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

Report Nos.: 50-325/95-25 and 50-324/95-25

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

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: December 2, 1995 - January 6, 1996

Lead Inspector: J. B. Brady for 2/5/96
C. A. Patterson, Senior Resident Inspector Date Signed

Other Inspectors: P. M. Byron, Resident Inspector
M. T. Janus, Resident Inspector
J. J. Blake, Senior Project Manager, (Region II)

Approved By: M B Shymlock 2-5-96
M. B. Shymlock, Chief Date Signed
Reactor Projects Branch 4
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection included the areas of operations, maintenance and surveillance, engineering, and plant support. A demonstration of GE's Ultrasonic Examination Procedure detection and sizing capability for cracking in the area of the Reactor Vessel feedwater nozzle inner radius was also inspected.

Results:

In the Operations area, Unit 2 set a new boiling water reactor world record for continuous operation breaking the old record of 533 days, paragraph two. Operations improvements included the initiation of computerized operations logs and development of a conduct of operations manual.

In the Maintenance and Surveillance area, an unresolved item was identified concerning problems associated with a high pressure coolant system (HPCI) maintenance outage, paragraph three. The licensee has not determined whether the unsuccessful operability test was caused by a condition prior to the maintenance outage or the maintenance activities during the outage. The HPCI

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governor EGR was replaced and a failure analysis of the old one was planned. Also, the licensee identified that an incorrectly sized gasket was installed in a flanged joint. The licensee has been using probabilistic safety assessment for a variety of applications. The assessment has been kept current with the latest equipment unavailability data.

GE successfully demonstrated the capability to measure the depth of cracks originating on the inner radius of a BWR reactor vessel feedwater nozzle mockup.

In the Engineering area, an unresolved item was identified concerning the implementation of emergency diesel generator governor modification, paragraph four. The licensee attempted to install the modification a second time, during a seven day limiting condition for operation, but after unexpected system response during testing the old governor was reinstalled. This problem occurred despite implementation of corrective actions for two previous escalated enforcement items concerning design control and review by a consultant.

After completing repairs to various seals and ventilation ducting positive pressure was restored for the control room without compensatory measures. Additional corrective actions are planned by the licensee. The licensee has historically had problems with maintaining positive control room pressure and their TS only requires a slight positive pressure.

In the Plant Support area, the Plant Evaluation Section conducted an audit of the Nuclear Assessment Section and concluded that the Brunswick Section was not as probing into issues as the sections at the other two utility nuclear sites, paragraph five. The site management took exception to the number of findings. Site management regarded the large number of finding as an indication of relative effectiveness, but agreed that improvement was needed in communications, filling of vacancies, and providing more specific issues.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*W. Campbell, Vice President, Brunswick Nuclear Plant
G. Barnes, Manager, Training
E. Black, Level III Examiner, Nondestructive Examination
A. Brittain, Manager, Security
*N. Gannon, Manager, Maintenance
J. Gawron, Manager, Environmental & Radiological Control
R. Lopriore, General Plant Manager
*G. Gibbs, Manager, Brunswick Engineering Support Section
*G. Honma, Supervisor, Licensing
J. Langdon, Supervisor, Nondestructive Examination
*W. Levis, Director, Site Operations
*J. Lyash, Manager, Operations
D. Hicks, Manager, Regulatory Affairs
*J. Thompson, Acting Manager, Nuclear Assessment
M. Turkal, Supervisor, Regulatory Compliance

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

Other Organizations

B. Dummer, General Electric (GE) Inspection Services
E. Kietzman, Electric Power Research Institute (EPRI) NDE Center
D. MacDonald, EPRI NDE Center
S. Mortenson, GE Inspection Services
J. Romano, GE Inspection Services
T. Romano, GE Inspection Services
J. Self, Manager, GE Inspection Services

NRC Personnel

*C. Patterson, Senior Resident Inspector
P. Byron, Resident Inspector
*M. Janus, Resident Inspector
D. Naujock, Materials and Chemical Engineering Branch, Nuclear Reactor Research

*ATTENDED EXIT MEETING

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

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2. Operations

Operational Safety Verification (71707)

Unit Status

Unit 1 operated continuously during this inspection period and had been on-line 94 days.

Unit 2 operated continuously during this inspection period and had been on-line 552 days. A world record for continuous BWR operation was broken when the old record of 533 days was surpassed.

Feedwater Temperature Reduction

On December 12, 1995, during a routine tour of the control room the inspector reviewed the procedural limitations for the final feedwater temperature reduction in place for the Unit 2 power coastdown to the refueling outage. The inspector reviewed procedure 2SP-95-212, Final Feedwater Temperature Reduction and Pressure Set Adjustment. The inspector observed an operator using an expanded graph, to determine main steam flow versus throttle pressure to ensure that reactor steam dome pressure was within specification. Another operator observed that the expanded graph was not part of the procedure and had it removed from the control room. The correct graph was used to verify that the reactor steam dome had not exceeded any limits The licensee initiated CR 9502913 to document the use of the non-approved graph. The non-approved graph was determined to be accurate and was taken from the same data base as the figure in the procedure. The inspector discussed this issue with operations management. The inspector determined that the consequence of the non-approved graph was of minor consequence. The licensee promptly corrected the problem.

Operations Enhancements

Operations completed two initiatives to enhance performance. The first was to implement a computerized operator log system. The new computerized logs were more legible and had sorting options to enable review of all operator's logs for a certain time period. The new logs were carefully implemented using both hand written and computerized logs in parallel, until the new logs were verified to produce the desired results. Training on the new log keeping system was held for all the operators. The second initiative was the consolidation of various plant procedures into a conduct of operations manual. This concluded a comprehensive review of all operations procedures and practices to ensure consistency.

Heat Balance

On December 13, 1995, at 6:11 p.m., the licensee made a courtesy notification to the NRC Headquarters Operation Center. The notification concerned a non-conservative error of approximately 1.5 MWth, discovered in the calculation of the core thermal heat balance. The licensee identified the problem based on a review of industry reports pertaining to an NRC preliminary notification, of a similar problem reported at another BWR site. The licensee subsequently determined that approximately 8.5 gpm of CRD system flow was not accounted for in the thermal heat balance calculations provided by GE for Units 1 and 2. At the time of the report, the licensee was in the process of reviewing the original basis for the heat balance inputs to determine if this flow had been evaluated elsewhere in the calculation. In the interim, a Standing Order was issued to maintain shift average core thermal power 2 MWth lower than the maximum power level specified in the license.

On December 14, 1995, the licensee installed a software change to the process computer which modified the computer software calculation to account for the omitted CRD flow in the core thermal heat balance. Following this change, the licensee returned both units to full license thermal power operation. This problem had been identified at a number of other BWR sites.

No violations or deviations were identified.

3. Maintenance and Surveillance

Maintenance Observation (62703)

HPCI Problems

On December 20, 1995, the Unit 1 HPCI system was removed from service to perform a series of planned maintenance and modification activities. The major activities included: the repair of the oil filter selector valve; repair of a leaking oil filter housing cap; replacement of the remote local auxiliary oil pump selector switch; replacement of the Woodward Governor dropping resistor with an isolated power supply; and the removal of the temporary modification for ERFIS flow indication. Following the completion of these various work activities, post maintenance tests were performed to verify governor performance and to confirm that there were no oil leaks.

During the initial system start, HPCI turbine speed, flow and discharge pressure increased to values higher than normally expected during a normal PT system start. Following the initial spike in turbine speed, the turbine returned to the normal expected speed. However, the pump discharge flow element flange developed a substantial water leak, necessitating securing from the run. Following the run, the licensee initiated activities to correct the leak, and determine the cause of the abnormal turbine start.

As required by the PT following the shutdown of the HPCI system, the auxiliary oil pump was left running to provide cooling to the turbine bearings. In this configuration, the HPCI governor steam valve E-41-V9 should have remained open. It was identified that the governor valve was closed and subsequent troubleshooting revealed that the valve would not open. The system was declared inoperable, and a four hour 50.72 report was made for HPCI inoperability. The significance of the event was reported as minimal, since the ADS, Core Spray and LPCI systems were available and operable during the event. The SS conservatively reported the event even though the system was already out of service for maintenance activities prior to the event. It was not known if the problem existed prior to the maintenance activities, or was the result of them.

Troubleshooting activities were initiated for the three identified problem areas following the event, the abnormally high HPCI turbine speed, leaking flange, and the governor valve not opening. A review of computer traces for the run indicated that the governor steam valve was open when the stop valve started to open, thus causing the high turbine speed response seen during the test. This sequence was not normal for the opening of the stop and governor valves. During the normal sequence, the oil system porting initially pops the governor valve open, then as oil pressure drops due to porting elsewhere, the governor valve closes, following the closure of the governor valve, the stop valve opens. Once the stop valve opens beyond the full closed limit switch, the governor valve then slowly opens. During this overspeed start, all indications were that the governor valve was less than fully closed when the stop valve started to open. The licensee suspected that air entrained in the oil system from the earlier maintenance activities could have caused the valves to operate out of sequence.

The troubleshooting investigation into the stuck governor valve was a two step process, first electronic, then mechanical. The licensee investigated the electronics first, as the system response was indicative of a failure in the electronic governor controls. The entire electronic controls system for the HPCI turbine governor was inspected and verified to be operating properly. Finding no problems with the electronics, the licensee concentrated their efforts on possible mechanical causes. The first area investigated was the Woodward Governor EGR mechanism. The licensee verified that the electronic signals to the EGR were correct, thus the mechanical/hydraulic output was suspected. On removal of the EGR assembly, the licensee identified that the EGR shaft did not rotate freely. Following a review of the work and the problems found with the EGR, a new EGR assembly was pulled from stock, inspected and installed in the system. The governor and control valves were then tested numerous times to verify proper operation. The system was successfully tested and declared operable on December 22, 1995. The licensee plans to completely disassemble the EGR and identify the failure mode.

The investigation into the cause of the discharge flow orifice gasket failure indicated that a minor leak had been identified in June of 1995. A work ticket developed at that time also identified that the flange bolting studs were not the correct size specified for the flange. The undersize studs were evaluated for structural adequacy in ESR 95-1063. The investigation of the failed gasket indicated that the smaller studs resulted in a shifting of the gasket backing plate approximately 3/16 of an inch from the centerline. This resultant offset lead to the eventual failure of the spiral wound gasket material. During the gasket repair activities, the licensee replaced the undersized studs. All reviews of work history on the flange suggested that the under-sized studs may have been from original construction.

Following the flange repair and return to service, the licensee identified that an incorrect size gasket had been installed. The gasket installed was sized for a smaller flange assembly. The licensee identified this issue in CR 95-3024. Based on discussions with the gasket vendor, the licensee evaluated the use of this gasket in this application, and documented its justification in ESR 96-008. The ESR documented the system's operable with this gasket installed, but recommended remove and replacement of the gasket with the correct size gasket during the next system outage. The licensee was currently investigating the cause of this incorrect installation. Unit 2 has been inspected, and a similar gasket problem was identified. The work history indicated that this gasket was replaced 1986. ESR 96-008 also evaluated the continued use of this gasket on Unit 2 as acceptable. However, it will be replaced during the upcoming Unit 2 RFO.

The inspector followed the licensee's troubleshooting and repair activities during his event. The inspector noted that the troubleshooting plan was well developed and systematically planned to attack the most likely causes and proceeded until a problem was identified and successfully resolved. The inspector noted that the presence of the system engineer in the field during theses efforts greatly facilitated the speed at which these problems were identified and resolved. The inspector found the maintenance work crews involved in these activities to be very well prepared and knowledgeable of the activities at hand and system operation. The inspector concluded that the licensee conducted a well executed recovery of the system in a minimum amount of time.

Based on the continuing investigations in progress regarding the different issues associated with this event, this item will be tracked as Unresolved Item 325/95-25-01, HPCI System EGR and Gasket Problems.

Probabilistic Safety Assessment

On December 12, 1995, the inspector meet with a representative from the corporate PSA section to discuss the wallet size card concerning a PSA summary for Brunswick. One side of the card contained graphs showing the overall core damage frequency with contributions to CDF by initiating event type and sequence type. The other side of the card contained graphs of important systems by risk contribution and a listing of important operator actions.

The PSA was updated in October 1995, and an overall decrease in CDF from 1.1xE-5/year to 9.1xE-6/year was calculated. This was due to less plant challenges occurring. A significant contributor to this decrease was the modification of the feedwater control system to a digital system resulting in fewer feedwater transients. The updates are planned after each refueling outage.

A list of ten current applications of PSA at Brunswick were discussed. The items were maintenance rule, emergency planning, PSA training, severe accident management, generic letter 89-10 (MOVs), LER review, plant modification review, revised TS, graded ISI/IST, and emergent issues. In addition, the inspector reviewed procedure OPLP-24, Work Management Process, revision 13, dated October 30, 1995. This procedure was revised to incorporate PSA insights with respect to performing on-line system outages of selected Maintenance Rule risk significant systems. Contained in OPLP-24 are approval matrixes for system outages, twelve week rolling schedule, precautions for dominant accident types, and risk significant systems as identified by the maintenance rule.

The inspector concluded that the use of the PSA wallet size card was an effective learning tool for plant personnel. The licensee has been using PSA in a wide variety of applications. The PSA model has been kept current using equipment availability data.

Inservice Inspection (73753)

Feedwater Nozzle Examination

Ultrasonic Inspection Demonstration for NUREG 0619 Feedwater Nozzle Examination. In preparation for the ultrasonic inspection of the inner radius areas of the Brunswick Unit 2 feedwater nozzles, the licensee arranged a test of the GE capability of detection and sizing of cracks in the inner radius and bore areas of the feedwater nozzles using the GERIS 2000 ultrasonic inspection system. The demonstration was conducted at the GE Inspection Services facility in Huntersville, NC. (near Charlotte, NC)

Through testing and modelling, it has been determined that the most difficult area of the feedwater nozzle to inspect is the inner bore radius area at the three and nine o'clock locations. CP&L contracted to have thermal fatigue implants placed in a stainless steel clad feedwater nozzle mockup to simulate the configuration of the Brunswick Unit 2 Reactor Vessel. The implants were installed near the nine o'clock location, with one on the inner radius and one just inside the bore of the feedwater nozzle. The licensee also contracted to have EPRI oversee the process and to provide third-party review of the GE inspection of the mockup. At the time of the inspection, GE had completed the inspection and sizing of the implanted thermal fatigue cracks and was awaiting word from CP&L and EPRI as to how well they had sized the indications.

On the first day of the inspection, after discussions with the licensee, GE, and EPRI on the technical bases, etc., for the inspections, the inspector reviewed the inspection and sizing procedures; witnessed a partial inspection of the nozzle mockup; and reviewed data analysis and sizing techniques. The procedures involved were the following:

UT-BRU-703V1, Rev 0	Procedure for the GERIS 2000 OD Ultrasonic Examination of RPV Nozzle Inner Radius and Bore Regions.
UT-BRU-706V0, Rev 0 Draft	Procedure for RPV Flaw Sizing with the GERIS 2000 OD System
GE-ADM-1002, Rev 0	Procedure for Data Review and Analysis of Recorded Ultrasonic Indications

On the second day of the inspection, data records from the inspections witnessed on the previous day were analyzed, and the results compared with previously recorded inspection data.

The GE flaw-sizing inspection results were compared with the flaw sizes recorded by the contractor that installed the implants in the mockup. The crack depths recorded by GE compared very favorably with the measured implant depths. The results were noteworthy in that the crack-depth measurements included the portion of the crack that traversed the 1/4" stainless steel cladding on the inside of the mockup, and in one case, that 1/4" comprised almost two thirds of the depth of the crack.

Based on the inspection and sizing demonstration, the licensee concluded that using the GERIS 2000 inspection system, GE would be able to detect, and adequately size, significant crack indications in the inner radius of the feedwater nozzles at Brunswick. After comparing the dimensions of the Brunswick feedwater nozzles with the dimensions of the mockup, and comparing the ultrasonic models of the two nozzles, the EPRI representatives and the inspector agreed with the licensee.

No violations or deviations were identified.

4. Engineering

a. On Site Engineering (37551)

Management of Leaking Fuel

On December 8, 1995, Unit 2 commenced a downpower to approximately 25% power to perform a drywell entry to add oil to the recirculation pump motor. The licensee took advantage of this downpower to take further action to cope with known fuel rod leakers for the remainder of the cycle coastdown. While at the reduced power levels, the licensee inserted two additional control rods in the areas of the suspected leakers. The licensee had previously inserted two control rods in these areas. The insertion of the additional rods would serve to further suppress the flux in the area, thus helping to mitigate the fuel rod leakage.

Additionally, the licensee was monitoring the offgas activity as an indication of the effectiveness of these suppression activities. Following the suppression efforts, the offgas activity started to trend down until it stabilized around 7500 microcuries/sec. The offgas activity prior to the insertion of the additional control rods was approximately 8900 microcuries/sec. The licensee expects to see a slight increase in the trend through the remainder of the cycle. However, no additional suppression activities are planned for the remainder of the coastdown. These activities, as well as, outage and post outage investigation activities were discussed with the appropriate Region II personnel and the inspector during a teleconference held on December 14, 1995. The regional personnel did not identify any concerns at the time, however, they expressed an interest in the licensee's efforts to identify the mechanism for the fuel failure. The inspectors will continue to monitor the licensee's efforts to resolve this issue.

Diesel Generator Governor Modification

On December 4, 1995, the licensee attempted to implement for a second time, plant modification 94-17, Replacement of the EDG Woodward Governors on DG 1. The plant modification replaces the existing Woodward governor with a newer model governor.

Problems were first experienced with the attempted modification of DG 4 during governor response testing on October 16, 1995. These problems and the event scenario were documented in NRC Inspection Report 95-22. Component malfunctions were eliminated as a possible source of the October problems following a complete diagnostic testing and evaluation of the governor components by the manufacturer (Woodward). The licensee did not recognize that engine inertia while slowing down dictated the response rather than the governor under certain unloaded test conditions. The licensee extensively reviewed past problems and prepared to perform this process again on DG 1.

On December 4, 1995, DG 1 was declared inoperable and the units entered a seven day LCO to support the installation of the governor modification. The installation process was well controlled and conducted in accordance with a well developed implementation plan including contingency plans to reinstall the existing governor should testing be unsuccessful. The inspector reviewed the work in progress and found the technicians involved to be knowledgeable and proficient at their respective jobs. The installation work was completed ahead of schedule, and the licensee was ready to start the acceptance testing on December 5.

Acceptance testing of the DG governor modification was controlled by Special Test Procedure 1-SP-PM9417-02, PM 94-017, Acceptance Test Emergency Diesel Generator #1. This special procedure was developed to functionally verify the changes implemented by the modification to the DG. The test functionally verified the capability of the DG to quickly recover from a sudden load addition greater than the single largest emergency load, while maintaining frequency within indicated range. The test also verified the capability of the DG to reject a load larger than the TS required load without tripping on overspeed. Additional tests verified that the DG equipped with the new governor meet the same performance specifications as required by the original factory and pre-operational testing.

The initial portions of the acceptance testing involved component and wire installation verification. This component verification was followed by final tuning of the governor and verifying unloaded engine responses. Successful completion of these tests lead to the performance of the actual loaded performance portions of the test procedure. On December 5, both units entered an 8 hour LCO due to emergency bus E-1 being aligned to DG 1 for testing purposes. DG 1 was started and was prepared to accept a core spray pump and CRD pump being simultaneously loaded, a load in excess of the largest emergency load.

Unit 1 experienced a half scram due to the loss of RPS A, which was powered from emergency bus E-1. The EPA breakers for RPS A tripped on under frequency when the emergency bus frequency dropped to 55.95 Hz when DG 1 was loaded. The DG was unable to meet the acceptance criteria for this portion of the test, maintain bus frequency above 57 Hz and recover to greater than 58.8 Hz within 2 seconds of being loaded. The inability of the DG to recovery bus frequency after being loaded resulted in the loss of RPS A on under frequency. The possibility of this under frequency bus transient had been covered in the procedure precautions and covered fully in the pre-job brief. Following the recovery of affected systems, RPS A was realigned to be powered from its alternate power source for the remainder of the DG testing. DG testing was stopped and the event and results were reviewed.

Following a review of test results, the licensee determined that the governor needed to be adjusted further to increase its response time in order to meet the acceptance criteria. The governor was tuned to the outer band of stable control, which should have resulted in the greatest improvement in response time. The same load addition test was performed, yielding nearly identical results. The DG was shutdown, and the testing was put on hold again while the test results were reviewed.

A conference call was held with Woodward to discuss the governor response and test procedures. Woodward could find no problems with the governor response, instead, they determined that the load being applied was too great for the DG to pick up and meet the specified acceptance criteria. Woodward suggested attempting an additional run with the same tuning parameters as the first run, but with a smaller load. Based on this information, the licensee initiated a re-review of the acceptance test and the basis for the loads chosen.

During the subsequent review of the test load, it was determined that the load required by the test was different from the largest single load applied during the 18 month MST. The load applied in the SP was determined based on the largest single ECCS load and then adding some excess load, the smallest 4160 volt load available to provide the extra margin. The 18 month MST applies the core spray pump and 2 sets of Drywell Chiller Fans. The differences in the two loads were discussed, but no one could provide a good explanation as to why the SP loaded run was significantly different from the 18 month surveillance run.

Later, the inspector questioned why the 18 month MST was not performed as part of the acceptance test, since it was designed to demonstrate DG system operability. The inspector was informed that the 18 month MST was performed only during an outage, when the actual full emergency-bus load and load reject sequences can be supported. This lead the inspector to question why the work was not performed during a outage when the 18 month MST could be performed. The inspector was informed that the work was done as an online activity due to the desire to complete a more timely replacement of the governor. The plant and engineering managers discussed this with the system and test engineers, and questioned the actual FSAR requirements.

The SP was revised to start two sets of Drywell Chiller Fans. The test was approved and performed on December 7, 1995. The test results using the modified SP loads were similar to the results of the two previous attempts. The governor failed to meet the response criteria for minimum bus frequency of greater than or equal to 57 Hz. Testing was secured, the DG was shutdown, and clearances were prepared in accordance with the contingency plan to remove the new governor system and reinstall the pre-existing governor system.

Prior to declaring the DG operable, a series of diagnostic tests were performed to verify that no damage had occurred to the DG as a result of the additional load testing. All tested parameters indicated no change in DG performance from the last 18 month monitored run performed on May 11, 1995. The DG was tested and declared operable on December 8, 1995, following a review of all test data by the PNSC.

After declaring DG 1 operable, the licensee began to scrutinize the design of the DG Governor Modification package and testing requirements. The license was performing this review independently of the engineers involved, through assistance from Corporate Engineering. An additional investigation and review was being performed by an outside DG specialist. The in house review of the governor modification design has preliminarily identified that the governor modification does not have the same capabilities as the previous governor. The new governor circuitry does not include a Load Pulse circuit, which was included in the design of the original governor. This circuit provides an anticipatory step jump in response to a step load increase, thus providing faster governor response. The differences in governor response between the two circuit designs has been confirmed by Woodward. The licensee continues to investigate how this feature was dropped during the modification design review. The licensee was continuing to investigate this issue. Pending the results of all the licensee investigations, this item was identified as URI 324,325/95-25-02, Inadequacies in DG Governor Modification.

This problem was an example of the continuing difficulty the licensee had in performing quality modifications on risk significant systems. The licensee had previously implemented a number of corrective actions for two previous Escalated Enforcement Actions related to design control (NRC Inspection Reports 95-14 and 95-20). These corrective actions included the formation of design and product review teams and affirmation process prior to release for work. As demonstrated by the second failed attempt to perform this modification, these corrective actions were not effective for this design product.

b. Followup - Engineering (92903)

(Open) URI 325,324/95-22-02, Control Building Ventilation Problems.

On December 4, 1995, the Control Building Ventilation System was declared operable based on the successful completion of OPT-46.4, Control Building HVAC Auto Initiation. The licensee was able to obtain a positive pressure in the control room with the CBEAF in the radiation/smoke mode. Condition Report 95-02591 was issued to track the cause of the negative pressure in the control room. Extensive engineering effort and testing were expended to determine the cause of the problem. The licensee was not able to determine the root cause of the event. Their investigation revealed that a large number of cable and door seals had deteriorated and duct work had degraded. Repairs in these areas enabled them to obtain a positive control room pressure. The licensee had successfully performed OPT-46.4 in November 1994. After that performance, modifications were made to the battery room ventilation systems for both units. This work was performed by PM 92051 (WO 93-AQWA1) and PM 92052 (WO 93-ABUP1) for Units 1 and 2 respectively. The licensee determined that these modifications had no effect on control room pressure.

The inspectors reviewed PMs 92051 and 92052 and noted that the licensee addressed the effects of the modification on the adjacent cable spread room but not on the control room. OPT-46.4 was not performed after the modifications to determine the overall effect on control room pressure. The battery rooms were designed to maintain a negative pressure and there was significant communication with the cable spread room. It appears to the inspectors that there was adequate information available to have caused the designer to consider the effects of the modification on the control room. The inspector discussed this observation with licensee management who plans to incorporate this in their corrective actions for improved engineering performance.

The inspectors reviewed historical correspondence and determined that on March 2, 1983, the licensee committed to a positive 1/8 inch of water pressure in the control room with the CBEAF in the radiation/smoke mode. The licensee performed additional evaluations and concluded that with the ventilation configuration that they could not achieve a positive 1/8 inch of water pressure in the control room. The licensee recalculated the dose rates to operators with a positive pressure in the control room and a 3000 SCFM inleakage penalty, and concluded that GDC-19 limits were being met. On August 30, 1985, the licensee submitted this evaluation to the NRC. On February 16, 1989, an SER was issued concurring with the licensee's conclusions.

LERs 1-95-20 and 1-95-20,Supplement 1 were issued to report this event to the NRC. Supplement 1 additionally reported that the licensee had not timed the closure of emergency recirculation damper (2J-D-CB) since March 19, 1993. The damper functioned as required, but the licensee did not time the closure as required by the procedure. The licensee identified this deficiency while performing OPT-46.4 on December 3, 1995. Subsequent timing test revealed that the damper met the timing requirements. The inspectors noted that the licensee committed in the LER to perform an SSFI of the Control Building HVAC system by June 30, 1996.

The corrective actions identified in CR 95-02591 were:

* Conduct SSFI of Control Building HVAC
* The development and implementation of a plan to establish periodic functional testing of the Control Building HVAC system and components.

* The development and implementation of a preventative maintenance route to evaluate and repair all control building access door seals on the 23 foot and 49 foot elevations.

The licensee plans to have the last two items completed by May 15, 1996. The licensee stated in the summary of the CR that there was no conclusive evidence to identify a root cause for the negative control room pressure. The inspectors noted that the licensee repaired the degraded door seals on the 23 foot and 49 foot elevations and were able to obtain a positive control room pressure. They also did not have a preventative maintenance program for the door seals. A contributor could be that the root cause for the negative control room pressure was the lack of a preventative maintenance program for door seals. The inspector has discussed this with the licensee. They acknowledged that their root causes do not always define actions to prevent recurrence.

The inspectors noted that the CR summary discussed the most likely contributing factor to the degradation may have occurred on July 13, 1995, when a tornado exhaust damper closed unexpectedly. This was not discussed in the LER. This event occurred just prior to a Unit 1 reactor scram when the licensee was pulling cables in a control room panel and possibly bumped a relay. The tornado damper closed suddenly causing an unusually high positive pressure in the control room. Operations reported doors were extremely hard to open, wet muggy odors, and ears popping due to pressure changes. After the initial shock wave, this pressure existed until the damper was repositioned several hours later. This event and the battery room ventilation modification both occurred after the last successful test conducted in November 1994. Either of these events could potentially cause the inability to achieve positive control room pressure. This item will remain open.

No violations or deviations were identified.

5. Plant Support (71750)

Nuclear Assessment Section

The licensee has two assessment organizations. NAS which is located at each of the three sites and reports to the site VP. PES which is an NGG function and has one representative at each unit who report to a manager in Raleigh. PES recently performed an assessment of the three NAS organizations and the results were contained in Report No. 95-15-QA-C (PES-95-124), dated November 15, 1995. The assessment identified that the Brunswick NAS was not considered to be sufficiently probing into potential issues. Each of the NAS organizations performed the same number of assessments but Brunswick NAS identified 26 issues and weaknesses while the other sites each identified 40. Brunswick NAS has not consistently provided substantive, value-added issues to line management. PES also identified that the Brunswick NAS was understaffed, key positions were either not filled or filled as an acting position, inadequate staff rotation, and was not included in site management discussions of key issues. These are not new issues. The inspector has previously identified that NAS assessments were not of sufficient depth and issues identified were not substantive. The PES findings indicate that NAS had not adequately addressed previously identified weaknesses. On December 4, 1995, the site VP provided a response to the Executive VP, NGG which addressed each issue identified by PES. The reply did not agree with the number of findings as indications of the quality of NAS work, but acknowledged areas for improvement.

The inspectors reviewed NAS assessment B-ES-95-01, dated December 1, 1995, of BESS. The assessment team determined that BESS was effective in support of the operation of BNP. They identified two issues: inadequate time allocated to perform a step in the station blackout procedure (AOP36.2) and pending FSAR changes were not routinely included in the safety review. This assessment did not identify any issues similar to those recently identified by the inspector or have been self revealing.

No violations or deviations were identified.

6. Exit Interview

The inspection scope and findings were summarized on January 5, 1996, 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.

On December 5 & 6, 1995, regional inspector, Jerome Blake, accompanied by Don Naujock of NRR, conducted an inspection of the CP&L sponsored demonstration of GE's ultrasonic examination procedure for the inspection of the Reactor Vessel feedwater nozzle inner radius area. The inspector was satisfied that the demonstrated GE procedure, personnel and inspection system are capable of detecting and depth-sizing fatigue cracks like those implanted in the mock-up. There were no violations or unresolved items from this part of the inspection.

Item Number	Status	Description/Reference Paragraph
325/95-25-01	Open	URI, HPCI System EGR and Gasket Problems, paragraph three.
324/325 95-25-02	Open	URI, Inadequacies in DG Governor Modification, paragraph three.

8. Acronyms and Initialisms

ADS	Automatic Depressurization System
BESS	Brunswick Engineering Support Section
BNP	Brunswick Nuclear Plant
BWR	Boiling Water Reactor
CBEAF	Control Building Emergency Air Filter
CDF	Core Damage Frequency
CR	Condition Report
CRD	Control Rod Drive
DG	Diesel Generator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ERFIS	Emergency Response Facility Information System
EPA	Electric Protection Assembly
EPRI	Electric Power Research Institute
ESR	Engineering Service Request
FSAR	Final Safety Analysis Report
GDC	General Design Criteria
GE	General Electric
gpm	Gallons Per Minute
HP	Horsepower
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
Hz	Hertz
ISI	Inservice Inspection
IST	Inservice Testing
LER	Licensee Event Report
LCO	Limiting condition for Operation
LPCI	Low Pressure Coolant Injection
MOV	Motor Operated Valve
MST	Maintenance Surveillance Test
MWth	Mega Watts thermal
NAS	Nuclear Assessment Section
NGG	Nuclear Generation Group
NRC	Nuclear Regulatory Commission
OD	Outside Diameter
PES	Performance Evaluation Section
PLP	Plant Program Procedure
PM	Plant Modification
PNSC	Plant Nuclear Safety Committee
PSA	Probabilistic Safety Assessment
PT	Periodic Test
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SCFM	Standard Cubic Feet per Minute
SE	Safety Evaluation
SP	Special Procedure

SS	Shift Supervisor
SSFI	Safety System Functional Inspection
TS	Technical Specifications
URI	Unresolved Item
VP	Vice President
WO	Work Order