U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Carolina Power & Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	October 24 - December 4, 1999
Inspectors:	T. Easlick, Senior Resident Inspector E. Brown, Resident Inspector E. Guthrie, Resident Inspector J. Lenahan, Reactor Inspector (Sections E7.1, E8.1, and E8.2)
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Enclosure

EXECUTIVE SUMMARY

Brunswick Steam Electric Plant, Units 1 & 2
NRC Inspection Report 50-325/99-08, 50-324/99-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an engineering follow-up inspection by a regional inspector.

Operations

- The plant responded as designed to a loss of the 1B reactor feedwater pump turbine (RFPT) and the subsequent insertion of a manual scram due to lowering reactor water level. Operator response to this event was prompt and efficient, taking actions in advance of the automatic protective features (Section O1.1).

- The licensee's cold weather program ensures that freeze protection is maintained on safety-related and selected non-safety-related equipment, remote buildings, and instruments. Operators were knowledgeable of the program and the procedures provided instructions and check sheets if outside temperatures dropped below designated thresholds (Section O1.2).

- A violation with two examples was identified when it was determined that no proceduralized control programs existed for instructional aids in the form of hard cards and plant warning labels (Section O3.1).

Maintenance

- The inspectors identified a procedure violation while observing a clearance being hung on the Unit 1 high-pressure coolant injection system. Contrary to independent verification procedure requirements, a reactor operator positioned a component and independently verified the position of the same component with no valve position indication (Section M1.2).

- The licensee had satisfactorily established and documented a process for assessing the overall effect on the performance of key risk assessment factors before removal of systems, structures, or components from service. However, the training requirements for personnel who authorized emergent changes to the approved schedule did not assure that those personnel had obtained the formal training that would allow the proper consideration of key risk assessment factors. A pending procedural change that would have emergent schedule changes reviewed for risk significance by senior licensed personnel provided adequate confidence that the key risk assessment factors would be appropriately considered (Section M5.1).

Engineering

- During review of the RFPT trip and resulting scram that occurred on Unit 1 on November 5, the inspectors identified design evaluation and implementation deficiencies for major plant modifications. Specifically, for the Maximum Extended Operating Domain and Power Up-Rate modifications, the inspectors determined that continuing problems existed in both the implementation of the modifications as well as the review and evaluation of their impact on integrated plant operations (Section E2.1).

- The licensee's corrective actions were effective in resolving and correcting the Non-Cited Violations identified by the NRC during the safety system engineering inspection performed in January, 1999 (Section E7.1).

Plant Support

- A violation was identified for the licensee's failure to properly identify that a missing temperature switch affected the operability of the engine-driven fire pump and to promptly correct this condition. As a result of this failure, licensee personnel subsequently allowed the motor-driven fire pump to be removed from service for maintenance. With both pumps concurrently inoperable, the licensee's ability to mitigate a fire was degraded due to the unavailability of satisfactory means to provide water fire suppression (Section F8.1).

Report Details

Summary of Plant Status

Unit 1 began the report period operating at 100 percent rated thermal power (RTP). On October 26, power was reduced to 90 percent RTP as a result of the loss of a circulating water intake pump due to high differential pressure across the traveling screen. The unit was returned to 100 percent RTP later that same day. On November 5, a manual reactor scram was initiated from 100 percent RTP due to the loss of a reactor feedwater pump. Unit 1 was returned to 100 percent RTP on November 7. On November 8, power was reduced to 80 percent RTP for control rod position improvements and returned to 100 percent RTP on November 9. The unit remained at full power for the remainder of the inspection period.

Unit 2 began the report period operating at 100 percent RTP. On November 9, power was reduced to 60 percent RTP as a result of the loss of two circulating water intake pumps due to high differential pressure across the traveling screens. The unit was returned to 100 percent RTP on the same day, where it remained for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 Unit 1 Reactor Feedwater Pump Trip and Manual Scram

a. Inspection Scope (71707, 93702)

The inspectors responded to and reviewed a Unit 1 reactor scram following the loss of the 1B reactor feedwater pump turbine (RFPT).

b. Observations and Findings

On November 5, with Unit 1 operating at 100 percent RTP, the 1B RFPT tripped during the performance of the bi-weekly Periodic Test 0PT-37.2.1, Reactor Feed Pump Turbine Tests, Revision (Rev.) 14. Operators immediately reduced reactor recirculation (RR) flow to reduce reactor power, which was followed by an automatic reactor recirculation pump runback. The 1A RFPT increased to maximum speed in response to the decrease in reactor vessel water level but was unable to maintain level. The operators inserted a manual scram prior to reactor water level reaching the low level 1 trip setpoint. The high-pressure coolant injection (HPCI) system was manually started for reactor water level control but was not needed and subsequently tripped on high water level, as the 1A RFPT recovered level following the manual scram. All plant systems and group isolations responded as designed. Operators' response to the event was prompt and efficient, taking actions in advance of the automatic protective features. The event was reported to the NRC in accordance with 10 CFR 50.73 on December 6 and was discussed in Licensee Event Report (LER) 50-325/99-009-00.

The inspectors reviewed the licensee's post-event trip review report, including process plant computer transient traces and plots, and verified that the plant responded to the event within design parameters. The RFPT periodic test being performed when the turbine trip occurred was conducted to ensure that the solenoids and mechanical components of the trip system would operate properly when called upon during an overspeed condition. During the testing activities, a trip signal was generated inadvertently while an operator had the trip lockout control switch in the lockout position and the overspeed trip test pushbutton depressed. The licensee's root cause investigation concluded that the most likely cause of the trip signal was the operator not fully engaging the lockout control switch or an intermittent electrical malfunction of the RFPT overspeed lockout test circuit. The licensee's root cause investigation also discussed a concern with a change in the operational effects of a single RFPT trip. Specifically, the remaining RFPT did not supply sufficient flow to the reactor vessel in order to maintain level above the low level 1 scram setpoint. This issue is further discussed in Section E.2.1, Loss of One RFPT above the 100 Percent Rod Line, of this report.

During the next scheduled refueling outage, the licensee plans to remove and test the trip lockout control switch and perform additional testing on the associated overspeed test circuit. The licensee is also evaluating revising the test frequency from bi-weekly to quarterly and revising the test prerequisites to require performance of the test during more restrictive plant operating conditions, i.e., low power levels.

c. Conclusions

The plant responded as designed to a loss of the 1B RFPT and the subsequent insertion of a manual scram due to lowering reactor water level. Operator response to this event was prompt and efficient, taking actions in advance of the automatic protective features.

O1.2 Cold Weather Preparations (71707, 62707, 71714)

The inspectors reviewed the licensee's preparations and implementation of their cold weather program. The inspectors reviewed Operating Instruction 0OI-01.03, Section 5.4, Freeze Protection and Cold Weather Bill, Rev. 7; 0FPP-024, Freeze Protection of Fire Suppression System, Rev.11; and, 0PM-HT001, Preventive Maintenance on Plant Freeze Protection and Heat Tracing Systems, Rev. 7. The inspectors also assessed operator knowledge in this area and conducted a walkdown of selected heat trace systems. The inspectors determined that the cold weather program was being effectively implemented. Operators were knowledgeable of the program and the procedures provided instructions and check sheets if outside temperatures dropped below designated thresholds. The program ensures that freeze protection is maintained on safety-related and selected non-safety-related equipment, remote buildings, and instruments.

O3 Operations Procedures and Documentation

O3.1 Instructional Aids and Operating Procedures

a. Inspection Scope (71707,62707)

The inspectors reviewed instructional aids used by licensed operators in the control room to verify that they met regulatory requirements. The instructional aids reviewed included "hard cards", which were quick-reference handheld placards, and plant warning labels located on the control panels.

b. Observations and Findings

Hard Cards

On September 20, operators used a hard card entitled Emergency Equalization Around the MSIVs, to open the Unit 2 main steam isolation valves (MSIVs) following a Group I isolation of the MSIVs. Licensee management stated that their expectations were that all hard cards were to be used only in conjunction with the use of emergency operating procedures (EOP); however, on September 20, a condition for entry into EOPs did not exist. The use of the hard card on September 20 complicated recovery following the Group I isolation, which eventually led to a manual scram. A detailed description of this event can be found in NRC Inspection Report 50-325(324)/99-07, Section O1.1.

On October 5, the inspectors determined that the hard card discussed above was not in accordance with the relevant operating procedure. The inspectors noted that some of the steps on the hard card were not in the same sequence as those in the operating procedure. Additionally, the title and the wording of one of the steps on the hard card were not the same as the operating procedure. The inspectors reviewed the procedure which controlled instructional aids – Administrative Instruction, 0AI-097, Plant Labeling, Rev. 14 – and found that hard cards had no specified controls on their content or use. In addition, this procedure did not contain any requirements to perform revisions to hard cards. In effect, the hard card deviations from the operating procedures were not controlled, reviewed, or approved in accordance with any documented program requirements.

The inspectors discussed with the licensee the observed differences between the hard cards and the operating procedures and the lack of clear guidance on when to use them. The licensee agreed that the hard cards did not match the procedures and that they should. The licensee stated that the use of hard cards should have been for EOP actions only and that clear guidance and controls were needed. The inspectors noted that operator use of the cards as they were written had not caused any other significant plant problems during their use.

The licensee audited all of the hard cards, which totaled about 10 for each unit. Hard cards had been developed for the following operator activities:

- operation of HPCI
- operation of reactor core isolation cooling (RCIC)
- manipulation of control rod drive flow
- control of condensate and feedwater systems
- bypassing and opening of MSIVs
- use hydrogen and oxygen monitors
- Group 6 isolation verifications
- suppression pool cooling

Numerous errors were found on 9 of the 10 cards, including incorrect step sequences, missing verifications of automatic actions, and erroneous values on operational parameters. In response to these findings, the licensee planned to revise every card to ensure that they accurately reflected the operating procedures. Additionally, the plant labeling procedure was going to be enhanced to provide instructions on hard cards. The licensee plans to eventually incorporate the hard cards into their associated procedures. During review of hard card issues, the licensee also identified several procedural enhancements and incorporated them into the operating procedures

Plant Warning Labels

On October 22, the inspectors determined that multiple warning labels existed on the reactor control panels of which the contents did not agree with operating procedures. For example, the inspectors found that a reactor control panel warning label for the scram discharge volume (SDV) high water level trip bypass (instructional aid number W1/036) provided a warning to verify that the SDV vent valves were shut prior to bypassing the scram discharge volume high level trip. The inspectors determined this to be in conflict with the sequence described in 0EOP-01-LEP-02, Alternate Control Rod Insertion, Rev. 19. This procedure directed bypassing of the scram discharge volume high level trip *before* checking that the SDV vent valves were shut. Further inspection identified that the warning label was created as part of a licensee NRC committed action item for IE Bulletin 80-17, Failure of 76 of 185 Control Rods to Fully Insert During a Scram at a BWR. A licensee response letter dated September 21, 1987, (IER 87-29, Exit [87B0377]), stated that the licensee would provide a standing instruction and temporary caution tags on both units to instruct the control operator to verify closure of the SDV vent and drain valves prior to bypassing the SDV high level trip. The inspectors noted that the temporary caution tags described in the letter had been changed to a permanent warning label. According to IER 87-29, the temporary caution tags were to be removed when 0EOP-01-LEP-02 was revised. However, procedure 0EOP-01-LEP-02, Rev. 19 was never revised to comply with the regulatory compliance action item assignment of letter IER 87-29.

The inspectors reviewed other warning labels on the control panels and found that none were controlled by plant labeling procedures. For example, a warning label existed for the rod in-out notch switch which stated that a time delay must occur between selecting two different rods to prevent inadvertent rod movement. This warning was not found as a precaution and limitation in the reactor manual control system operating procedure. The licensee stated that warning labels in the plant would be reviewed and processed correctly and that the plant labeling procedure would be revised to include program control instructions for warning labels.

10 CFR 50, Appendix B, Criterion VI, Document Control, states that measures shall be established to control issuance of documents such as instructions, including changes thereto, which prescribe all activities affecting quality. These measures shall assure that documents, including changes, are reviewed for adequacy and approved for release by authorized personnel. Changes to documents shall be reviewed and approved. Contrary to the above, the licensee failed to establish controls for instructional aids in the form of both hard cards and warning labels regarding issuance, approvals, changes, and reviews, as determined on October 5 and October 22. The lack of control of instructional aids for the hard cards and the warning labels are two examples of a violation of 10 CFR 50, Appendix B, Criterion VI. This Severity Level IV violation is being treated as a non-cited violation (NCV), consistent with section VII.B.1 of the NRC Enforcement Policy. This violation is identified in the licensee's corrective action program as AR 00008891, Instructional Aids, and is identified as NCV 50-325(324)/99-08-01, Lack of Programmatic Controls for Instructional Aids. The significance of the hard card control issue was that no controls existed to ensure quality in issuance, review, and approval of instructions used to physically operate the plant. The significance of the plant warning label control issue was that regulatory committed action items were not taken and control panel labels did not agree with operating procedures.

c. Conclusions

A violation with two examples was identified when it was determined that no proceduralized control programs existed for instructional aids in the form of hard cards and plant warning labels.

O4 Operator Knowledge and Performance

O4.1 Outside Auxiliary Operator Daily Rounds (71707)

On December 3, the inspectors observed the common outside operator during the performance of Operating Instruction 0OI-03.4, Unit 0 Outside Auxiliary Operator Daily Check Sheets, Rev. 74. The inspectors noted that the operator was knowledgeable of the systems being checked and that system parameters were verified to be within tolerance. Any questions, issues, or alarms were communicated to the control room for resolution. The operator was aware of the requirements in the cold weather bill and verified the proper operation of heat tracing during his rounds. The inspectors noted the operator's concern for electrical safety when he questioned the arrangement of power cords for a temporary drain pump in the lower level of the emergency diesel generator building. The operator stated that he would verify that the arrangement was in accordance with the applicable administrative procedure and correct it if necessary.

O8 Miscellaneous Operations Issues (71707)

O8.1 (Closed) LER 50-325/1999-009-00: Unplanned Reactor Feed Pump Trip Results in Insertion of Manual Reactor Trip. This issue was reviewed by the inspectors as described in Sections O1.1 and E2.1 of this report.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Activities (61726, 62707)

The inspectors reviewed all or portions of the following surveillance tests:

- Periodic Test 0PT-10.1.1, RCIC System Operability Test, Rev. 78
- Special Procedure 2SP-98-242, Op Testing of E51-F022/F045 Per GL-89-10, Rev. 0

The inspectors attended a pre-job briefing that was comprehensive, covering all precautions and limitations and human error precursors. During the start of the RCIC turbine in 0PT-10.1.1, the operators unexpectedly received a RCIC high exhaust pressure annunciator, which instantaneously cleared. The operators received no other indication of high exhaust pressure and the senior control operator (SCO) and shift technical advisor began to review the system drawings and annunciator response procedure to determine the cause of the alarm. During the performance of 2SP-98-242, the turbine was restarted and the operators again received the high exhaust pressure annunciator and a RCIC turbine trip. At that point, the RCIC turbine was declared inoperable and the appropriate NRC notifications were made. Subsequent troubleshooting by the licensee identified a problem with the RCIC exhaust line check valve that was causing a momentary pressure spike in the exhaust line. The problem was corrected and the surveillance was completed satisfactorily. Operator response to an unexpected annunciator during surveillance testing was appropriate. In addition, effective supervisory oversight was present during the surveillance activities.

M1.2 Independent Verification Clearance Process

a. Inspection Scope (71707,62707)

On October 21, the inspectors observed the pre-job briefing and the hanging of a clearance for maintenance activities on the Unit 1 HPCI system.

b. Observations and Findings

The inspectors observed that one of the two auxiliary operators (AOs) performing the clearance process was briefed in the control room. The sequence of hanging the tags was discussed. The clearance required that tags be hung on motor-operated valves

(MOVs). Nuclear Generation Group Standard Procedure, OPS-NGGC-1301, Equipment Clearance, Rev. 3, states in Section 9.2.1, Administrative - Clearance Preparation and Restoration, that MOVs could be used as an isolation boundary after the valve was positioned for the clearance, its power supply was isolated and tagged, and the handwheel was tagged to indicate the valve position.

The inspectors observed the AO verify that the valve was shut by observing a green indicator light at the motor control center prior to turning the power supply breaker off. The operator hung the tag on the breaker and then hung a tag on the handwheel of the valve. The person second-verifying the clearance did not know how to verify the valve position because there was no power to the valve for valve position indication and the licensee's procedures did not allow using stem position, local position indications, or movement of the valve handwheel (due to concerns over possible seat damage). After the second operator discussed the problem with the unit SCO, a line was drawn through the signature block so that the reactor operator could independently verify that the valve was in the shut position. Plant Program procedure 0PLP-21, Independent Verification, Rev. 11, stated that independent verification was the act of checking a condition, such as component verification, separately from activities related to establishing the condition or component position. The reactor operator had positioned the valve to originally align the HPCI system for the maintenance and had initialed the clearance sheet as having done that. The reactor operator also initialed for the independent verification of the valve contrary to 0PLP-21.

The inspectors reviewed OPS-NGGC-1301, Equipment Clearance, and other documents associated with clearance control and found that no guidance was given to hang clearances on MOVs; the procedure only described restrictions for hanging these clearances. Because of this, the position of the valve could not be independently verified because there were no indications that could be used by procedure.

Technical Specification (TS) 5.4.1.a, requires that written procedures shall be established, implemented, and maintained covering activities which are recommended in Regulatory Guide 1.33, Appendix A, November 1972, for equipment control and tagging. On October 21, the licensee failed to properly implement the procedural requirements of 0PLP-21, Independent Verification, Rev. 11, during the hanging of an equipment clearance on an MOV (Clearance No. 1-99-01277). This Severity Level IV violation is being treated as an NCV, consistent with section VII.B.1 of the NRC Enforcement Policy. This violation is identified in the licensee's corrective action program as AR 99-00008892, Clearances on Motor Operated Valves, and is identified as NCV 50-325/99-08-02, Failure to Follow Independent Verification Procedure.

The licensee initiated a standing instruction to provide guidance on how to perform clearances on MOVs. The licensee stated that a procedure revision was in progress to OPS-NGGC-1301 that would provide guidance and controls for the clearance process on MOVs.

c. Conclusions

The inspectors identified a procedure violation while observing a clearance being hung on the Unit 1 HPCI system. Contrary to independent verification procedure requirements, a reactor operator positioned a component and independently verified the position of the same component with no valve position indication.

M5 Maintenance Staff Training and Qualifications

M5.1 Emergent Work (62707)

The inspectors reviewed the licensee's process for assessing the impact on overall plant safety functions for the removal of a structure, system, or component from service due to an emergent failure or recent change to the maintenance work plan of the day. The inspectors reviewed the requirements for emergent work provided in Administrative Procedure 0AP-25, BNP Integrated Scheduling, Rev. 7. Figure 3 to 0AP-25 was used to document changes to the schedule and was procedurally required to be reviewed by the work week manager or by the shift superintendent during backshift, weekends, or holidays.

The licensee had satisfactorily established and documented a process for assessing the overall effect on the performance of key risk assessment factors before removal of systems, structures, or components from service. However, the training requirements for personnel who authorized emergent changes to the approved schedule did not assure that those personnel had obtained the formal training that would allow the proper consideration of key risk assessment factors. A pending procedural change that would have emergent schedule changes reviewed for risk significance by senior licensed personnel provided adequate confidence that the key risk assessment factors would be appropriately considered.

III. Engineering

E1 Conduct of Engineering

E1.1 Temporary Modification to Electro-Hydraulic Control System (37551)

The inspectors reviewed an engineering service request (ESR) package for a temporary modification which disabled the Unit 1 main turbine high exhaust hood temperature switches, which trip at 225 degrees Fahrenheit (°F). The temporary modification was needed due to a steam leak and wet environment in the area under the low pressure turbine skirt where the switches were located. The failure of the A or B high exhaust hood temperature switch could cause a turbine trip. The licensee had previously identified a failed switch associated with the B exhaust hood vacuum pressure alarm as a result of the high-temperature, high-moisture environment. The B high exhaust hood temperature switch was located adjacent to this recently-failed switch. These temperature switches do not perform any safety-related function. Additionally, turbine exhaust hood overheating was primarily a concern during main turbine start-up and low-load operating conditions.

The package contained the requisite 10 CFR 50.59 safety evaluation and clear installation instructions for temporarily lifting of the leads associated with the temperature switches. The package was prepared in accordance with plant procedures and contained the appropriate approval signatures. The exhaust hood temperature alarm at 175°F was not affected by this temporary modification. As identified in the ESR, the annunciator procedure was revised to provide additional operator actions to trip the turbine if hood temperature could not be restored or maintained below 225°F. The inspectors verified that the revision was completed and that the annunciator windows were properly identified as having inputs disabled. Discussions with the operators indicated that they were familiar with the temporary modification as well as the revised annunciator procedure.

E2 Engineering Support of Facilities and Equipment

E2.1 Loss of One RFPT Operating Above the 100 Percent Rod Line

a. Inspection Scope (37551, 71707)

The inspectors reviewed a November 5 Unit 1 RFPT trip at 100 percent RTP that led to a reactor vessel level transient, which reached the reactor protection system setpoint for a reactor scram. The inspectors investigated the transient to determine the impact of plant operational design on plant response during the event.

b. Observations and Findings

During inspector observations following the scram, the operators stated that a reactor scram on low level had not been expected to occur as a result of the loss of one RFPT. The operators were not aware that operating above the 100 percent power-to-flow rod line could have resulted in a low reactor water level scram if a RFPT was lost. The unit had been operating at 107 percent rod line at the time of the event. Operations determined that they did not have a full understanding of the effect on plant operations while operating at rod lines above 100 percent. In 1991, a modification had been implemented on both units which allowed for expanded operating domains to enhance fuel cycle economics through the implementation of reactor vessel flow control changes and increased core flow coast-down capability. The modification was entitled maximum extended operating domain (MEOD), which implemented a maximum extended load line limit (MELLL) related to the power-to-flow operating map.

The inspectors reviewed the licensee's letter from the vendor of the MEOD modification entitled MEOD Extended Operating Concerns - Recirc Runback Setpoints, KFC-37-89, dated October 2, 1989. This letter discussed the operational concerns associated with operating the plant using MEOD. The letter included recommendations to improve plant operations, such as preventing a reactor scram on the loss of one RFPT while operating using MEOD at rod lines above approximately 105 percent. The letter stated that as a result of the implementation of this new operating domain, it was desirable to reduce the recirculation pump runback limits such that a low level scram due to a single feedwater pump trip can be avoided when operating above the rated load line. The letter stated that the power reduction necessary to prevent a low level scram is dependent upon a combination of parameters, the most important parameter being the runout flow of a single feedwater pump. Additionally, the letter recommended that the licensee reduce the post-runback reactor core flow/RR pump speed to as close to 45 percent core flow as possible.

The inspectors determined through a review of the MEOD modification package, Modification Number 90-011, that the licensee raised the RR operational limiter runback setting in 1991 to an equivalent of about 53 percent core flow under the operating conditions seen during the November 5 transient. The reactor vessel core flow prior to this change was slightly less than 45 percent core flow. The inspectors determined this adjustment to have been non-conservative in light of the MEOD modification. The inspectors noted that the modification document, KFC-37-89, stated that for minor changes in reactor vessel core flow, a significant change in RTP occurs, which causes the RFPT required output demand to increase proportionally with the power increase.

The inspectors determined that the above condition was exacerbated by the Power Up-Rate modification implemented on Unit 1 in March 1997 and Unit 2 in October 1997. The inspectors determined the Power Up-Rate modification to be a missed opportunity to thoroughly evaluate the overall effects of the modifications on plant operations. The Power Up-Rate vendor documents clearly indicated that the RR operational limiter runback setting should have been set as close to 45 percent core flow and that with a minimum core flow setting the RFPTs would have been overloaded due to MEOD operations. The vendor stated that the power ascension test program should have been used to accurately set the RR operational limiter as necessary. The licensee informed the inspectors that the RR operational limiter had not been reset since 1991.

Based on the MEOD modification, the Power Up-Rate modification, the Thermal Hydraulic Instability modification, and the November 5 transient that occurred with the loss of a RFPT, the inspectors questioned the licensee whether the RR operational limiter setpoint had been evaluated and set where the licensee wanted it to be. The licensee was reviewing the modifications listed above and setpoints associated with them at the close of the inspection period. The setpoint of the RR operational runback was not a reactor safety concern; however the inspectors questioned the licensee's control of design changes to the plant.

The inspectors reviewed the licensee's process that controls major modifications to determine whether an overview was required to determine the effects of modifications on overall integrated plant operation. The inspectors reviewed the ESR modification program and found that the program relied on a review committee comprised of multi-disciplined individuals to address the changes that the modification may cause to other structures, systems, or components. No specific guidance was provided by the ESR process. The inspectors determined that the lack of guidance in the modification process contributed to the problems that existed in the review and evaluation of the impact of major plant modifications and their effects on overall integrated plant operations. The ESR procedure had not been changed to provide guidance since the list of above modifications were implemented.

Additionally, no evidence of additions to procedure precautions or changes to the training program occurred based on the knowledge that was presented in the vendor documents that operating at rod lines above 105 percent with a loss of a RFPT would probably result in a scram. The licensee determined that the simulator had not been modified to account for operating the plant with the MEOD modification. Simulator modeling showed that the plant would stay on-line following an RFPT trip, up to a 118 percent rod line. All of the simulator event scenarios reinforced to the operator that the loss of one RFPT would not cause a lowering reactor vessel level and subsequent reactor scram. The inspectors reviewed the simulator modification program and found that the program established an individual to review documents and changes to the facility, based on what was determined to be important by the individual, for any effects on the simulator and initiate whatever needed to be accomplished as a result of the changes.

The above findings constitute additional examples of previously-documented licensee problems with the evaluation and implementation of major plant modifications. Specifically, in January 1999, the licensee received a violation on design control which stated that there was a failure to adequately review and evaluate the impact of the thermal hydraulic instability (THI) modification on plant operations. NRC Inspection Report 50-325(324)/99-01, Section O1.1, also documented two issues regarding the failure to adequately implement simulator training involving the THI modification.

c. Conclusions

During review of the RFPT trip and resulting scram that occurred on Unit 1 on November 5, the inspectors identified design evaluation and implementation deficiencies for major plant modifications. Specifically, for the MEOD and Power Up-Rate modifications, the inspectors determined that continuing problems existed in both the implementation of the modifications as well as the review and evaluation of their impact on integrated plant operations.

E7 Quality Assurance in Engineering Activities

E7.1 Corrective Action Program

a. Inspection Scope (92903)

The inspectors examined the disposition of Condition Reports (CRs) initiated by the licensee to address NCVs identified by NRC during the Safety System Engineering Inspection (SSEI) documented in NRC Inspection Report 50-325(324)/98-14.

b. Observations and Findings

The inspectors reviewed procedure CAP-NGGC-0200, Corrective Action Program, Revision 0. This procedure described the process for initiating and resolving CRs. This procedure was issued to specify the requirements for resolution of CRs using the newly developed Passport Action Tracking module. Action Requests (ARs) are assigned to responsible individuals by the Passport system to resolve and disposition CRs. The inspectors reviewed the corrective actions for the following CRs:

CR 99-00217, -00222 and -00276

These CRs were initiated to resolve NCV 50-325(324)/98-14-02, Inadequate Control of Design Activities. The inspectors reviewed corrective actions to disposition CR 99-00222. This included review of ESR 9900186 which was completed subsequent to the SSEI to address the potential for plugging of the minimum flow pathway due to the revised design of the HPCI minimum flow valve. The ESR concluded the revised design was adequate based on periodic testing which showed that unacceptable clogging of the valves had not occurred. The licensee reviewed the periodic surveillance minimum flow test data performed since the new valves had been installed in Units 1 and 2. The test data showed the Unit 2 valve flow rate had decreased 52 percent since the new valve had been installed. The licensee initiated work request/job order (WR/JO) 99-AFUG1 to clean the Unit 2 minimum flow valve (valve number 2-E41-F012). The inspectors also reviewed ESR 9900200 which was completed by the licensee to review other similar valve configurations for potential clogging. The inspectors reviewed the proposed corrective actions to resolve the NCV example associated with the deficiencies identified with the MOV heater sizing calculations. The licensee issued AR 00005640 to revise the MOV calculations which will be completed by June 2000 to incorporate several outstanding design changes. The corrective actions to disposition CR 99-00217 included revision of procedure 0PT-09.2, HPCI System Operability Test. The inspectors reviewed Revision 104 of 0PT-09.2, dated May 5, 1999, and verified that the licensee had corrected the test acceptance criteria to incorporate TS surveillance requirement 3.5.1.7.

CR 99-00149 and -00157

These CRs were initiated to resolve NCV 50-325(324)/98-14-03, Failure to Perform an Adequate 10 CFR 50.59 Safety Evaluation. The inspectors reviewed corrective actions completed to disposition CR 99-00149. These actions included revisions to the safety evaluations to correct the deficiencies identified during the SSEI and retraining of engineering personnel responsible for preparation and review of safety evaluations.

CR 99-00116

This CR was initiated as corrective action for NCV 50-325(324)/98-14-06, Failure to Revise Drawings to Incorporate Design Change Information. The failure to update the design drawings also affected some of the drawings in the Updated Final Safety Analysis Report (UFSAR). The licensee revised the UFSAR drawings. The inspectors reviewed

UFSAR change packages 99-051 and 99-053 and verified that the changes had been incorporated. Since the plant drawings were not relied upon for use as design information, the licensee decided to retain the drawings for historical purposes only. The status of the drawings (i.e., not maintained current) has been indicated in the licensee's document control system.

CR 99-00219

This CR was initiated as corrective action for NCV 50-325(324)/98-14-07, Failure to Update UFSAR. The inspectors reviewed UFSAR change packages which revised the UFSAR and corrected the UFSAR discrepancies identified during the SSEI. In addition, some additional discrepancies in the UFSAR were identified by licensee engineers during a review of the UFSAR which was conducted as part of the corrective action for CR 99-00219. These discrepancies had minor safety significance and were corrected.

c. Conclusions

The licensee's corrective actions were effective in resolving and correcting the NCVs identified by the NRC during the SSEI performed in January, 1999.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspection Followup Item (IFI) 50-325(324)/98-14-01: Evaluate Function of HC Coils in DC MOV Control Circuits Heater Sizing Calculations

Review of the control wiring diagrams for the 250 volt DC MOVs disclosed that holding coils (HCs) were shown to be wired in parallel with the motor commutator and armature field in the MOV control circuits. Licensee engineers were not able to provide any information on the function of these coils or how they affected the motor overload relay sizing calculations. The licensee initiated CR 99-00276 to document and disposition this issue. AR 0006043 was initiated to document the corrective actions necessary to resolve this issue. Licensee engineers contacted the vendor who was unable to provide any specific data on the resistance of the holding coils. The licensee initiated WR/JO 99-ABUP-1 to measure the resistance of the holding coils. The results of the measurements showed that the resistance of the holding coils were 3500 Ohms. Licensee engineers determined that the current drawn by the holding coils was insignificant due to the high resistance of the holding coils. Additional corrective actions to correct this problem were to revise procedure EGR-NGGC-0106, AC and DC Overcurrent Protection and Coordination, to specify that the effect of current drawn by auxiliary devices such as holding coils are considered in thermal overload relay/heater selection. The inspectors reviewed EGR-NGGC-106 and verified that this change had been incorporated into the procedure. Licensee engineers were in the process of revising two calculations (one for Unit 1 and one for Unit 2) to include the effect of the holding coils on the overload relay sizing.

E8.2 (Open) IFI 50-325(324)/98-14-05: HPCI/RCIC Steam Line Drain Valve Operation

This issue concerned the design of the HPCI and RCIC steam supply line drain pot valves. These valves are air-operated and close on loss of instrument air. The instrument air system is non-safety related and may not be available under all design basis accident conditions since it is not seismically supported. In cases when either HPCI or RCIC would be required to cycle on and off, the unavailability of instrument air would cause the drain pot valves to remain closed which could result in an accumulation of condensed water in the drain pots/steam supply lines. The licensee initiated CR 99-00271 to disposition this issue. The licensee performed an evaluation of this issue and determined that both systems, RCIC and HPCI, were operable in the present design configuration. The inspectors discussed the operability evaluations with licensee engineers. For the RCIC system, licensee engineers determined that this system would most likely be operated continuously for system design basis accident conditions. However, licensee engineers determined that the RCIC system can be cycled on and off, and restarted even if a loss of instrument air would occur which would cause the RCIC drain pot valves to remain closed. The licensee will issue an operating procedure, RCIC Start Up with Loss of Air, to address this condition.

The inspectors also performed a walk down inspection and examined the components for the HPCI drain pot valves. These components included the valves, instrumentation, the discharge piping from the drain pots, the drain pots, and control room instruments. Control room instrumentation included position indication for the drain pot valves, the condensate (water) level indication for the drain pots, and the "Hi" level alarm for the drain pots. The inspectors also examined control room instrumentation which provides indication for the instrument air system. Although for some design basis accidents the instrument air supply to the drain pot valves could be unavailable, the control room operators would be aware of this situation and also could monitor the water level in the drain pots. The licensee has not finalized long term corrective actions to resolve these issues. These include procedure changes for operation of the HPCI and RCIC systems, or changing the position of the drain pot valves by maintaining them in the open position. AR 00005647 was issued to document the corrective actions to resolve this issue. This item remains open pending NRC review of the licensee's long term corrective actions.

IV. Plant Support

F8 Miscellaneous Fire Protection Issues (71750, 71707, 90712)

F8.1 (Closed) Unresolved Item (URI) 50-325(324)/99-07-02: Fire Pump Concurrent Inoperability

On August 23, 1999, the inspectors discovered an entry in the operators' logs regarding the unsatisfactory performance of a fire pump periodic test. During the August 22 performance of the test, the engine-driven fire pump (EDFP) had been stopped by the operators as a result of antifreeze spraying from it. CR 99-2093, Diesel Fire Pump, was generated to document this condition. During the time the EDFP was inoperable, the licensee removed the redundant motor-driven fire pump (MDFP) from service. On

September 1, the licensee determined that removing the MDFP from service had rendered the water fire suppression system inoperable for a total of approximately 37 hours and that having both fire pumps unavailable constituted a condition outside of the fire protection design bases. A licensee review concluded that had a fire occurred in the most risk significant plant areas during the dual fire pump outage safe shutdown would not have been comprised. The inspectors reviewed the licensee's analysis and agreed with the licensee's conclusions. The licensee subsequently made a report to the NRC under 10 CFR 50.73 in regard to this condition.

Based on the inspectors' review, it was concluded that on August 9 the licensee failed to identify and correct a condition adverse to fire protection. The lack of integrity of the EDFP coolant system was not promptly identified and corrected, which subsequently resulted in the EDFP unknowingly being inoperable/not available for approximately 16 days. License Condition 2.B.6 for Units 1 and 2 states that Carolina Power & Light shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report, Section 9.5.1, Fire Protection Systems. Final Safety Analysis Report, Section 9.5.1, requires that the Fire Protection program comply with the intent of Appendix A of Branch Technical Position (BTP) APSCB 9.5-1. Position C.8 of Appendix A of BTP APSCB 9.5-1, requires that measures be established to assure that conditions adverse to fire protection are promptly identified, reported, and corrected. The failure to properly identify that the missing temperature switch affected the operability of the EDFP and to correct this condition is a violation. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1 of the NRC Enforcement Policy. This violation is described in the licensee's corrective action program as CR 99-2093, Diesel Fire Pump. This violation is identified as NCV 50-325(324)/99-08-03, Fire Pump Concurrent Inoperability.

V. Management Meetings

XI Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on December 13, 1999. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

A. Brittain, Security Manager
N. Gannon, Plant General Manager
J. Gawron, Nuclear Assessment Manager
K. Jury, Regulatory Affairs Manager
J. Keenan, Site Vice President
J. Lyash, Director of Site Operations
J. Franke, Brunswick Engineering Support Section Manager
W. Noll, Operations Manager
E. Quidley, Maintenance Manager
S. Rogers, Outage and Scheduling Manager

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71714:	Cold Weather Preparations
IP 71750:	Plant Support Activities
IP 90712:	Inoffice Review of Written Reports of Nonroutine Events
IP 92903:	Followup - Engineering
IP 93702:	Prompt Onsite Response To Events At Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-325(324)/99-08-01	NCV	Lack of Programmatic Controls for Instructional Aids (Section 03.1)
50-325/99-08-02	NCV	Failure to Follow Independent Verification Procedure (Section M1.2)
50-325(324)/99-08-03	NCV	Fire Pump Concurrent Inoperability (Section F8.1)

Closed

50-325(324)/99-08-01	NCV	Lack of Programmatic Controls for Instructional Aids (Section 03.1)
50-325(324)/98-14-01	IFI	Evaluate Function of HC Coils in DC MOV Control Circuits Heater Sizing Calculations (Paragraph E8.1)
50-325/99-08-02	NCV	Failure to Follow Independent Verification Procedure (Section M1.2)
50-325(324)/99-07-02	URI	Fire Pump Concurrent Inoperability (Section F8.1)
50-325(324)/99-08-03	NCV	Fire Pump Concurrent Inoperability (Section F8.1)

Discussed

50-325(324)/98-14-05	IFI	HPCI/RCIC Steam Line Drain Valve Operation (Paragraph E8.2)
50-325/1999-009-00	LER	Unplanned Reactor Feed Pump Trip Results in Insertion of Manual Reactor Trip (Section O8.1)