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

Report Nos.: 50-325/89-44 and 50-324/89-44

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 1, 1989 - January 5, 1990

Inspectors: H C Dance / for 1/31/90
W. H. Ruland Date Signed

H C Dance / for 1/31/90
W. Levis Date Signed

H C Dance / for 1/31/90
D. J. Nelson Date Signed

Approved by: H C Dance 1/31/90
H. C. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of maintenance observation, surveillance observation, operational safety verification, onsite Licensee Event Reports (LER) review, in-office Licensee Event Reports review, facility modifications - Unit 2, Fitness For Duty - inspection of initial training programs, response to events - Unit 2 Alert, Emergency Diesel Generator No. 1 engine driven jacket water pump failures, action on previous inspection findings, cold weather preparations, TMI Action Item II.E.4.2.7 - Containment Isolation on High Radiation Signal, and installation and testing of modifications - Unit 2.

Results:

In the areas inspected, two violations and no deviations were identified.

One violation occurred when a licensed operator failed to consult plant drawings while researching a clearance, inadvertently causing a safety system to be inoperable for a short time. The applicable administrative procedure specifically required drawing research (paragraph 4.b).

The second violation occurred when the licensee supplied the NRC with inaccurate information in response to a Notice of Violation. The response stated that a computer database had been changed, contrary to what the inspector found (paragraph 11.c).

The inspectors found the licensee's Fitness For Duty training generally adequate. However, no mention was clearly made concerning illegal use of legal drugs during worker training (paragraph 8).

Two failures of engine driven jacket water pumps on diesel generator No. 1 occurred, most likely due to faulty shaft machining. Subsequent actions by plant management had an inadequate technical basis (paragraph 10).

The licensee continues to review the effect of possible fire protection sprinkler actuation during a high energy line break in the reactor building on plant equipment. The licensee's actions were appropriate (paragraph 11.a).

The licensee's preparations for cold weather complied with their procedures. Additional actions were taken for diesel fuel oil in above-ground tanks in response to inspector questions. These actions showed responsiveness to NRC concerns but a lack of self-critical look at their own operations (paragraph 12).

The licensee committed to revise their response to a TMI action item when the inspector found that an installed fuse and relay were not as described (paragraph 13).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Altman, Manager - Engineering Projects
*F. Blackmon, Manager - Operations
*S. Callis, On-Site Licensing Engineer
T. Cantebury, Manager - Unit 1 Mechanical Maintenance
G Cheatham, Manager - Environmental & Radiation Control
M. Ciemnicki, Security
R. Creech, Manager - Unit 2 I&C Maintenance
W. Dorman, Manager - QA
*R. Godley, Senior Reactor Operator
V. Grouse, Employee Relations
*J. Harness, General Manager - Brunswick Nuclear Project
W. Hatcher, Supervisor - Security
A. Hegler, Supervisor - Radwaste/Fire Protection
*R. Helme, Manager - Technical Support
J. Holder, Manager - Outage Management & Modifications (OM&M)
*L. Jones, Manager - Quality Assurance (QA)/Quality Control (QC)
*M. Jones, Manager - On-Site Nuclear Safety - BSEP
R. Kitchen, Manager - Unit 2 Mechanical Maintenance
*D. LaBelle, Shift Operating Supervisor
*J. Moyer, Technical Assistant to General Manager
*P. Musser, Manager - Maintenance Staff
*J. O'Sullivan, Manager - Training
*R. Poulk, Supervisor - Regulatory Compliance
*W. Simpson, Manager - Site Planning and Control
S. Smith, Manager - Unit 1 I&C Maintenance
*R. Starkey, Vice President - Brunswick Nuclear Project
R. Warden, Manager - Maintenance
B. Wilson, Manager - Nuclear Systems Engineering
*L. Wright, Corporate Quality Assurance

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

NRC Employees

*J. Milhoan, Deputy Regional Administrator

*Attended the exit interview

Note: Acronyms and abbreviations used in the report are listed in the last paragraph.

2. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance. The inspectors observed/reviewed portions of the following maintenance activities:

89-AIGM1	2A SLC Pump - Repair of Valve/Disc Seating Surfaces.
89-BBNM1	2B RPS MG Set - Repair of Failed Relay.
89-BCFE1	RCIC 1-E51-F045 - Troubleshoot/Repair of Valve Actuator.

Violations or deviations were not identified.

3. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

1 MST-RCIC22M	RCIC Steamline Low Pressure Instrument Channel Calibration.
1 MST-RCIC23M	RCIC Turbine Exhaust Diaphram High Pressure Instrument Channel Calibration.
1 MST-RHR22M	RHR-LPCI ADS CS Low Level 3, HPCI-RCIC Low Level 2 Division 1 Trip Unit Channel Calibration.
2 PT-6.1	SLC System Operability Test.

Violations or deviations were not identified.

4. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the technical specifications were met. Control operator, shift supervisor, clearance, STA, daily and standing instructions, and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specifications Limiting Conditions for Operations. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that continuity of system status was maintained. The inspectors verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was no leakage of major components; there was proper lubrication and cooling water available; and a condition did not exist which might prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspectors verified that the licensee's health physics policies/procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, posting, and instrument calibration.

The inspectors verified that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the protected area; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to alarms was adequate.

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

a. Inadequate Clearance Research

The licensee failed to follow AI-58, Revision 30, Equipment Clearance Procedure, while researching a RCIC equipment clearance. On January 2, 1990, while writing RCIC clearance 1-002 for work on the 1-E51-F025 (Steam Supply Drain Pot Drain Valve), the SRO in the clearance center required that circuit 2 in 125V DC distribution panel 3A be open. Not only did this deenergize the E51-F025 as anticipated, but also deenergized the HPCI flow inverter and flow controller. This action had rendered HPCI inoperable (unintentional). An annunciator alerted the operators to the problem at 3:42 p.m., and they reenergized the circuit two minutes later. For that short time, HPCI and RCIC were inoperable, placing the plant under the requirements of TS 3.0.3.

Interviews with plant personnel after the event revealed that the personnel who prepared the clearance consulted the RCIC operating procedure, 1-OP-16, Revision 19. That procedure did not indicate that the HPCI flow controller also received its power from Panel 3A, circuit 2. Further, the operator failed to consult plant drawings to determine the clearance's effect on the equipment. Had the operations staff examined drawing LL-30023, SH 6, Revision 22, they would have read that circuit 2 supplied power to the E11-Meter CKT (RHR), E51-VLV (RCIC) and E41-Control & Valves (HPCI).

The note after step 5.3.3.8 in AI-58 states that, "It is mandatory that a thorough research of the plant drawings be completed for the purpose of determining the clearance's affect on plant equipment prior to performing the next step."

Since the operators failed to perform a thorough research of plant drawings, this event is considered a Violation: Failure to Follow AI-58 for Drawing Research, (325/89-44-01). This clearance violation, while not identical to past clearance problems, continues a pattern of past poor performance regarding clearance preparation. The first violation issued in report 89-26 was the <u>second</u> example of a clearance violation regarding preparation, making the above violation the third example. While the licensee has submitted a supplementary response to the <u>first</u> example (see response dated January 2, 1990, for report 89-20), that details the results of a programmatic review, all licensee corrective actions have not yet been completed.

Listing of LERs with clearance problems.

<u>LERs</u>

1-88-01
1-88-29
1-88-34 (Civil Penalty)
1-89-04
1-89-07
1-89-08 (NCV)
1-89-15
2-89-15
2-89-16

Other problems not reportable or cited have occurred.

b. Battery Circuit Breaker in Off Position for Diesel Driven Fire Pump

On December 18, 1989, the inspector found the battery 1 circuit breaker in the off position for the diesel driven fire pump. The required position of the breaker is on as shown on page 137 of OP-41. When informed of the condition, the licensee placed the breaker in the on position.

The diesel fire pump start circuit receives power from redundant batteries. In the event that one of the two batteries is unavailable, the remaining battery will provide the necessary power for the start circuit. In this case, the circuit breaker for battery 2 was on. Thus, the diesel fire pump was operable with one of the two battery circuit breakers open. The licensee also demonstrated the operability of the fire pump by starting it under these same conditions.

The licensee initiated CATQ 89-006R to investigate the cause of the mispositioned breaker and to determine the necessary corrective action to prevent recurrence. The licensee believes that the breaker was accidently bumped during the performance of PT-34.1.1.0, Fire Pump Test, which had been performed the previous day. The reset switch to clear alarms received during the test is located next to the battery circuit breaker switches. The breaker switches are also very sensitive to the touch.

The licensee is considering some procedural changes to require the verification of the circuit breaker switch position following the performance of fire protection PTs which could affect the switches. In addition, more detailed instructions may be provided for the DSR performed by the fire protection AO. The inspector will monitor the corrective actions taken and their implementation in future routine inspections.

One violation and no deviations were identified.

5. Onsite Review of Licensee Event Reports (92700)

The below listed LER was reviewed to verify that the information provided met NRC reporting requirements. The verification included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of the event. Onsite inspections were performed and concluded that necessary corrective actions have been taken in accordance with existing requirements, license conditions and commitments.

(CLOSED) LER 1-87-10, Reactor Protection System Actuation While Attempting to Withdraw a Control Rod and While Attempting to Reset Initial RPS Actuation. The inspector reviewed the LER and the licensee's corrective action to prevent recurrence. The licensee installed a modification based on a study conducted by General Electric in each unit to reduce the amount of electronic noise induced into the SRM and IRM circuitry. The modification involved the installation of spike suppressor networks in parallel with rod select relays and CRD stabilizer valves along with the replacement of the grounding straps in the IRM and SRM drawers. In addition, the licensee provided training for the operations personnel on the event and revised plant annunciator procedures to provide additional checks by the CO prior to restoring the Scram Discharge Volume (SDV) high level trip function. The inspector had no further questions on this event.

Violations or deviations were not identified.

6. In Office Licensee Event Report Review (90712)

The below listed LERs were reviewed to verify that the information provided met NRC reporting requirements. The verification included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of the event.

(CLOSED) LER 1-89-22, Automatic Isolation of Units 1 and 2 Common Control Building Heating, Ventilating, Air Conditioning System and Emergency Air Filtration System.

(CLOSED) LER 2-89-18, Failure of Four Unit 2 SRVs to Meet Technical Specification Required Lift Pressure Testing.

Violations or deviations were not identified.

7. Facility Modifications - Unit 2 (37701)

This module's objective is to determine whether facility modifications that require prior NRC review and approval, pursuant to 10 CFR 50.59, are completed in accordance with the applicable requirements. Since the licensee made no modifications to the unit this outage under this category, this module is closed for this unit this SALP cycle.

8. Fitness For Duty: Inspection of Initial Training Programs (255104)

The NRC required licensees to implement a Fitness For Duty (FFD) rule, 10 CFR 26, on January 3, 1990. The general performance objectives of the rule, as stated in 10 CFR 26.10, are:

a. Provide reasonable assurance that nuclear power plant personnel will perform their tasks in a reliable and trustworthy manner and are not under the influence of any substance, legal or illegal, or mentally or physically impaired from any cause, which in any way adversely affects their ability to safely and competently perform their duties;

b. Provide reasonable measures for the early detection of persons who are not fit to perform activities within the scope of this Part; and

c. Have a goal of achieving a drug-free workplace and a workplace free of the effects of such substances.

The inspectors observed a four hour supervisor and a two hour employee training session. That training is required per 10 CFR 26.21, Policy Communications and Awareness Training, and 10 CFR 26.22, Training of Supervisors and Escorts. The inspectors also reviewed training materials given to the employees and existing General Employee Training (GET) materials. The inspectors reviewed the training to verify that the overall objectives of 10 CFR 26.21 and 22 were met but did not inspect compliance with each specific element of the training rules.

The inspectors concluded that the licensee met the general objectives of 10 CFR 26.21 and 22. Certain information, while not presented in the training, was included in GET or handouts. No specific training for escorts was conducted since any person badged on site is eligible to escort visitors. Specifically omitted from the training program as a violation of the FFD rule was illegal use of legal drugs. Training personnel at Brunswick reported that a recent change had deleted that requirement. The program description document, dated November 16, 1989, did specify that a program objective was to assure that personnel subject to the program were not under the influence of any substance, legal or illegal, that impairs their abilities. Any further inspection or followup of the FFD program will be conducted by the cognizant regional inspectors.

Violations or deviations were not identified.

9. Response to Events - Unit 2 Alert (93702)

The licensee declared an Alert when all audible annunciation was lost on Unit 2. Operators discovered the problem on December 22, 1989, at 3:25 p.m., and declared the Alert 20 minutes later. The operations staff stationed three extra operators at the Unit 2 control board to monitor the annunciator panels. The Technical Support Center (TSC) was activated at 4:41 p.m., with the plant manager as the Site Emergency Coordinator. By 4:45 p.m., the audible annunciators had been restored and tested satisfactorily. The TSC was deactivated and the Alert secured at 4:52 p.m.

Unit 2 was defueled during the event with the reactor vessel drained to allow replacement of the recirculation system piping (the risers) and reactor vessel safe ends. Fuel pool temperature was 77 degrees F. Thus, the safety significance of the event was small.

The audible function was lost while lifting a temporary jumper. That jumper was part of PM-87-056, Rework of Annunciator Acknowledgement/Reset in Panel XU-19. One wire to the permanent power supplies to certain annunciator relays had been inadvertently omitted from the plant modification instructions. Step 8.6.3.9 of the installation procedure, performed about 12:30 p.m., that day, disabled the audible annunciation. Operators were unaware of the loss until an I&C technician requested a test of an annunciator while working a trouble ticket. Very few alarms come in with the reactor defueled, so the operator was not previously alerted to the problem.

QA issued NCR S-90-001 to resolve the issue of the inadequate modification instructions. The inspector interviewed personnel and reviewed documentation concerning the event. The inspector did not go to the site during the event, with regional management concurrence, since the reactor was defueled and no threat to the public existed. The inspector had no further questions.

Violations or deviations were not identified.

10. Emergency Diesel Generator No. 1 Engine Driven Jacket Water Pump Failures (62703)

Based on a failure of the Engine Driven Jacket Water Pump (EDJWP) on No. 1 Emergency Diesel Generator this period, the inspectors reviewed the failure history, examined procurement records, observed maintenance and materials, and interviewed personnel to assure that the licensee properly handled the issue. The inspectors chose this maintenance and resolution for an in depth review because station blackout is a significant contributor to total core damage frequency. The inspectors found that two consecutive EDJWP failures had occurred and that the pump was procured commercial grade without involving the diesel vendor. Further, when the licensee called in the vendor to assist in troubleshooting, the vendor recommendations were initially not implemented with no technical justification. When pressed on the issue by NRC, the licensee corrected a vibration problem on DG No. 1 that would have had an unknown effect on the engine.

a. Chronology

A shaft failure of the EDG No. 1 Engine Driven Jacket Water Pump occurred on March 24, 1989. The pump had been installed in September, 1987, using one of two spare pumps stored onsite which were bought under the same purchase order in 1986. Because of the failure, the second spare pump was installed. The pumps are Gould model 3736 4X6-11G modified with a special power end to fit the Brunswick Nordberg diesels and were intended to be identical to those originally installed on the engines by Nordberg. The pumps were procured as "off the shelf" items directly from a Gould Pumps, Inc. representative instead of from the current Nordberg diesel vendor (Cooper-Bessemer).

Subsequent licensee failure analysis was inconclusive. The shaft sheared where it attached to the impeller. There was no evidence to suggest that binding of the impeller in the pump casing occurred.

Parts of the failed pump were sent for analysis to the Gould sub-tier vendor (A. A. Anderson) who performs the necessary modifications to fit the Brunswick diesels - including manufacture of a new shaft to fit the diesel power take off. In a letter dated July 12, 1989, to the licensee, the vendor stated that the failure appeared to be the result of some type of shock load and that several steps had been taken to improve the shaft design to assure that this failure would not occur again. The vendor did not specify what the design changes were, nor return the parts. On November 7, 1989, the licensee received from the sub-tier vendor two sets of replacement parts to replace those of the failed pump and to retrofit the second pump that was currently installed. Included was a new impeller trimmed to 8.625 inches diameter (from 11.25 inches). All previous information, including the Nordberg Technical Manual, indicated the impeller diameter to be 11.25 inches. The licensee did not know that the impeller diameter was reduced as part of the modifications to the standard Gould design. The vendor recommended replacement of the shaft and trimming of the impeller in the second pump as soon as possible to avoid another failure and to return the replaced parts. The licensee immediately initiated a work request/job order to conduct the repairs on the installed pump. However, the pump shaft failed again on November 16, prior to replacement. Upon removal of the second failed pump, the failure was found to be similar to the March 24, 1989 failure. The shaft was again sheared where it attached to the impeller. Again, there was no indication of impeller binding. The impeller diameter was discovered to be 11.25 inches - that of the original Gould design.

The licensee also noted discrepancies in the shaft dimensions. The impeller bolt hole in the shaft end was about one-half to five-eighths inch too deep and the radius was not machined at the diameter change of the shaft where the impeller was attached. The bolt hole depth and radius are shown on the pump composite drawing included in the Nordberg Technical Manual. The length of the installed impeller bolt corresponds to that shown on the drawing. Therefore, the extra depth bolt hole was unnecessary. The absence of a radius to remove the stress riser was significant. Rudimentary machining practice dictates the use of rounded corners to minimize stress risers. These discrepancies result in a stress riser existing near the base of the bolt hole, and coincides with the failure locations on both failed shafts. The licensee stated that the same shaft discrepancies existed on the first shaft that failed.

The size of the impeller may or may not have contributed to the failures even though the standard Gould pump contains an 11.25 inch impeller. There is no indication that the shaft modifications affected the impeller end. The as-found design, except for the noted discrepancies, should be the same as the standard Gould shaft. The shaft material for neither the modified shafts nor the Gould shafts was known.

The EDJWP is gear driven from a flexible gear drive attached to the engine crankshaft. The flex drive acts as a shock absorber between the engine crankshaft and gear driven loads which consist of the EDJWP and the engine driven lube oil pump. Following the second failure, two of the flex drive spring guides were found to be worn and their springs hung in the compressed state. The driven gear on the pump shaft had a broken tooth. These findings are consistent with the shaft failure, although which failure occurred first is indeterminate.

The reason for trimming the impeller from 11.25 to 8.625 inches is unknown by the licensee, pump or diesel vendors. The result is lower pressure and flow in the jacket water system. Based on indicated pressure, the three remaining Brunswick diesels have the reduced impellers installed. Subsequent to discovery of the reduced impeller design, the diesel vendor issued a drawing revision for the Nordberg Technical Manual identifying the correct impeller diameter.

Based on the information available, the inspector concluded that:

- The licensee could not have reasonably known of the need to reduce the impeller diameter.

- The most likely cause of the failures are the shaft machining deficiencies.

- The procurement method may have allowed the pump shaft deficiencies to go undetected, i. e., the pumps were procured as "off-the-shelf" commercial goods instead of Q-list.

The licensee's final root cause assessment is pending completion of analysis of failed parts by the Harris E&E center and restoration of the engine to original configuration planned for late 1990.

Following both of the EDJWP failures discussed above, the licensee considered the No. 1 Emergency Diesel Generator to be operable due to the redundant motor driven jacket water pump being available to automatically start and provide design jacket cooling water flow, which it did on both occasions.

Subsequent to the second EDJWP failure on November 16, 1989, the licensee removed the No. 1 EDG from service on November 30, 1989, to replace the EDJWP and perform other miscellaneous maintenance. The engine was tested and declared operable on December 2, 1989, following the repairs. During testing, a diesel vendor representative noted an unusual noise and vibration in the engine in the vicinity of the flex drive.

A special meeting of the PNSC was convened following the tests to address the vendor's concern, review the conclusions relative to the EDJWP failure, and determine operability of the EDG. The PNSC concluded that the EDG was operable based on the availability of the MDJWP should the EDJWP fail again and "that maintenance and engineering personnel familiar with EDG No. 1 did not observe any differences in noises emanating from the unit." PNSC directed that a trending program be established to detect pending failures in light of the vendor's concerns. The PNSC also deemed the vendor representative not creditable and directed additional vendor experts be obtained.

On December 3, EDG No.1 was tested again with additional vendor support, monitoring equipment, and the inspector present. The additional vendor representatives corroborated the first representative's concerns. The vendor determined the vibration occurred once per engine revolution and was highest in the vicinity of the EDJWP attachment to the engine - suggesting the gearing between the flex drive (which rotates once per revolution) and EDJWP to be the cause of the noise and vibration. Actual vibration magnitude could not be measured because it was in excess of the capability of the instrumentation.

The inspector questioned members of the operations staff present, the vendor representatives, and the technical support system engineer. The on-duty SCO stated that he had not heard the loud noises previously. The vendor representatives' concern shifted toward the flex drive with regard to unknown damage that may have been caused during the two EDJWP failures. They cited the condition of the flex drive springs and broken gear tooth as evidence that further damage could be present. They stated that a catastrophic failure of the flex drive could disable the engine. They further stated to the inspector that the engine should be disassembled to determine the exact cause of the problem. The system engineer stated he considered the engine to be inoperable and that his concerns were known to his management.

b. Conclusions

The inspector concluded that there was insufficient information to conclude that the EDG was operable. This conclusion was based on:

- Some licensee staff considered the noise no different from the past, but no vibration baseline was available for comparison.

- The second EDJWP resulted in a broken tooth on the driven gear which mates with the flex drive. Unknown flex drive damage was possible.

- The vendor and system engineer considered that further engine repairs were necessary.

- The possibility of unknown flex drive damage was not considered by PNSC when the engine was determined operable.

The licensee was notified of the NRC concerns by telephone on December 3, 1989, and implemented a vendor recommendation to remove the EDJWP drive gear and run the engine using the MDJWP. When this was done, the noise and vibration were not present. The engine was subsequently declared operable on December 6, 1989, within the original TS LCO time limit. Therefore, no violations or deviations occurred.

The inspectors concluded that licensee management used poor judgement declaring the EDG operable over vendor and system engineer concerns with no technical bases. Statements that the engine noise was no different from the past does not constitute sufficient technical bases for an operability determination. The inspectors told the licensee the results of their inspection during the exit interview. Plant management disagreed strongly with the inspectors' assessment. Since the licensee's actions during the event eventually were prudent and proper, the inspectors have no further questions on this issue.

Violations or deviations were not identified.

11. Action on Previous Inspection Findings (71707) (92702)

a. (OPEN) URI 325/89-40-02 and 324/89-40-02, Fire Protection Sprinkler Actuation During HELB May Affect EQ Components. Inspection report 89-40 described the circumstances of this issue. The licensee was first questioned on this issue by NRC on November 29, 1989, and not on November 28, 1989, as reported in 89-40. Since that time, the licensee has conducted a walkdown of Unit 1 safety-related equipment to determine the effects of sprinkler actuation on safety-related equipment. Equipment within a 15 foot radius of each sprinkler head was examined to determine if the appropriate design features were in place to mitigate effects of water intrusion. The licensee selected a 15 foot radius based on a sprinkler spray pattern. The walkdown found that equipment was generally in accordance with design. Approximately 18 deficiencies were found which required evaluation by NED. A walkdown of Unit 2, currently in a refueling outage, was in progress at the end of the inspection period.

   The licensee has replaced the sprinkler heads in the North and South RHR rooms and the South RHR water curtain area with sprinkler heads designed to actuate at 350 degrees F. The previous sprinkler heads were designed to actuate at 165 degrees F. A roving hourly fire watch still exists for the South RHR water curtain area while NED further studies the installation of the 350 degrees F sprinkler heads for this area. NED's initial evaluation concluded that the 350 degrees F sprinkler heads were not adequate for Appendix R purposes.

   The licensee has also issued a Standing Instruction to the operators describing additional actions that must be taken in the event of a HELB in the Unit 1 Reactor Building. In the event of a HELB, the operator instructs an individual stationed in the vicinity of the fire system water shutoff valve to the Unit 1 Reactor Building to close the shutoff valve. The individual closes the valve and reports its accomplishment to the Control Room. All individuals who are stationed to close the shutoff valve have been trained in this evolution and have been timed to ensure that the valve can be closed in a timely manner. The approximate time to close the valve once the individual is instructed to do so is one minute.

Further evaluation of this issue is being conducted by NED. The following evaluations, in addition to the two previously mentioned, are in progress:

- Operability assessment of leak detection system with the 165 degrees F sprinkler heads.

- Researching flood studies to determine if actuation of all sprinkler heads was previously analyzed. NED will perform study if none found.

- Researching HPCI/RCIC leak detection historical files for basis for location of detector and its setpoint.

- Verifying EQ profile encompasses sprinkler head actuation/HELB event.

- Walkdown of Unit 2 safety-related equipment.

Completion of these items is scheduled for February 12, 1990. The inspectors will continue to monitor the licensee's efforts in this area. At this time, the inspectors have no further concerns regarding the compensatory measures that the licensee has in place.

b. (CLOSED) Violation 324/89-20-08, Performing a "During Shutdown" Surveillance Test While at Power. This violation resulted from performing TS 18 month surveillance 4.1.5.c.3, SLC Relief Valve Setpoint Check, while at power instead of "during shutdown" as required by TS. The licensee attributed the cause to a misinterpretation of the shutdown requirement and due to the Surveillance Test Scheduling System (STSS) not flagging this surveillance to be performed during an outage. Unit 2 had just undergone a forced outage that could have accommodated the surveillance while shutdown. The performance of this surveillance requires that both trains of SLC be disabled and the unit placed into an eight hour action statement in accordance with TS. The licensee stated, in the response to the violation dated October 23, 1989, that STSS "was annotated to schedule the SLC relief valve surveillance during an outage." On December 19, 1989, during routine work request/job order review, the inspector noted that two WR/JOs (89-BBQF1 and 89-BBQG1) had been initiated and received initial control room approval to perform the SLC relief valve surveillance in Unit 1. The scheduled date for performance was indicated to be

December 25, 1989. The surveillance must be completed by May 11, 1990 to be in compliance with TS. Unit 1 was at power with no scheduled shutdowns in the near future.

The inspector reviewed STSS data which revealed that the surveillance was still not flagged for performance during an outage. As was the case for the violation, the affected unit had recently undergone a forced outage which could have accommodated the surveillance while shutdown. On December 22, 1989, the inspector alerted Regulatory Compliance of the problem. Subsequently, the licensee stated that, because of miscommunication within the licensee's staff, STSS had not been annotated as stated in the response to the violation. The licensee added that the problem would have been detected prior to final approval for the work to be done.

10 CFR 50.9(a) requires that information provided to the NRC shall be complete and accurate in all material respects. Since the licensee stated, in the response to this violation, that the STSS data base had been corrected when, in fact, it had not, this constitutes a violation of 10 CFR 50.9(a). This is a Violation: Failure to Supply Complete and Accurate Information About STSS Database Update, (325/89-44-02). The NRC does not consider the violation to be willful.

As stated above, the surveillance must be completed by May 11, 1990. The licensee has no scheduled outages prior to that date. Therefore, the licensee must either schedule another outage or seek regulatory relief if no unplanned shutdown occurs to accommodate this surveillance. The licensee stated that this surveillance has been added to their list of required maintenance should an unplanned shutdown occur.

One violation and no deviations were identified.

12. Cold Weather Preparations (71714)

The inspector reviewed licensee preparations for operations during cold weather. OI-43, Freeze Protection and Cold Weather Bill, Revision 2, provides specific actions that must be taken at various outside temperatures. Other procedures accomplished coincidentally with OI-43 are FPP-024, Freeze Protection of Fire Suppression Systems, Revision 5, and OPM-HT-001, Preventive Maintenance on Plant Freeze Protection and Heat Tracing System. The inspector verified through review of documentation and direct observation that the licensee implemented their procedures as written.

The site had unusually cold weather during this inspection period. A preliminary review of meteorological data showed that the temperature reached a low of 7 degrees F at the Brunswick Plant. Present OI-43 actions must be taken when temperatures reach 20 degrees F. Prior to these cold conditions occurring, the inspector questioned the operability of the two outside diesel fuel oil storage tanks if temperatures were to reach the predicated lows. One tank provides fuel oil to the diesel driven fire pump (minimum TS capacity 500 gallons) while the other tank provides gravity makeup to the emergency diesel generator 4 day tanks (minimum TS capacity 74,000 gallons). The operability of the fuel oil during the predicted cold conditions was raised since the fuel oil procured by the licensee had a specified maximum pour point of 20 degrees F. The pour point is defined in the DIESEL ENGINEERING HANDBOOK, Karl W. Stinson, M. E., 12th Edition, as "the temperature 5 degrees F above that at which the oil becomes solid or refuses to flow."

In response to the inspector's question, the licensee provided a means to keep the diesel fire pump fuel oil tank warm and issued a Standing Instruction to the operators for actions they must take to maintain the 7 day tank and 4 day tanks operable during the predicted cold weather. The inspector noted that people were available to provide heating for the 7 day tank to 4 day tank transfer lines but no specific temperature was specified when this would occur. Plant management indicated these actions would occur when outside temperature reached 0 degrees F. The inspector found no information to support a proper temperature for heating these transfer lines. The lines are approximately two inches in diameter and, neither the licensee nor the inspector knew what temperature would restrict flow. The licensee did state that OI-43 would be revised to include precautions for diesel fuel oil and, as part of the revision, the technical basis for the selected temperature would be established. The inspector will monitor the procedure revision and its implementation during future routine inspections.

The extreme cold weather also rendered the stack radiation monitor inoperable. The monitor was declared inoperable on December 23, 1989 at 12:30 a.m., due to low flow. At 1:35 p.m. the same day, the licensee concluded that the sample line from the stack to the monitor had been blocked with ice. TS 3.3.5.9 ACTION statement for this instrument allows effluent releases to continue out the stack provided grab samples are taken at least once per 12 hours and analyzed for gross noble gas activity within 24 hours. Since the grab samples could not be taken, the licensee could not comply with the ACTION statement. However, since TS 3.0.3 and 3.0.4 are not applicable to the specification, a plant shutdown was not required. The shift foreman requested additional samples of gaseous effluents that go to the stack. With Unit 1 at full power and Unit 2 defueled with drywell purge in progress, the licensee noted no unusual radio-chemistry results. The stack sample pump and radiation monitor were returned to service on December 25 at 7:30 a.m., with the sample line thawed.

Since the above event constitutes operation outside the TS, the licensee plans to report the event per 10 CFR 50.73(a)(2)(i)(B). The inspectors will complete their inspection after the LER is issued.

13. TMI Action Item (25565)

(CLOSED) Item II.E.4.2.7, Containment Isolation - High Radiation Signal. Previous inspection of this item was documented in Inspection Reports 325, 324/82-08, 85-38, 89-40 and 325/86-24, 324/86-25. As reported in 89-40, there was a discrepancy regarding information provided in a December 17, 1986 submittal describing the electrical separation between the safety and non-safety circuits. Specifically, the licensee stated that a fuse was purchased Q-list when it was, in fact, purchased commercial grade. In addition, the licensee stated that a relay used for electrical separation was rated at 600 V. The relay was installed in a 120 VAC circuit with a 120 VAC coil. The licensee committed to revise their December 17, 1986 submittal, during the exit interview, to accurately reflect what is installed along with the technical basis for its use.

Based on this submittal, inspection of this item is complete and the item is closed for both units. Future discussions, if any, regarding the acceptability of the means of electrical separation will be between NRR and the licensee.

14. Installation and Testing Modifications - Unit 2 (37828)

The inspector observed the installation of a Patel conduit seal for transmitter 2-PNF-PSL-5843B as part of PM-87-170, Pneumatic Nitrogen System. The inspector verified that the environmentally qualified seal was installed in accordance with the installation instructions contained in specification 111-03, section 3.1, as modified by specification waiver SWN-111-03A. The licensee measured the outside diameter of the wire prior to selecting seal size, allowing for a correct fit. The inspector reviewed the seal design with the cognizant engineer who also observed the installation. The inspector concluded that the seal was correctly installed.

Violations and deviations were not identified.

15. Exit Interview (30703)

The major inspection scope and findings were summarized on January 5, 1990, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the report summary. The plant manager disagreed strongly with the inspectors' view of certain licensee management's actions regarding the troubleshooting and repair of diesel generator No. 1. No other dissenting comments were made. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
325/89-44-01	VIOLATION - Failure to Follow AI-58 for Drawing Research, (paragraph 4.a).
325/89-44-02	VIOLATION - Failure to Supply Complete and Accurate Information About STSS Database Update, (paragraph 11.c).

16. List of Abbreviations for Unit 1 and 2

AI	Administrative Instruction
AO	Auxiliary Operator
ADS	Automatic Depressurization System
BSEP	Brunswick Steam Electric Plant
CAC	Containment Atmospheric Control
CATQ	Condition Adverse to Quality
CO	Control Operator
CP&L	Carolina Power and Light Company
CRD	Control Rod Drive
CS	Core Spray
DG	Diesel Generator
DSR	Daily Surveillance Report
E&E	Energy & Environment
EDG	Emergency Diesel Generator
EDJWP	Engine Driven Jacket Water Pump
ESF	Engineered Safety Feature
EQ	Environmental Qualification
F	Degrees Fahrenheit
FFD	Fitness For Duty
FPP	Fire Protection Procedure
GET	General Employee Training
HELB	High Energy Line Break
HP	Health Physics
HPCI	High Pressure Coolant Injection
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
IPBS	Integrated Planning, Budgeting and Scheduling
IRM	Intermediate Range Monitor
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
MDJWP	Motor Driven Jacket Water Pump
MG	Motor Generator
MST	Maintenance Surveillance Test
NCR	Non-Conformance Report
NED	Nuclear Engineering Department
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation

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OI	Operating Instruction
OP	Operating Procedure
OPM	Operating Procedure Manual
PA	Protected Area
PM	Plant Modification
PNSC	Plant Nuclear Safety Committee
PT	Periodic Test
QA	Quality Assurance
QC	Quality Control
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPS	Reactor Protection System
SALP	Systematic Assessment of Licensee Performance
SCO	Senior Control Operator
SDV	Scram Discharge Volume
SLC	Standby Liquid Control
SRM	Source Range Monitor
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
STA	Shift Technical Advisor
STSS	Surveillance Test Scheduling System
TS	Technical Specification
TSC	Technical Support Center
URI	Unresolved Item
VAC	Volt Alternating Current
WR/JO	Work Request/Job Order