UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-325/95-15 and 50-324/95-15

Licensee: Carolina Power & 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: July 1 - August 4, 1995

Lead Inspector: ______________________ 9-1-95
C. A. Patterson, Senior Resident Inspector — Date Signed

Other Inspectors: P. M. Byron, Resident Inspector
M. T. Janus, Resident Inspector
J. L. Starefos, Project Engineer

Approved By: ______________________ 9-1-95
D. M. Verrelli, Chief — Date Signed
Reactor Projects Branch 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection included the areas of operations, maintenance and surveillance, engineering, and plant support.

Results:

In the Operations area, plant operators responded well to a Unit 1 reactor trip, paragraph two. This was a difficult transient with a group 1 isolation and failure of the electrical hydraulic control system. The plant nuclear safety committee and site incident investigation team conducted thorough reviews of the event prior to restart.

In the Maintenance and Surveillance area, the licensee determined that the cause of the Unit 1 reactor trip was the failure of the "A" electrical hydraulic control system pressure regulator, paragraph three. Two low water level trips occurred while the unit was shutdown. Although initially thought to be a problem with venting of the variable leg of the water level transmitter, a detailed root cause determination is being conducted.

In the Engineering area, the licensee conducted an evaluation of a local cooldown that exceeded the technical specification limit following the Unit 1 reactor trip, paragraph four. The engineering evaluation concluded there were no adverse effects from the cooldown.

In the Plant Support area, the composition, duties and response actions of the site fire brigade were reviewed, paragraph five. These items are clearly defined with a dedicated fire brigade from the loss prevention unit. A violation was identified by an NRC inspector when the presence of another inspector was overheard communicated among plant employees. A deviation was identified from the final safety analysis report for the poor material condition of two flood doors in the service water building.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   *R. Anderson, Vice President - Brunswick Nuclear Plant
   G. Barnes, Manager - Training
   A. Brittain, Manager - Security
   *W. Campbell - Vice President - Engineering
   *J. Cowan, Director - Site Operations
   *N. Gannon, Manager - Maintenance
   *J. Gawron, Manager - Environmental & Radiological Control
   *R. Lopriore, Acting Manager - Brunswick Engineering Support Section
   *G. Honma, Supervisor - Licensing
   *W. Levis, General Plant Manager
   J. Lyash, Manager - Operations
   *D. Hicks, Manager - Regulatory Affairs
   *M. Marano, Acting Manager - Site Support Services
   D. McCloskey, Manager - Outage and Scheduling
   N. Schlichter, Acting Manager - Nuclear Assessment
   M. Turkal, Supervisor - Regulatory Compliance

   Other licensee employees or contractors contacted included licensee reactor operators, auxiliary operators, craftsmen, technicians, and public safety officers, in addition to quality assurance, design, and engineering personnel.

   NRC Personnel

   *C. Patterson, Senior Resident Inspector
   *P. Byron, Resident Inspector
   M. Janus, Resident Inspector
   J. Starefos, Project Engineer

   On July 10, 1995, a public meeting was conducted at the site to present the Systematic Assessment of Licensee Performance. The details are discussed in Inspection Report 325,324/95-99.

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

2. Operations

   a. Operational Safety Verification (71707)

      <u>Unit Status</u>

      Unit 1 ended 51 days of continuous operation when a reactor trip occurred on July 13, 1995. The trip is discussed in detail in this report. The unit returned to power generation on July 17, 1995. At the end of the period, 17 days of continuous operation were completed.

Unit 2 operated continuously during the period and completed 399 days of operation. Indication of fuel pin leakage occurred around July 23, 1995, during a down power to 60% power. The licensee implemented procedure OENP-24.21, Fuel Integrity Monitoring, to identify the fuel failure using power suppression testing. Two control rods were fully inserted to minimize the leaking fuel bundles power level.

Unit 1 Reactor Trip

On July 13, 1995, at 11:58 a.m., Unit 1 experienced a scram from high reactor flux while at 100% power. The scram was closely followed by a Group 1 isolation signal when reactor pressure went below 850 psig and the MSIVs closed causing a second scram signal. The MSIV closure resulted in reactor coolant shrinking to the Low Level 2 setpoint which initiated a third scram signal and initiation of HPCI and RCIC. Groups 2, 3, 6, and 8 isolation signals were also received. All systems functioned as designed. The inspector proceeded to the control room immediately after the event and observed recovery operations. The operators used their emergency procedures; and command and control was good. There was excellent management support including five additional SROs to assist. The inspector considered that operator performance was very good. The licensee made the appropriate notifications to the NRC.

Approximately 10 minutes before the Unit 1 scram, the licensee experienced an increase in control building pressure, as well as, heating inside some of the Unit 1 relay cabinets. While the operators were attempting to locate the cause of the increase in the building pressure and cool the cabinets using portable fans, reactor pressure started to decrease. At 11:53 reactor pressure was decreasing at a rate of 20 psi/min and two minutes later a series of APRM upscale alarms initiated and cleared. The operators also observed cycling of the BPVs. The Shift Superintendent was preparing to insert a manual scram when the reactor scrammed on high flux at 11:58. The MSIVs closing resulted in reactor coolant shrink. Group 2, 6, 8 and SDC isolations were received at LL1(162.5"). Group 3 and RWCU isolated, HPCI and RCIC initiated, and the recirculation pumps tripped at LL2(112"). RCIC injected for approximately 90 seconds before it was secured and HPCI did not inject as level recovered beyond its setpoint. Makeup increased reactor level causing HPCI, RCIC, and RFPTs to trip on high level at 12:00. Stable conditions were maintained by operating HPCI and RCIC in the level and pressure control modes and cycling the SRVs to control pressure as required. The operators needed to initiate reactor coolant circulation to prevent stratification in the vessel. Recirculation pumps could not be restarted as the T.S. requires a steam dome to bottom head temperature differential of less than 145F. They were unable to obtain the differential temperature because isolation of the RWCU prevented the licensee from obtaining adequate bottom head drain temperatures as there was no flow in the drain line and CRD was injecting cold water in the area.

The cycling BPVs indicated to the operators that the plant had experienced an EHC failure. They did not know the failure mechanism and elected not to implement a cooldown using the condenser. They were concerned that the BPVs might cycle resulting in a rapid uncontrolled cooldown. The operators initiated a cooldown using CRDs, HPCI, RCIC, and SRVs. The inspector observed that the cooldown was controlled by reducing reactor pressure. At 2:33 p.m., a second scram was experienced due to low reactor coolant level caused by shrink after an SRV was shut. The licensee opened the MSIVs to use the main condenser for cooldown at 3:34 a.m., on July 14, after determing the EHC failure mechanism. The unit experienced a third scram from a low reactor level signal at 10:54 p.m., on July 14, with reactor pressure at 68 psig and actual level at 218 inches. Group 6 and partial Group 2 and 8 (outboard valves) isolations were received. The operators suspected a variable leg perturbation. At 4:25 a.m., on July 15 a fourth scram was received which was identical to the previous scram except the reactor pressure was 40 psig.

The licensee's investigations determined that the cause of the scram was the "A" EHC pressure regulator failed low, then failed high while the "B" regulator was in control and became controlling when it failed high. The turbine control valves opened to reduce pressure to the regulator's set point and the BPVs opened to assist the control valves. The BPVs cycled and when they slammed shut a high pressure pulse was generated in the reactor which in turn collapsed voids causing a power spike. The inspector reviewed the ERFIS traces and observed the steadily decreasing reactor pressure. The cycling control valves were clearly delineated as were the APRM high flux indications. The traces for BPV position and reactor level were overlapping which made them hard to read. The licensee was able to retrieve the event data from the process computer. The engineers were able to produce cleaner traces from the process computer making it easier to view the sequence of events.

A SIIT was organized shortly after the event to determine the root cause or causes of the July 13 scrams and recommend additional problems to be addressed before restart. The SIIT investigation determined that the "A" EHC pressure regulator failure was the cause of the scram. Five EHC control cards were replaced in the "A" regulator. The licensee reviewed bottom head drain temperatures and bottom head drain thermocouple readings and determined that they had exceeded the T.S. cooldown limit of 100F/hr in the bottom head area of the reactor vessel. The T.S.

required an engineering evaluation of the cooldown prior to restart. The licensee also addressed low oil level in a recirculation pump and feed water head valves which failed to reseat.

The PNSC met on July 14, to review the SIIT report which included the engineering evaluation of the cooldown and again on July 15, to review the status of the corrective actions. They also reviewed the cause and corrective actions for the two scrams of July 14 and 15. The system engineer discussed the cause of the control building high pressure and that it did not induce the EHC failure. He determined that an electrician pulling cable in a cabinet inadvertently bumped a relay which activated the Tornado Pressure Check Damper. The PNSC concurred with the root cause determinations and voted to authorize restart when corrective actions were complete. The inspector attended both meetings and concluded that the PNSC posed substantive and thorough questions.

On July 16, at 5:39 a.m., the licensee commenced pulling control rods and achieved criticality at 12:48 p.m. The repaired EHC was tested by switching the control from one regulator to the other and back again with one BPV 75% open and reactor pressure at 150 psig. The inspector reviewed the process computer trace and noted that the changes were smooth. The licensee had a great deal of difficulty moving rods from the 00 position and the inspector observed that it took almost 90 minutes to move one rod. The Shift Superintendent eventually set a limit of 15 minutes and the collet and fingers were flushed. The control rod drive was to be vented if movement did not occur 15 minutes after flushing. Venting was not required. The operators also experienced difficulty in moving rods above the 02 position but at a significantly less frequency. Subsequent testing has demonstrated that the difficulty to move rods only is applicable for out motion. The difficulty in pulling rods is demonstrated by the time it took from initial rod pull to turbine synchronization. It took 27.5 hours versus the normal 10-12 hours to perform this evolution. The system engineer is of the opinion that there is debris in the rod drive filters. The unit was synchronized to the grid at 9:01 a.m., on July 17. The inspector observed all recovery operations through unit synchronization. In addition to the PNSC meetings, he observed the management recovery prioritization meeting and SIIT meetings. The inspector observed that the operators did a good job of recovering the unit from the trip as well as placing it in a stable condition with the equipment limitations placed on them.

SCBA Usage

The inspector reviewed the licensee's requirements for conditions which require the use of SCBAs in the control room to operate the unit and the availability of SCBAs. The licensee has no conditions which require the use of SCBAs to operate the unit from the control room. The unit is designed so that it can be operated or shutdown from outside the control room. The use of SCBAs is at the shift supervisor's discretion. There are adequate SCBAs available for the operators; and in addition, those necessary for ASSD are located outside the control room. Spare air bottles are readily available in a nearby building as the licensee uses a one hour air bottle. The SCBAs are under the cognizance of the LPU which maintains approximately 70 SCBAs onsite. All personnel who may possibly be required to use an SCBA are qualified which includes operators, E&RC, LPU, Maintenance, and the NRC resident inspectors.

Operator Turnover Meetings

The operators recently changed the way they hold turnover meetings in order to reduce congestion in the control room. Two turnover meetings are now held. The first meeting is held in the control room and is restricted to Operations personnel. The second is held in the WCC conference room after the Operations turnover. The shift superintendent runs the meeting and it is attended by Maintenance, E&RC, LPU, WCC supervisor, FIN team, and the outside SRO. Plant status and the previous days events are discussed. In addition, the work scheduled for the next 24 hours is discussed. The inspector considers this to be one of the more significant meetings held as it is a forum for all organizations involved to discuss concerns and request assistance. The inspector has attended both turnover meetings and has observed that there appears to be a lack of commitment by some of the support organizations. He has asked several unit managers about their view of the importance of the second turnover meeting and all have stated that they consider it important. The inspector has discussed his observations with the licensee. The licensee is in the process of developing a policy which will specify the attendees at the second turnover meeting.

Third Party Reviews

During this period the inspector reviewed third party visit reports. The inspector was briefed by the licensee after each visit. The inspector reviewed the following reports:

Topic	Visit Date
Human Performance Enhancement	October 3-6, 1994
Work Management Process	November 14-18, 1994
Outage Preparations	February 28-March 2, 1995

Work Packages, Work Practices and Procedure Use	April 19-21, 1995
Chemical Control	May 3-5, 1995

The inspector concluded from the review that it was consistent with the most recent NRC perception of the licensee's performance. There were no substantial deviations.

b. Self-Assessment (40500)

PNSC

The inspector attended the July 14 and 15, 1995, PNSC meetings during which the SIIT report of the July 13 scram was discussed and preparations for restart were reviewed. The SIIT report addressed the root cause of the event, failed EHC pressure regulator, and recommended corrective actions to be completed prior to restart. During the July 15 meeting, the status of the corrective actions was reviewed. The chairman solicited additional concerns and all new issues were addressed. The PNSC authorized restart when all designated open issues were resolved. The inspector considered that the questioning was thorough and less than satisfactory answers were challenged. The PNSC addressed all relevant issues. The inspector considered that the PNSC did a good job in addressing all the issues prior to authorizing restart.

No violations or deviations were identified.

3. Maintenance and Surveillance

a. Maintenance Observation (62703)

EHC Failure

The licensee determined that the Unit 1 "A" EHC pressure regulator failed on July 13, causing the unit to scram. The pressure regulators are monitored by ERFIS at two points, at the output of the Main Steam Pressure card and the output of the second Steam Line Resonance Compensator card. A review of the ERFIS data revealed that the Main Steam Pressure output for both channels was identical. The output for the compensator cards was not the same and the signal from the "A" channel was distorted. The licensee was unable to determine which card failed, as there was no data available for the cards between the ERFIS points. They elected to replace the four "A" cards between the ERFIS data points and the "A" pressure sensor which had been drifting. Trouble shooting was performed using heat and vibration and the failure could not be replicated. The "A" cards were taken to the shop, calibrated, and found to be within specifications. The licensee has not been able to find any faults in the cards and plans to send the cards to GE for analysis. The licensee encountered a great deal of difficulty in obtaining replacement control cards as the installed EHC system is obsolete. The vendor has not made new cards for about ten years and other utilities were reluctant to relinquish their inventory. The replacement parts were obtained from several utilities and one card had to be modified prior to usage. The new cards were installed and two additional monitoring points were added for the pressure amplifier and the first resonance compensator outputs. Modification testing consisted of having the "A" regulator control at approximately 150 psig steam pressure; switching to the "B" regulator controlling; and back to the "A"in control with a BPV partially opened. The inspector observed this test and noted no changes to plant parameters. He also reviewed the process computer traces and noted that the transitions were clean. The licensee considered the test successful and continued the power ascension with no further problems.

Venting of Water Level Instrument Legs

The licensee's initial investigation of the July 14 and 15 low level scrams revealed that perturbations were noted on all of the level instruments common to the variable leg connected to the N11B nozzle at the 142 inch level. They concluded that entrained gas had migrated to a vertical run of the variable leg causing the indicated level to decrease. The level dropped below Low Level 1 (142 in.) which generated a scram signal. A review of maintenance records revealed that instrument piping had been replaced in the "B" variable leg during the recent refueling outage. The pipe was purged after the weld was completed and the system was backflushed, filled, and vented. The I&C technicians reviewed their filling and venting techniques to determine if the piping could retain entrained gas. The technicians noted that there was an excess flow check valve in the reference and variable legs which would close with flow greater than 4 gpm. The excess check valve could restrict filling if it closed before the system was backflushed. Backflushing, filling, and venting were usually accomplished in accordance with Special Process Procedure, OSPP-PIX001, Backflushing Rack H21-P009 and H21-P010 Instrument Piping. The test rig used to accomplish this task contains a check valve to prevent contamination of the demineralized water and a pressure gauge to ensure that demineralized water pressure exceeded system pressure to obtain flow. The technicians did not control nor were they able to quantify backflush flow. The technicians developed an improved method for backflushing which incorporates a flow meter in the test rig. WR/JO 95-AGHI1 was written to fill and vent the level instruments in both variable legs. The technicians were able to vent gas from five of the nine level instruments in the "A" leg and three of the seven level instruments in the "B" leg. The inspector discussed the new venting method with the technicians. They stated that they connected the test rig to the variable drain valve and then one at a time, filled and vented each instrument connected to the leg. The operators observed that the evolution was not reflected in the control room. The technicians consider that the new backflushing method, used in the implementation of WR/JO 95-AGHI1, was significantly better than the method previously used. The licensee is in the process of writing a procedure to incorporate flow measurement during filling and venting. Discussions with the licensee indicate they now believe that the inability to verify or determine flow was a weakness in the old filling and venting procedures. The licensee documented this event in CRs 95-01883 and 95-01885 and it will be reported to the NRC in LER 1-95-015.

The licensee's investigation of the high pressure in the control building determined that it was caused by the closing of the Unit 1 Tornado Pressure Check Damper. The damper is designed to automatically close on very low outside pressure or by a switch in the control room. The closed damper eliminated the discharge path for the control building which resulted in the high pressure condition. A modification for battery room ventilation was being installed at the time of the event. The system engineer investigating the event determined that a technician was pulling cable in the cabinet which contains the relay which controls the tornado damper relay. The technician indicated that he might have possibly jarred the relay causing the damper to close. The investigation did not identify any other probable cause. The licensee determined that the closing of the tornado damper had no causal effects for the scram but did provide a distraction to the operators.

DG Service Water Pipe Replacements

During the weeks of July 16, and July 23, 1995, the licensee conducted maintenance outages on DGs 1 and 2 respectively. The primary purpose for performing these two outages was to complete the installation of the Service Water pipe replacement plant modifications 91-070 and 91-071. The Service Water piping runs had been previously installed during the past two Unit 1 and Unit 2 outages. The remaining work involved the installation of the final piping connectors from the two Service Water valves to the jacket water header, and the installation and termination of the motor operators for the valves. This work was previously completed for DGs 3 and 4 during the last Unit 2 refueling outage. The licensee also utilized the time to perform routine maintenance on DGs 1 and 2 and work any necessary trouble tickets during these outages.

During acceptance testing for the work on DG 2, the service water valves failed to properly operate. Point to point checks were made for all wire terminations completed as part of this work package. These investigations revealed that a conductor was incorrectly terminated in the MCC panel. This work had been previously reviewed and accepted by QC prior to the performance of the acceptance test. WR/JO 92-AFZZP was modified to include instructions to lift this conductor and reterminate it on the correct terminal. Investigation into the root cause determined that the technician lifting the lead incorrectly identified the originating terminal and carried this error over to the retermination of the wire. Following the completion of this work, QC was called out to reinspect and verify the work. The valves were then successfully retested and performed as designed.

The inspector observed various portions of the work in progress throughout both DG outages. The inspector noted that all necessary tools and materials were properly staged and available, procedures were current and available for use in the field, and the crews were knowledgeable of their tasks. The inspector notes that both outages were completed ahead of schedule, without any major difficulties or problems.

b. Surveillance Observation (61726)

On August 2, 1995, the inspector observed performance of a portion of surveillance test OMST-CLDET11M, Chlorine Detection System Channel Functional Test. The inspector observed testing on a control building detector, 1-X-AT-2977. The inspector entered the ventilation ducting and observed placement of a chlorine source around the sensor. No response was observed. The technicians stopped the test and informed the control room of the problem, The chlorine source was a cotton swab soaked with chlorine bleach in a plastic bag. The technician had satisfactorily tested four detectors at the service water building and thought the chlorine source had depleted. A new source was obtained and the test was satisfactorily completed. The inspector reviewed the test procedure in the field and all the proper signatures were made in the procedure. Good communications and coordination with the control operators was observed. The inspector concluded the test was satisfactorily performed in accordance with the procedure.

c. Followup - Maintenance and Surveillance (92902)

(CLOSED) LER 1-95-03, Failure to Maintain Emergency Diesel Generator Staggered Testing Requirements. This LER dated May 4, 1995, documented the licensee's past failure to perform diesel generator testing on a staggered basis in accordance with TS. This item was previously discussed in greater detail in NRC IR 324,325/95-13, where it was identified as a Non-Cited Violation (95-13-01) in response to the licensee's efforts in identifying and correcting this item. The licensee has completed their corrective actions, which the inspector has reviewed and finds acceptable to prevent recurrence of this event. Based on the completion of these corrective actions, the inspector considers this item closed.

No violations or deviations were identified.

4. Engineering (37551)

Water Level Perturbations

During the root cause determination of the two Low Level scrams (CRs 95-01883 and 95-01885), an engineering evaluation determined that the events could have been caused by perturbations in the reference leg rather than the variable leg. Additional evaluation is ongoing to determine the root cause. The licensee has obtained the services of FPI to aid in determining the root cause. They plan to obtain outside hydraulics expertise to assist in understanding the observed phenomena. The initial assessment of the data may not have been adequate. The licensee expects to have the root cause determination completed by the end of the next inspection period.

Cooldown During Scram Recovery

The licensee experienced both a heatup and cooldown which exceeded the T.S. limit of 100F/hr during the recovery from the July 13 scram. The transient resulted in the recirculation pumps tripping and RWCU and SDC isolating which placed the plant in a condition where it had no forced circulation in the reactor vessel. The CRD pumps were operating and provided no driving force for coolant circulation, but did add cold water to the bottom of the vessel. The operators were focussing their efforts on placing the unit in a stable condition and were not able to restart the recirculation pumps within 30 minutes. T.S. 3.4.1.3 does not allow the recirculation pumps to be restarted if the temperature differential between the steam dome and bottom head drain line exceeds 145F. The RWCU pump takes part of its suction through the bottom head drain line which provides the motive force for flow. There is no flow in the bottom head drain line when RWCU is isolated and indicated temperatures are not accurate without flow. The line is small and indicated cooldown will be rapid in a no flow condition. This will cause the differential temperature to quickly exceed the T.S. limit. Procedural restrictions prevented the licensee from initiating RWCU and SDC with differential temperatures in excess of 145F. The licensee obtained bottom head drain temperatures from a strip chart and noted that the temperature decreased approximately 300F in two hours which exceeds the T.S. allowed maximum cooldown of 100F in any hour. T.S. 3.4.6.1 requires an engineering evaluation of the effects of the cooldown on fracture toughness and a determination that the system is acceptable for continued operation or be in Hot Shutdown within 12 hours. The licensee had Structural Integrity perform the evaluation as they had generated the recently revised

Pressure-Temperature curves for both units. The evaluation concluded that the cooldown had no effects on the structural integrity of the Unit 1 reactor vessel and the reactor vessel was acceptable for continued operations. In addition, the unit was in Hot Shutdown. The inspector considers that the licensee met all the requirements of the T.S.3.4.6.1 action statement. The PNSC reviewed the evaluation prior to authorizing restart. The inspector reviewed the evaluation and noted that Structural Integrity considered that the cooldown was of a lesser consequence as it occurred at the bottom head area and not at the beltline.

The licensee also experienced a heatup which exceeded 100F in one hour when attempting to induce flow in a recirculation line. A previous evaluation bounded the event. The recirculation water temperature is measured by RTDs on the bottom of the line. The licensee has concluded that the event was caused by cold stratified water on the bottom of the recirculation pipe being suddenly heated as the velocity of warmer water increases to cause turbulence which resulted in mixing of the layers. The inspector noted that neither bulk heatups or cooldowns exceeded the T.S. limit. The inspector also reviewed GE SIL 517, Single Loop Operation, and noted that there are no recommendations on ways to avoid excessive heatup. The SIL states "When warming a cold idle loop, there is no means of controlling the heatup to the recommended rate of less than 100F per hour and rapid thermal transitions can occur." The licensee evaluated that the heatup transient placed no operational restrictions on the Recirculation system in ESR No. 9501175.

Slow Control Rod Withdrawals

During the Unit 1 restart on July 16, 1995, following the July 13 reactor trip, control rod withdrawal was a slow, laborious process. The control operators manipulating the control rods had difficulty getting the control rods to withdraw from the full in "00" position. Normal withdrawal attempts were met by resistance to movement until drive water differential pressure was increased and several attempts had been made. Most control rod withdrawals required 5 to 8 minutes on average to move the rod off of the "00" seated position. Some rods required as much as 30 minutes, with operators working for 1.5 hours on one rod in particular. Slow control rod withdrawal problems had been previously experienced, but not to this extent or magnitude. Problems with the withdrawal process continued even after the rods were off the "00" position; many rods required increased drive water differential pressure to move them from intermediate positions as well. This effort to withdraw the control rods significantly delayed the restart process and was documented in Condition Report 95-1888.

On July 22, Unit 1 experienced this same slow withdrawal process while performing periodic test OPT-14.1, Control Rod Operability Check. This test is performed once per week to determine the operability of the control rod drive system in accordance with TS. This test inserts the control rods one notch and then withdraws them to their original positions. During this testing, 56 control rods experienced difficulty being withdrawn to their original full out positions. The system engineer was called in to assist with the testing, and rod movements. The rods were eventually withdrawn after numerous attempts, flushes of the collet piston seals, and increasing CRD drive water differential pressure. During July 28-30, 1995, flushes of the collet piston seals were conducted. This significantly improved the withdrawal times. During OPT-14.1, only 10 rods experienced difficulty being withdrawn. Since this difficulty started after the Unit scram, the licensee is aware to expect this problem again should the unit trip.

In reviewing CRD performance data, the licensee suspects that the problem started during the 1992 outage. Prior to this time, minimal control rod problems had been experienced on either unit. Withdrawal problems were experienced during each rod pull coming out of the extended outage in 1994. Unit 2 has had minor problems with a few control rods sticking on withdrawal, but nothing to the extent and magnitude of Unit 1's problems. The system engineer has been investigating the problem, and based on the recent experiences, suspects that crud trapped in the upper CRD seals may be the cause of the problems. One of the principle suspected sources of this crud is the swarf from the shroud modifications performed during the extended 1992 outage. The crud theory is based on the fact that flushing the collet piston annulus seals has reduced the high stall flows seen on many of the stuck rods and allowed the rods to be withdrawn. Another suspect is air or gases trapped in the seals, however this is not likely based on the stroke flushing method used to fill and vent the drives. The final suspect is damage to, or crud blocking of the finger filters, reducing flow to the collet piston. Currently the licensee does not have a root cause; this determination will be made during the next outage when a CRD is removed and inspected.

The problems experienced with the CR withdrawal does not affect the insertion or scram functions of the CRDMs. The licensee has reviewed the scram time data from the two most recent scrams following the last refueling outage and determined that the times are well within the specifications. To date no problems have been experienced with slow or stuck rods during rod insertions or scrams. The licensee has contacted others licensees, and has not found evidence of this type of problem elsewhere.

No violations or deviations were identified.

5. Plant Support (71750)

a. Fire Protection

As part of a regional initiative, taken in response to a recent fire at another facility, the resident reviewed and discussed the composition, duties, and response actions of the site fire brigade with the unit manager. The Brunswick fire brigade is composed from the LPU, a dedicated unit whose primary responsibility is emergency response. They are trained to respond and are responsible for the protection of personnel, facilities, and property. They are responsible for the implementation and maintenance of the fire protection, prevention, suppression, and hazardous material programs, as well as, the emergency response team.

LPU is immediately notified by the Control Room on the receipt of any fire alarm on the fire alarm panel, or any reports from the field of a fire (any evidence of combustion identified by smoke, heat, and/or visible flames). The five shift fire brigade members, and any additional members who are notified to return to the site to assist with the event will combat the fires in accordance with the Pre-Fire Plan. The fire brigade staffing remains at a minimum of five people per shift, and drills are conducted during all shifts, including backshifts.

In accordance with the Brunswick Plant Emergency Procedures, the licensee will make a declaration of a Notification of an UNUSUAL EVENT for any fire in the protected area lasting longer than ten minutes. A declaration of an ALERT is made for any fire which could potentially affect vital safety-related equipment. A SITE AREA EMERGENCY is declared for any fire that impairs the operability of any vital equipment which in the opinion of the Site Emergency Coordinator, is essential to maintain the plant in a safe condition. A GENERAL EMERGENCY is declared for any fire which in the opinion of the Site Emergency Coordinator could cause massive common damage to plant systems. The magnitude, location, and type of fire would dictate if offsite fire fighting assistance would be requested. If requested, the offsite assistance would serve a support role in fire fighting activities with LPU maintaining the overall control and coordination of activities.

b. Hurricane Preparedness and Flood Review

During the period of June 19-23, 1995, the inspectors reviewed hurricane preparedness with specific emphasis on flood protection installed in the plant. UFSAR section 3.4.1.1.1, Protection of Access Openings Below Maximum High Water Elevation, addresses specific doors and door frames as designed to limit the inleakage from the PMH condition to 5 gpm for personnel doors. Specifically addressed in UFSAR section 3.4.1.1.1.d, Service Water Intake Structure, are two personnel doors at Elevation 23.0 ft MSL. Of these two doors, the South entrance door had a poor material condition in that there existed a rusted gap at the bottom of the door. There was a one inch rusted gap that would preclude the door from limiting the inleakage from the PMH condition to 5 gpm as required by the UFSAR. Upon discussion with the licensee, a level 2 CR was written to address this issue. In addition, the North SW building entrance door was missing the bottom portion of the sealing surface sill which extends around the frame of the door. This gap would preclude the door from limiting the inleakage from the PMH condition to 5 gpm as required by the UFSAR. The North and South SW building doors are identified as two examples of a deviation from the UFSAR, DEV 50-325,324/ 95-15-01, Poor Material Condition of Flood Doors.

In addition, UFSAR Section 3.4.1.1.1.b, Diesel Generator Building, addresses one equipment access rolling steel door at Elevation 23.0 ft MSL. The licensee determined that there was not documentation from the vendor to show that the door would meet the UFSAR requirement to limit inleakage from the PMH condition to 15 gpm for rolling steel doors. The licensee is evaluating this issue.

There was a discrepancy in UFSAR section 3.4.1.1.1.b.1, Protection of Access Openings Below Maximum High Water Elevation - Diesel Generator Building, which described two personnel doors at Elevation 23.0 ft MSL. This is inconsistent with CP&L Specification Number 024-001, Specification for Special Doors, which describes four doors on the DG building at Elevation 20'-0". Both of these documents appear to be in error as there are two doors at the 20 ft level and two doors at the 23 ft level in the field, and the two doors at the 20 ft level are watertight type doors. The licensee determined that the watertight doors at the 20.0 ft level were the UFSAR doors, and that the UFSAR Section 3.4.1.1.1.b.1 incorrectly states that the two personnel doors are at Elevation 23.0 ft MSL.

OAOP-13.0, Attachment 3, addresses doors which are required to be closed during severe weather. This attachment, however, addresses closure of the Service Water Building North and South entrance doors designated as doors numbered 1 and 2. In the field, the doors were physically labeled with numbers 3 and 4. The licensee stated that the procedure is correct, and the doors in the field are mislabeled. The licensee plans to correct these numbers when the doors are replaced.

c. Radiological Controls

On August 2, 1995, the inspector toured the Unit 1 reactor building and observed that housekeeping had deteriorated. Tape was observed on the floor on the 20 foot level by the South HCU bank and on the 50 foot level by the SBGTs. Trash was observed in a radiological drain bucket at the RCIC turbine. Pens, pencils, and paper were observed under the grating in both feedpump rooms. The inspector also observed, at the reactor building purge fans on the 80 foot level, a green poly bag of rags under the support for the near duct and a bright yellow rag on a far duct, both were inside a contamination barrier. Standard radiological practice is to assume everything inside a contamination barrier is contaminated. It is also standard radiological practice to store contaminated material in yellow poly bags and noncontaminated material in green bags. The inspector discussed the housekeeping issues with Operations and they were addressed. He discussed the radiological issues with E&RC management. The tape in the drain bucket was used to secure the hose but it became wet and lost its adhesiveness. The tape was considered inappropriate by the licensee and removed.

The storage of material inside the barrier was discussed at length with E&RC management. The inspector was unable to locate any procedural guidance which addressed this. The licensee stated that the bag contained treated rags used by the Deconners who kept them in green bags so they would know which rags were clean. The licensee informed the inspector that they were trained to keep clean rags in green containers and remove them from the area in yellow. The inspector asked the licensee what policy or procedure delineated this area of training. They were unable to provide a response and requested time to research the issue. This will be a URI 50-325,324/95-15-03, Procedure for Storage of Material in Contaminated Areas, pending review of the licensee's response. The inspector did not observe any personnel in the area. The licensee explained that decontamination efforts were in progress in the area where the inspector observed the yellow rag on the duct.

d. Communicated Presence of an NRC Inspector

On August 2, 1995, the inspector entered the control room to discuss the results of a surveillance test with plant operators. While standing at the Unit 1 Unit operator's desk, the SRI inspector overheard some communication by plant personnel outside the control room on a portable hand-held radio. Plant personnel outside the control room communicated to other plant personnel, warning of the presence of an NRC inspector in the reactor building. The inspector discussed the conversation heard with the operator. The operator promptly raised the issue with the shift supervisor and other operations management. Later, the SRI learned that a RI had been touring the reactor building and was the subject of the warning.

The inspector concluded this was a violation of 10 CFR 50.70, Inspections, that requires the presence of an NRC inspector not be communicated. This violation will be identified as VIO 50-325, 324/95-15-02, Presence of NRC Inspector Communicated.

e. Organizational Changes

Nuclear Assessment Department Restructuring

Effective May 30, 1995, the organizational structure of the CP&L Nuclear Assessment Department changed. Following a T.S. submittal and change of the FSAR, the structure was decentralized and localized at the individual sites. The corporate organization known as NAD was eliminated and replaced by site Nuclear Assessment Sections at the sites and the Performance Evaluation Section in the corporate office. The individual site NAS structure functions as before, except they no longer report to a corporate office; they work directly for the site vice president.

PES is the corporate wide organization which reports to the vice president of Nuclear Services and Environmental Support. The structure and charter of this organization was spelled out in a change to Chapter 17 of the FSAR. One of the function of PES is to perform reviews of the independence and effectiveness of the individual NAS organizations. Additionally, they conduct the regulatory required inspections of the Operations, Maintenance, Engineering, Plant Support, and Environmental and Radiation Control areas. The group is additionally charged with performing senior management requested reviews, as well as, those from the individual site managers.

Management Changes

On July 18, and August 4, 1995, CP&L announced a series of management changes, affecting the Brunswick Station. The changes become effective September 1, 1995. The first change involved the naming of Roy Anderson, current Vice President, Brunswick Nuclear Plant, to Vice President, Fossil Generation. The Brunswick Vice President position will be filled by Bill Campbell, currently Vice President, Nuclear Engineering. Bill Habermeyer, currently Vice President, Nuclear Services and Environmental Support has been named to fill Bill Campbell's position as Vice President, Nuclear Engineering. John Paul Cowan, Brunswick Site Director, will become Manager, Nuclear Services and Environmental Support

Department. Bill Levis, Brunswick General Plant Manager will become Site Director. Rich Lopriore, Acting Engineering Manager will become General Plant Manager. John Holden, Design Engineering Manager will become Acting Engineering Manager.

One violation and one deviation were identified.

6. Exit Interview

The inspection scope and findings were summarized on August 4, 1995, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors. Dissenting comments were not received from the licensee.

Item Number	Status	Description/Reference Paragraph
LER 1-95-03	Closed	Failure to Maintain Emergency Diesel Generator Staggered Testing Requirements, paragraph 3.c.
324,325/95-15-01	Open	DEV, Poor Material Condition of Flood Doors, paragraph 5.
324,325/95-15-02	Open	VIO, Presence of NRC Inspector Communicated, paragraph 5.
324,325/95-15-03	Open	URI, Procedure for Storage of Material in Contaminated Areas, paragraph 5.

7. Acronyms and Initialisms

APRM	Average Power Range Monitors
ASSD	Alternate Safe Shutdown
BPV	Bypass Valve
CFR	Code of Federal Regulations
CP&L	Carolina Power and Light
CR	Condition Report
CRD	Control Rod Drive
CRDM	Control Rod Drive Mechanism
DEV	Deviation
DG	Diesel Generator
EHC	Electro-hydraulic Control
ERFIS	Emergency Response Facility Information System
E&RC	Environmental & Radiological Controls
ESR	Engineering Service Request
F	Fahrenheit
FSAR	Final Safety Analysis Report
GE	General Electric

GPM	Gallons Per Minute
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
I&C	Instrument and Controls
IFI	Inspector Followup Item
IR	Inspection Report
LER	Licensee Event Report
LL1	Low level One
LPU	Loss Prevention Unit
MCC	Motor Control Center
MSIV	Main Steam Isolation Valve
MSL	Mean Sea Level
NAD	Nuclear Assessment Department
NAS	Nuclear Assessment Section
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PES	Plant Evaluation Section
PMH	Probable Maximum Hurricane
PNSC	Plant Nuclear Safety Committee
PSIG	Pounds Per Square Inch Gauge
QC	Quality Control
RCIC	Reactor Core Isolation Cooling
RFPT	Reactor Feed Pump Turbine
RI	Resident Inspector
RTD	Resistance Temperature Detector
RWCU	Reactor Water Cleanup
SBGT	Standby Gas Treatment
SCBA	Self Contained Breathing Apparatus
SDC	Shut Down Cooling
SIIT	Site Incident Investigation Team
SRO	Senior Reactor Operator
SRI	Senior Resident Inspector
SRV	Safety Relief Valve
SW	Service Water
TS	Technical Specification
UFSAR	Updated FSAR
URI	Unresolved Item
VIO	Violation
WCC	Work Control Center
WR/JO	Work Request/Job Order