investigation found that the EHC pressure switch for CV No. 1 was very sensitive and may have actuated due to a drop in EHC header pressure when CV No. 2 was tested. This investigation also found, that the seals on EHC "A" and

"B" accumulators were defective. This resulted in over three gallons of EHC hydraulic fluid leaking past the seals and into the nitrogen side of each accumulator. This resulted in the EHC system being nearly solid.

A review of WR/JOs by the licensee revealed that both the "A" and "B" accumulators had been overhauled in November/December of 1991. New seals were installed at that time. The effect of the EHC system being solid may also have been a contributing factor to the trip. The licensee replaced the pressure switches on all four control valves and the seals on both EHC accumulators. Testing after these replacements indicated that the system was fully functional.

The licensee sent the EHC seals and CV No. 1 pressure switch to a laboratory for testing. The test results on the EHC accumulator seals found that turbine control valve movement caused hydraulic transients. These transients caused accumulator cylinder movement of approximately 1-1/2 inches per 100 psig. The pressure oscillations that resulted from turbine control valve movement were of insufficient magnitude to move the accumulator piston a sufficient distance to result in the EHC fluid lubricating the cylinder seals. The seal vendor stated that the expected life of the seal was 1 - 2 x 10^6 movements and that excessive movement without lubricant resulted in seal failure. The results of the tests on the control valve pressure switch indicated that the switch was operable but very sensitive. The overall test results indicate that the root cause of the reactor trip was a combination of a sensitive pressure switch, an EHC system that was nearly solid as a result of the accumulator seal failure and nitrogen entrainment in the hydraulic fluid which may have also increased the magnitude of surges seen on the EHC system when CV No. 4 oscillated. The licensee efforts in troubleshooting and root cause determination of the EHC accumulator seal failure has not been fully completed. However, efforts to date appear to be extensive and thorough.

Investigation into the excessive turbine control valve movements resulted in the licensee restricting power to less than 82 percent to prevent operation of CV No. 4. The licensee and turbine vendor are continuing to study this problem and develop a long term solution. The licensee is currently preparing an LER that will discuss the Unit 2 reactor scram and provide additional coverage of this item.

During the reactor scram on February 2, problems were also encountered with RFP A seizing up. An investigation determined that the retaining cap screws for the pump outboard wearing ring had broken and allowed the wearing ring to come in contact with the pump impeller. Further investigation into this issue revealed that the incorrect alloy material was used for the wearing ring retaining cap screws. The licensee, through a record review, determined that the material specified by the pump vendor was 410 SS. RFP 2A cap screws were made of carbon steel. A further record review was unable to determine what material was used for the retaining cap screws for RFP 2B. This review did determine that the cap screws installed in RFP 1A and 1B were 316 SS. A subsequent engineering review determined that the 316 SS was an acceptable substitution. The licensee installed the correct retaining cap screws in RFP 2A and completed the other repair activities on RFP 2A on February 10.

During control valve testing on Unit 1 on February 2, an auxiliary operator, through video observation, discovered that FWH 3B was having excessive lateral movement (approximately 4 - 6 inches), and the extraction steam supply line to the FWH 3B was vibrating more than usual. The unit was at 80 percent power for large valve testing at the time of the above observation. Since this area is a locked high radiation level, and Unit 2 had just experienced a reactor scram, the engineering staff decided to walkdown the Unit 2 FWH 3A piping since it was a mirror image of Unit 1 FWH 3B and extraction piping. This walkdown would allow engineering to familiarize themselves with the piping and component layout and also determine if Unit 2 had experienced the same movement.

The walkdown of Unit 2 FWH 3A found that 3 of the 4 anchor bolts were damaged and required replacement. A walkdown of Unit 2 FWH 3B also revealed damage to all heater anchor bolts and a loose support. The licensee developed a repair plan for the FWHs that replaced all damaged bolts. A review of the steam extraction lines found that two supports had been removed as a part of Plant Modification 86-040 which was implemented in 1987. An engineering review determined that these supports were still needed and they were reinstalled in Unit 2.

An inspection was conducted in Unit 1 FWH 3A and 3B. No significant damage was observed in FWH 3A. Repairs were required on FWH 3B, but since the unit was in operation, a decision was made to bypass the FWH 3B and perform the necessary repairs during a Unit 1 mini-outage scheduled for April or May 1992. Power was reduced to less than 30 percent and the FWH 3B was bypassed on February 4.

The above problems with the FWHs indicate that components, piping, and systems that are not accessible during power operation, because of high radiation levels, are not receiving adequate walkdowns during unit shutdowns and outages. This damage to components is not being identified and is a weakness that warrants additional licensee attention.

On February 6, the licensee commenced a restart of Unit 2 with only Reactor Feed Pump (RFP) 2B operable. The inspector observed numerous alarms and problems during the startup. These included problems with SRM "B" which could not be withdrawn and was initiating a rod block. SRM "B" was bypassed in order to clear the rod block. IRM "F" was spiking with IRMs "G" and "H" bypassed. The operators had difficulty maintaining vessel level because the Startup Level Control Valve (SULCV) was sticking open. The exciter coolant low-flow annunciator was lit. The steam packing exhauster vacuum was alarming and varying from 3" - 20". Water was found in the off-gas piping. Control Rod 26 - 39 was found to be inoperable and the Division 1 Suppression Pool Temperature Monitoring System (SPTMS) was out of service.

The inspector was concerned that the large number of alarms caused by inoperable equipment described above were a distraction to the operators. Working with these conditions diverted the operators' attention during the restart. Since they would not be able to go to the run mode with SPTMS and control rod 26 - 39 inoperable, the licensee, early in the morning on February 7, decided to abort the restart effort and placed the unit in hot standby.

In addition to the above, the main turbine would not stay on the turning gear. Discussions with the licensee revealed that the bull gear teeth on the main shaft had become excessively worn. The poor gear mesh resulted in unreliable and erratic turning gear motor operation. The licensee, after consultation with the turbine vendor, was able to develop an interim mode of operation that reduced the number of operating turbine lift pumps from 5 to 3. This reduction in lift pressure resulted in sufficient turning gear engagement for turbine heat up and cooldown. Replacement of the bull gear on the turbine shaft will require generator rotor removal and necessitate a major outage. The minimum lead time for purchase of a bull gear is approximately 31 weeks. The licensee's current plans are to attempt to improve gear mesh during a March mini-outage currently being planned for turbine EHC work and review plans for future bull gear replacement.

On February 11, the licensee commenced unit startup at 3:45 p.m. During the late afternoon of February 11, the licensee became aware of a problem concerning the seismic qualification of a module installed in the Foxboro interface cabinets that provide PAM indication. This problem, which was identified and discussed in NRC Information Notice No. 91-70, involved the seismic support rails and bumpers that maintain the individual modules in place during a seismic event. The licensee review of this notice for applicability to Brunswick had not been able to determine if the rails and bumpers were installed. Based on the above, the licensee took a conservative approach and shut Unit 2 down to permit an inspection of the cabinets. The unit was shutdown from 6 percent power at 6:44 a.m. on February 12.

An inspection on Unit 2 determined that all required supports were installed for "Q" class modules. The licensee then obtained the required parts and installed them for all non-"Q" modules in Unit 2. Using the experience gained on Unit 2, the Unit 1 installations were corrected without unit shutdown.

Unit 2 was then restarted on February 13 and returned to power. A restriction of 82 percent was placed on the unit due to the EHC/Control Valve problems discussed above.

On February 17, main turbine bearing No. 9 vibration increased to a level of approximately 9 mils. This resulted in reducing power to 80 percent with instructions to decrease power as needed to maintain the vibration level below 9 mils. Power was maintained at that level until an unusual noise was detected in RFP 2B on February 21. This noise was determined by engineering to be a resonant harmonic noise created when the pump was operated at approximately 4400 RPM. When the speed was reduced to less than 4330 RPM, the noise cleared. Instructions were provided to operate the unit at 77 percent power with RFP 2B speed less than 4330 RPM. Operation at this power level allowed balanced operation of both RFPs. The licensee intends to stay at this power level until the problems with No. 9 bearing coupling and the control valve oscillations and RFP 2B problems can be corrected. The licensee is currently planning a mini-outage to start on or about March 14 to perform maintenance activities and repairs on the above items.

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. Exit Interview (30703)

The inspection scope and findings were summarized on February 28, 1992, with those persons 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.

7. Acronyms and Initialisms

AO	Auxiliary Operator
BSEP	Brunswick Steam Electric Plant
CV	Control Valve
DPT	Differential Pressure Test
EHC	Electro Hydraulic Control System
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
FWH	Feedwater Heater

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
IRM	Intermediate Range Monitor
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
NRC	Nuclear Regulatory Commission
OM&M	Outage Management & Modification
PA	Protected Area
PAM	Procedures Administration Manual
PIC	Process Instrument Calibration
PNSC	Plant Nuclear Safety Committee
PSIG	Pounds per Square Inch Gauge
QA	Quality Assurance
QC	Quality Control
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feed Pump
RHR	Residual Heat Removal
RPM	Revolutions Per Minute
RPS	Reactor Protection System
SPTMS	Suppression Pool Temperature Monitoring System
SRM	Source Range Monitor
SS	Stainless Steel
STA	Shift Technical Advisor
SULCV	Startup Level Control Valve
TS	Technical Specification
URI	Unresolved Item
WR/JO	Work Request/Job Order