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

Report Nos.: 50-338/95-22 and 50-339/95-22

Licensee: Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060

Docket Nos.: 50-338 and 50-339

License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: November 19 through December 16, 1995

Lead Inspector: L W Garner For — 1-9-96
R. McWhorter, Senior Resident Inspector — Date Signed

Inspectors: D. R. Taylor, Resident Inspector
L. W. Garner, Project Engineer (paragraphs 2.2, 2.3, 2.4, 3.3, and 3.4)

Approved by: G A Belisle — 01/09/96
G. A. Belisle, Chief — Date Signed
Reactor Projects Branch 5
Division of Reactor Projects

SUMMARY

Scope:

Inspections were conducted by the resident and regional inspectors in the areas of plant operations, maintenance, engineering, and plant support activities.

ENCLOSURE

9601190022 960110
PDR ADOCK 05000338
G PDR

Results:

Plant Operations

Control room habitability systems were found to be properly aligned and maintained (paragraph 2.5).

Quality assurance audits were completed in accordance with regulatory requirements. Recent reorganizations of station quality functions resulted in fewer daily independent self-assessments of station activities being provided to station management by station oversight organizations (paragraph 2.7).

Maintenance

Two material deficiencies were identified which indicated a lack of attention to detail during past maintenance activities. A flex conduit support for a safety-related motor operated valve was not correctly re-assembled, and a turbine-driven auxiliary feedwater pump overspeed trip mechanism was positioned such that the latch hook was not fully engaged with the latch lever (paragraphs 2.2 and 2.3).

Problems with an emergency diesel generator shutdown circuit were appropriately resolved. Initial coordination for the troubleshooting efforts was lacking clear supervisory control (paragraph 3.1).

Three surveillance tests were properly performed (paragraphs 3.2, 3.3, and 3.4).

Maintenance to repair an inverter ground was properly performed (paragraph 3.5).

Engineering

A weakness was identified in the licensee's understanding and implementing NRC Generic Letter 90-06 requirements (paragraph 4.2.1).

Plant Support

The discovery of old blasting wires within the protected area was appropriately resolved (paragraph 5.1).

REPORT DETAILS

Acronyms used throughout this report are listed in paragraph 8.

1.0 Persons Contacted

Licensee Employees

Edmonds, L., Superintendent, Nuclear Training
*Funderburk, C., Superintendent, Outage and Planning
#*Hayes, J., Superintendent, Operations
#*Heacock, D., Assistant Station Manager, Nuclear Safety and Licensing
*Kemp, P., Supervisor, Licensing
Matthews, W., Assistant Station Manager, Operations and Maintenance
Roberts, D., Supervisor, Station Nuclear Safety
*Royal, H., Director, Nuclear Oversight
*Saunders, R., Vice President, Nuclear Operations
Schappell, D., Superintendent, Site Services
Shears, R., Superintendent, Maintenance
#*Smith, J., Superintendent, Station Engineering
Stafford, A., Superintendent, Radiological Protection
#*Stall, J., Station Manager
*Williams, T., Manager,Nuclear Oversight

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

#Attended Exit Interview on December 8
*Attended Exit Interview on December 21

2.0 PLANT OPERATIONS (40500, 71707, 92700)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations and reviewed operator logs to verify operational safety and compliance with TS. Instrumentation and safety system lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status and housekeeping. DRs were reviewed to assure that potential safety concerns were properly reported and resolved.

2.1 Plant Status

Unit 1 operated the entire inspection period at or near full power until December 15. On that date, the unit began a coast down to a refueling outage scheduled to begin in mid-February 1996. At the inspection period's end, the unit was at approximately 99 percent power.

Unit 2 operated the entire inspection period at or near full power.

2.2 Unattached Cabling Support

On December 5, during a routine tour of the Auxiliary Building, the inspectors noted that the power and control cable flex conduits for 2-SI-MOV-2863A were not properly supported. The MOV served as the Unit 2 low head safety injection pump discharge to charging pump suction header isolation valve. The three flex conduits were attached to a section of unistrut, but the unistrut was not attached to its stanchion. This condition was reported to Operations personnel and was subsequently evaluated by a civil design engineer (DR N-95-1915). Although the design maximum unsupported length was exceeded, the evaluation concluded that the MOV remained operable. On December 6, the flex conduit support unistrut was re-attached to its stanchion by technicians per WO 00331135-01.

The inspectors observed that there was no evidence of any mechanism such as vibration that could have loosened the two attachment bolts and the bolts and washers were not in the area. There were no recent modifications to the MOV. The inspectors reviewed, with the licensee, previous WOs performed on the MOV. Maintenance work that could have disassembled the flex conduit support was last performed on the MOV during the previous Unit 2 RFO. The inspectors concluded that the flex conduit support had been disassembled during previous maintenance or modification activities and had not been properly re-assembled for at least seven and one-half months.

2.3 TDAFW Pump Latch Problem

On December 6, during a routine outside area tour, the inspectors observed that the Unit 2 TDAFW pump manual/overspeed trip mechanism latch hook was not fully engaged. Specifically, there was only approximately 50 percent surface contact between the latch hook and the latch lever. Although the inspectors considered that the engagement was adequate to prevent an inadvertent trip of the TDAFW pump, the inspectors were concerned that the condition had resulted from either improper latching techniques by Operations personnel or from improper linkage adjustment during maintenance. This discrepancy was discussed with operations and engineering personnel.

On December 13, following the monthly surveillance test, the mechanism was tripped and relatched several times. The inspectors observed that this evolution demonstrated that the trip mechanism was being properly latched and that an adjustment of a connecting rod would be necessary to correct the condition. Operators informed the inspectors that a WR would be initiated to correct the problem during the next appropriate unit outage. The inspectors concluded that the licensee's response was appropriate.

2.4 New Fuel Receipt Inspection

On December 7, the inspectors witnessed the receipt inspection and storage of new fuel assemblies RD6 and RD8. The receipt inspections consisted of visual verifications that the fuel assemblies were undamaged as a result of shipment and subsequent unpacking. The inspectors verified that these inspections were conducted in accordance with appropriate procedures and the fuel assemblies were handled with proper precautions and care. The fuel assemblies were observed to be free of debris and showed no signs of physical damage.

2.5 ESF System Walkdown

During the period from December 13 - 15, the inspectors performed walkdowns of the control room habitability systems. A detailed walkdown for Unit 1 A and C chillers and cooling coils was conducted using station drawings and procedures 1-OP-21.6, Main Control and Relay Room Air Conditioning, revision 14-P2, and 0-OP-21.6A, Valve Checkoff - Control and Relay Room Chilled Water, revision 2-P1. Both units' bottled air pressurization systems, emergency ventilation systems, and the remaining chillers were walked down in less detail. The inspectors found that the systems were properly aligned and adequately maintained.

2.6 NRC Notifications

The inspectors reviewed the following licensee notifications to the NRC to ascertain if the required reports were adequate, timely and proper for the events.

On November 27, the licensee notified the NRC as required by 10 CFR 50.72 concerning the notification of off-site authorities. Specifically, the licensee notified the Virginia State Department of Emergency Services concerning an unplanned emergency siren activation. At approximately 11:50 a.m., one emergency siren activated for unknown reasons and with an abnormal tone. The licensee investigated the event and found that the siren activated during system testing which should not have initiated the siren. The activation system and all other sirens were found to be operating normally. The licensee declared the siren inoperable and, with vendor assistance, attempted to identify the cause of the problem, but were unsuccessful. The licensee then returned the siren to service. The inspectors monitored the licensee's actions and found them to be appropriate for the situation.

2.7 Evaluation of Licensee Self-Assessment Activities

Self-assessment programs were reviewed to determine if programs contributed to the prevention of plant problems by monitoring and evaluating plant performance, providing assessments and findings, and communicating and following up on corrective action recommendations.

Nuclear Oversight Effectiveness

During the fall of 1995, the licensee performed a detailed oversight activities review at both nuclear stations and the corporate offices. This review was completed in early October and changes became effective November 1. The changes moved several activities previously performed by the QA organization into station line organizations and reduced the overall size of oversight organizations by approximately one-third (40 individuals). The major changes at the station included: 1) QC inspections required as a part of field activities were made the responsibility of technicians within the station maintenance organization under the direction of a station inspection coordinator, 2) QA programmatic assessment activities were replaced by organizational self-assessments to be coordinated by the station licensing organization, and 3) reduced daily oversight and audit activities by a new organization named Nuclear Oversight. These changes were the topic of a meeting held between the licensee and NRC Region II staff on September 12.

During this inspection period, the inspectors assessed the initial impact of these changes on the organization's effectiveness including implementing QA Topical Report, UFSAR Chapter 17, and TS 6.5.2.8 requirements. The inspectors reviewed recent findings, reviewed Oversight daily reports, observed Oversight personnel involvement in daily plant activities, and observed Oversight management interaction with station management. On November 30, the inspectors met with Oversight supervisors to discuss the new organization's functions, the status of audit programs, and recent findings. The inspectors obtained and reviewed audit schedules and the results of audits completed since July 1995.

The inspectors' reviews identified the following:

- All audits required to be completed by the licensee were being performed within the required intervals.

- A post-audit conference and report for one audit (corrective action program) was delayed for approximately two months. This delay was due to difficulties in characterizing findings caused, in part, by changes in audit leadership resulting from the reorganization.

- Significant issues continued to be identified by audits and DRs continued to be submitted by Oversight. However, the number of DRs submitted by Oversight was lower.

- The Oversight daily report (formerly QA daily report) and Oversight managers attending daily station management meetings provided fewer daily performance observations of interest to station management.

- Involvement of Oversight inspectors in evaluating daily activities (considered a strength by inspectors in June 1994 - NRC Inspection Report Nos. 50-338, 339/94-13) was reduced. In the past, most of the QA organization had been considered a part of this function, but this activity had now been restricted primarily to four individual specialist inspectors. The specific duties of these four inspectors were still being refined during this inspection period.

The inspectors reviewed the findings and observations and concluded that regulatory requirements for audits continued to be met. However, the new Oversight organization was contributing less value than the former QA organization with regards to providing station management with daily independent self-assessments of station activities.

The inspectors discussed these conclusions with licensee management. Management stated that they recognized that the interaction between Oversight and station management had changed. However, they believed that the new organization was providing better quality information using new and different techniques. Management agreed to provide inspectors with additional information on these new self-assessment activities.

2.8 Close Out Issues

The following LER was reviewed and closed. The inspectors verified that reporting requirements had been met, causes had been identified, corrective actions appeared appropriate, and generic applicability had been considered.

(Closed) LER 50-339/95-04: Automatic Reactor Trip Due to Loss of "B" Control Rod Drive Motor Generator Set

This LER concerned an event on November 11 when Unit 2 tripped from full power due to a sequential loss of both rod drive MG sets. The licensee's response to the event and initial corrective actions for the associated equipment failures were reviewed and found to be adequate by the inspectors during the previous inspection period (NRC Inspection Report Nos. 50-338, 339/95-20). The inspectors also reviewed the results of the licensee's formal RCE and long-term corrective actions and found them to be appropriate.

No violations or deviations were identified.

3.0 MAINTENANCE (62703, 61726, 92700, 92902)

Maintenance activities were observed and reviewed to verify that activities were conducted in accordance with TS and procedures, and licensee commitments to regulatory guides and industry codes or standards. Surveillance testing activities were observed and reviewed to verify that testing was performed in accordance with procedures, test instrumentation was calibrated, LCOs were met, and any deficiencies identified were properly reviewed and resolved.

3.1 Emergency Diesel Generator Problems

On November 30, operators performing 1-PT-82H, 1H Emergency Diesel Generator Slow Start Test, revision 14, observed that the B air start SOV stuck open after starting and allowed the B starting air receiver pressure to bleed to near zero before it reseated. Additionally, shortly following EDG shutdown, the operators received several unexpected annunciators. These included the "shutdown interlocks not reset" alarm and several automatic shutdown alarms. The operators did not observe any abnormalities which could have generated the alarms. The inspectors responded to the EDG room and observed the alarms which were present and the licensee's subsequent troubleshooting and repair activities.

Initially, numerous engineers, technicians and supervisors responded to the area to participate in troubleshooting. Under the direction of supervisors and with a properly authorized WO, electricians checked various switches and relays in the shutdown circuits to determine if abnormal conditions existed. Simultaneously, system engineers interviewed operations personnel concerning their actions and observations. The inspectors observed that these activities were properly performed. However, overall initial task coordination appeared to lack clear supervision and direction. Although the electricians ultimately checked all circuit portions, there was no pre-defined strategy for their activities. After several hours of troubleshooting, no component failures were identified, and all personnel met in the maintenance shop to analyze their findings and plan additional actions.

The inspectors observed personnel briefing the Maintenance Superintendent on their plans for additional actions. The plans included replacing three time delay relays in which timing errors could have caused the problem, as well as, calibrating pressure switches which could have erroneously initiated the shutdown signals. During the meeting, the inspectors observed that all attendees understood that another maintenance activity, replacing the stuck air start SOV, would be started after the meeting. However, inspectors in the field observed that while the meeting was going on, work had begun to replace the air start SOV. This work was not totally unrelated to the shutdown circuit problem because its accomplishment included de-energizing a portion of the shutdown circuit. This mis-communication between key maintenance personnel pursuing the shutdown circuit problem and technicians working to replace the SOV reinforced the inspectors' conclusion that initial coordination for the troubleshooting efforts lacked clear supervisory control.

The inspectors then observed relay replacement and testing. The inspectors observed and discussed with electricians the as-found test performed on three relays which were suspected as being the most likely components to have failed. The relays tested satisfactory but were replaced as a precautionary measure. During the replacement activities, the inspectors observed one case where IV practices were used instead of SV practices for landing leads. Since the circuit was deenergized, use of IV had no safety consequences. This was discussed with a supervisor at the scene who coached the individuals involved. Later, a DR was initiated (DR N-95-1989).

After repairs were completed, the licensee satisfactorily conducted a maintenance run to retest the replaced components and successfully re-performed 1-PT-82H. During these runs, technicians closely monitored the shutdown circuit and were able to identify a probable cause for the problem. Due to the timing intricacies and unexpectedly long times required for lube oil pressures to bleed away, it was found that the operators could affect circuit operation by varying the duration of time in which the shutdown pushbuttons were depressed. The operators were informed concerning this finding and operator aids were posted to inform operators to hold the shutdown pushbuttons long enough for the oil pressure to bleed off.

Following SNSOC review for the repair and retest activities, the EDG was returned to operable status on December 1. The inspectors reviewed the licensee's diagnosis of the problem and the corrective actions taken and concluded that they were appropriate. Additionally, the inspectors noted that the observed problems would not have affected the EDG's ability to start or perform its designed safety functions. At the inspection period's end, the licensee planned to observe operation of the other three EDGs during monthly surveillance tests to determine if similar problems existed. Additional long term corrective actions were also being planned.

3.2 Turbine Valve Testing

On December 1, the inspectors observed operators performing 1-PT-34.3, Turbine Valve Freedom Test, revision 8-P2. The test was being conducted to satisfy TS surveillance requirement 4.7.1.7.2 which required valve cycling each 31 days to verify valve freedom. The inspectors observed governor valve testing from the EHC panel, throttle valve testing from the turbine deck, and intercept and reheat valve testing from the control room. Other than a need to adjust the open limit switch for the 1R intercept valve, no problems were experienced during the test.

3.3 EDG Surveillance Test

On December 6, the inspectors observed operators performing 2-PT-82J, Emergency Diesel Generator Slow Start, revision 16. For this test, the 2J EDG was brought up to rated speed after a slow speed start and then loaded to its nominal rating for greater than one hour before being shutdown. The inspectors verified that the test was performed in accordance with the procedure and the procedural acceptance criteria were met.

Before the test performance, a cover was installed over the 2J EDG start switch in the control room. This installation was a human factors enhancement recommended by an RCE to reduce the likelihood that the EDG switch would be mistakenly operated when nearby similar looking switches that serve other functions were required to be manipulated. Similar changes had already been performed on the 1J and 2H EDG start switches. After the cover installation, the inspectors verified that the EDG start switch had been properly re-installed and that surrounding wiring had not been damaged or loosened. The performance of 2-PT-82J successfully demonstrated that the cover installation had not adversely affected the EDG starting circuit.

3.4 Degraded Voltage/Loss of Voltage and ESF Response Time Test

On December 7, the inspectors observed technicians performing portions of 1-PT-36.11, Degraded Voltage/Loss of Voltage Functional and ESF Response Time Test: 1J Bus, revision 8. The test procedure was adhered to and communications among personnel were good. The inspectors subsequently reviewed the completed procedure and independently verified that values derived from strip chart data were correct and that the test procedure acceptance criteria were met.

3.5 Inverter Maintenance

On December 8, the inspectors observed technicians performing maintenance to troubleshoot and correct a ground associated with 120 volt vital bus 2-I. Previous troubleshooting had located the ground on the bus's inverter ground detection circuit. The inspectors observed vital bus transfer from the inverter to a regulated transformer, inverter tagout, ground detection circuit component replacement, and inverter return to service. Good self check and verification methods were employed by operators and maintenance technicians. Maintenance and operations supervision were present during the entire evolution. During the maintenance, the inspectors noted two minor procedural discrepancies. First, although it was clear that the correct breakers were being operated, the noun names for breakers used to unload the inverter did not directly match the names listed in the procedure used to remove the inverter from service. Second, inconsistencies existed between the operating procedure and the electrical maintenance procedure regarding the required post-maintenance warm-up times for the inverter. These items were discussed with appropriate supervisors for corrective action.

3.6 Close Out Issues

The following previous inspection items were reviewed and closed. For the LER, the inspectors verified that reporting requirements had been met, causes had been identified, corrective actions appeared appropriate, and generic applicability had been considered. For the violation, the licensee's actions in response to the violation were reviewed to establish that corrective actions had been completed and that programs and practices had been strengthened to prevent recurrence.

3.6.1 (Closed) LER 50-339/95-03: Inoperable Containment Personnel Air Lock Outer Door Due to Open Personnel Hatch Vent Valve

This LER concerned a problem identified by the licensee on November 6 when an air lock test connection valve was identified as having been left opened and uncapped for approximately five days following surveillance testing. The valve's condition rendered the containment air lock outer door inoperable. During the time frame that the valve was open and uncapped, the licensee failed to take actions required by TS, and this was the subject of Violation 50-339/95-20-02. The licensee's initial corrective actions included returning the valve to its correct position and initiating an RCE for the event. The inspectors will review the RCE results and additional corrective actions during closeout for the violation.

3.6.2 (Closed) VIO 50-339/94-13-01: Failure to Use Procedure for Transformer Maintenance

This violation concerned a problem identified on June 8, 1994, when operators conducting a unit heatup observed an abnormally low voltage on busses supplied by the B RSST. Investigations revealed that the low voltage was caused by an inoperable automatic tap changer on the transformer. The tap changer was rendered inoperable because a switch in the voltage sensing circuit had been mistakenly left open during maintenance on June 3. Following the event, an engineering analysis was performed which demonstrated that the transformer remained able to perform its designed safety functions for the plant conditions present during the period when the tap changer was inoperable.

During initial reviews, the inspectors had concluded that the problem's primary cause was the licensee's failure to use procedures for controlling the transformer maintenance. A contributing cause was the licensee's failure to perform an adequate retest prior to returning the transformer to service. In the licensee's response to the violation, dated August 15, 1994, the licensee agreed that a violation of regulatory requirements occurred, but disagreed with the inspectors in their conclusion that the violation was a failure to use procedures for the maintenance activity. Rather, the licensee contended that the violation was in failing to have adequate procedures to control the return-to-service testing following maintenance activities. The inspectors reviewed the licensee's contention and concluded that it was an equivalent approach to the issue since either proper maintenance procedures or proper testing procedures would be adequate to meet the overall regulatory requirements for ensuring quality during maintenance activities. Consequently, the inspectors accepted the licensee's approach to corrective actions based on ensuring adequate return-to-service testing during future transformer maintenance activities.

Initial corrective actions completed by the licensee included returning the tap changer to proper operation, modifying transformer maintenance procedures to require checking the position of the voltage sensing switch, and performing a functional test of the tap changer prior to returning a transformer to service. The licensee also performed an RCE for the event. Additional corrective actions initiated following the RCE included upgrading RSST maintenance procedures to require more stringent configuration controls during maintenance, upgrading switchyard policy documents to clarify requirements for procedure usage and SNSOC approvals, adding the RSSTs to existing post-maintenance testing databases, and modifying operator logs to require earlier recognition of potential tap changer inoperability. The inspectors verified that these corrective actions had been completed.

During the period from November 27 - 29, 1995, the licensee removed the A RSST from service for routine maintenance. On November 28, the inspectors reviewed activities at the work area. The inspectors verified that transformer maintenance procedure NA-M-DSE-610, North Anna Switchyard - Maintenance for Transformer Bank RSST "A" and Disconnect Switch #1415, revision 3, was present at the work area and had been used by technicians to control configuration changes. On November 29, the licensee successfully returned the A RSST to service. The inspectors verified that appropriate retests were completed prior to the return to service, and noted that the SNSOC had also reviewed all work and retests prior to declaring the transformer operable.

The inspectors concluded that the licensee's NOV response dated August 15, 1994, and corrective actions were appropriate and had been properly implemented.

No violations or deviations were identified.

4.0 ENGINEERING (37551, 92903)

On-site engineering activities were reviewed to determine their effectiveness in preventing, identifying and resolving safety issues, events and problems.

4.1 Vessel Head Penetration Inspection Plans

On December 12, the inspectors met with engineers to discuss plans to inspect VHPs for cracking during the upcoming Unit 1 outage in February 1996. The engineers briefed the inspectors concerning industry history of VHP cracks and the high susceptibility of the North Anna reactors to this generic problem. The engineers also presented the plans for inspections, status of acceptance criteria development, and plans for possible repair efforts. The inspectors found that the plans for the inspections were appropriate and will continue to follow this issue.

4.2 Close Out Issues

The following previous inspection items were reviewed and closed.

4.2.1 (Closed) URI 50-338, 339/94-30-01: PORV Nitrogen Accumulator Requirements

This item concerned the requirements for PORV nitrogen accumulator pressurization to support operability for the pressurizer PORVs during MODEs 1-3. The licensee had previously taken a position that the PORVs' nitrogen accumulators were not required to be pressurized as a condition for PORV operability. This was documented and approved by a SNSOC memorandum dated December 1, 1994. The inspectors reviewed PORV operability requirements and did not agree with this position (NRC Inspection Report Nos. 50-338, 339/94-30). The following sequence of events summarizes the issue.

- On March 16, 1993, a letter from the NRC informed the licensee that their response to GL 90-06, Resolution of Generic Issue 70, "Power Operated Relief Valve and Block Valve Reliability," and Generic Issue 94, "Additional Low-Temperature Overpressure Protection For Light-Water Reactors," was not an acceptable response. The letter primarily referred to the fact that North Anna was no longer pursuing the "MERITS" TSs, but also referred to testing requirements for the safety backup PORV nitrogen accumulator supply.

- On May 21, 1993, the licensee responded to the NRC by letter. In that letter, the licensee committed to testing control air system check valves for the PORVs to assure the capability of the safety backup supply (nitrogen accumulators). The licensee also committed to submit a TS change to the NRC for review no latter than March 31, 1994.

- On April 11, 1994, DR N-94-471, was originated by corporate licensing, and alerted the station that contrary to NRC commitments, the nitrogen accumulators were not being maintained pressurized during plant operations. The station's response to the DR concluded that the above condition was neither safety-significant nor reportable. Guidance was given to the operators that if pressure could not be maintained above 1000 psig, a WO should be initiated and an "information only" action statement or abnormal status log entry should be made.

- On May 31, 1994, TS change requests regarding the PORVs were submitted to the NRC. The amendments (189 and 170) were approved by the NRC on October 5, 1994, with a required implementation within 60 days. Just prior to implementation, the licensee recognized that the new TS surveillance requirements included testing valves associated with the nitrogen accumulators. Questions once again were raised by licensee's staff concerning nitrogen accumulator pressure requirements for PORV operability.

- On December 1, 1994, a TS interpretation was approved by SNSOC which stated that the backup nitrogen accumulators were not required for the PORVs to meet the operability requirements specified by TS. At that time, the inspectors questioned licensee management whether the TS interpretation was correct and whether the position met the intent of the GL for maintaining the safety backup nitrogen accumulators available.

- From 3:37 a.m., on December 4, until 5:04 a.m., on December 5, 1994, pressure in one or both of the PORV's nitrogen accumulators was less than 1000 psig, and was as low as 150 psig prior to re-pressurizing. Following December 5, pressure was maintained greater than 1000 psig, at management's direction.

- On January 18, 1995, after additional reviews, the SNSOC formally rescinded the previous TS position and established a 1000 psig pressure requirement for the PORV accumulators. The 1000 psig criteria was selected as a conservative criteria until a TS license amendment could be developed and submitted to the NRC.

- On October 25, 1995, proposed TS changes were submitted to the NRC to resolve confusion over PORV operability requirements.

During this inspection period, the inspectors reviewed the current requirements for maintaining PORV's accumulator nitrogen pressure and the proposed TS changes. The proposed changes clearly stated that the PORVs were considered inoperable when the nitrogen supply was not available, since the nitrogen supply was the safety related motive force for the PORVs. The changes further stated that the existing TS 3.4.3.2 did not provide appropriate actions to be taken for an inoperable backup nitrogen supply system, because it required that when the PORVs were inoperable, the associated block valves should be closed. The proposed TS changes addressed this issue by clarifying action statement requirements.

The inspectors discussed the current positions with station management. Managers indicated that the PORVs would be considered inoperable when nitrogen pressure in the accumulators fell below 400 psig. This pressure was calculated based on using the PORVs to mitigate the consequences of an SGTR event with a loss of off-site power. No other accidents were considered when calculating the required pressure because the SGTR was the only accident requiring the PORVs for mitigation in the licensee's UFSAR accident analysis.

Based on the above information, the inspectors concluded the following: First, the basis for the licensee's response to and implementation of GL 90-06 requirements were not well understood and resulted in confusing and conflicting documentation regarding the PORV's licensing commitments and TS requirements. Second, corrective action regarding the April 11, 1994, DR was non-conservative and a more conservative approach was not implemented until December 5, 1994, two days after the TS change was implemented. The inspectors reviewed these facts and concluded that they overall represented a weakness by the licensee in understanding and implementing GL 90-06 requirements.

4.2.2 (Closed) IFI 50-338/95-20-01: Service Water Pump Cavitation Issue.

This item involved a concern relating to a cavitation noise emanating from pump 1-SW-P-1A. At the previous inspection period's end, the licensee was continuing to evaluate the noise's implications on long-term pump operability.

On December 1, the licensee employed divers to inspect the pump internals which were submerged in the SW reservoir. The divers found that the pump's impellers contained surface degradation which was the likely cause for the cavitation noise. However, this degradation was judged to be not an immediate operability concern. This evaluation was supported by the pump's vendor who reviewed the inspection results and supplied the licensee with an evaluation stating that the pump could continue to perform its designed functions for at least another year. The inspectors reviewed the inspection results and found the conclusions to be appropriate.

On December 3, the licensee satisfactorily performed a full flow head curve verification for the pump. The test was performed using 1-PT-75.2A.1, Service Water Pump (1-SW-P-1A) Head Curve Verification, revision 5-P2. The inspectors reviewed the test results and verified that the pump's ability to perform its design functions had been adequately demonstrated.

Based on the results of the licensee's inspection and test, the inspectors concluded that pump's continued operability had been adequately demonstrated. The inspectors noted that the licensee was continuing to pursue long term corrective action by planning to repair or replace the pump within the next year.

No violations or deviations were identified.

5.0 PLANT SUPPORT (71750)

Plant support activities were observed and reviewed to ensure that programs were implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. Activities reviewed included radiological controls, physical security, emergency preparedness, and fire protection.

5.1 Discovery of Old Blasting Wires Within the Protected Area

On December 1, the licensee informed the inspectors that site services workers excavating for new site power cables had unearthed two sets of blasting wires. The excavation was immediately stopped, and compensatory actions were taken by station security. The area was barricaded, and the wires were grounded while a plan could be developed for further action. The inspectors responded to the scene and observed that the two sets of wires appeared to be coming from old blasting holes used during plant construction. The nearest safety-related equipment to the location was observed to be the EDG underground fuel oil storage tanks, which were approximately 20 yards away.

Later the same day, the licensee obtained the services of a local blasting company to evaluate the situation. A technician from the blasting company tested the wires and found an open circuit. The technician also observed that the holes had the appearance of a previous blast taking place. Finally, the technician observed that if as much as twenty years had elapsed since blasting had taken place during the plant's original construction, any explosives left from that time would pose no hazard.

Based on the technician's recommendations, the licensee cut the wires, completed the electrical cabling work, and refilled the excavation. The inspectors reviewed the licensee's actions, including the report from the blasting company technician, and concluded that the problem had been appropriately resolved by the licensee.

No violations or deviations were identified.

6.0 Other NRC Personnel on Site

On November 29 and 30, the NRC Branch Chief, Mr. G. A. Belisle visited the site. Mr. Belisle toured the plant and met with licensee management and the inspectors to discuss plant status and current issues at the facility.

7.0 EXIT

The inspection scope and findings were summarized on December 21, 1995, by Mr. R. D. McWhorter, with those persons indicated by an asterisk in paragraph 1. An interim exit was conducted on December 8. The inspectors described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description and Reference
VIO	50-339/94-13-01	Closed	Failure to Use Procedure for Transformer Maintenance (paragraph 3.6.2).
URI	50-338, 339/94-30-01	Closed	PORV Nitrogen Accumulator Requirements (paragraph 4.2.1).

Type	Item Number	Status	Description and Reference
LER	50-339/95-03	Closed	Inoperable Containment Personnel Air Lock Outer Door Due to Open Personnel Hatch Vent Valve (paragraph 3.6.1).
LER	50-339/95-04	Closed	Automatic Reactor Trip Due to Loss of "B" Control Rod Drive Motor Generator Set (paragraph 2.8).
IFI	50-338/95-20-01	Closed	Service Water Pump Cavitation Issue (paragraph 4.2.2).

8.0 ACRONYMS

CFR	CODE OF FEDERAL REGULATIONS
DR	DEVIATION REPORT
EDG	EMERGENCY DIESEL GENERATOR
EHC	ELECTRO-HYDRAULIC CONTROL
ESF	ENGINEERED SAFETY FEATURE
GL	GENERIC LETTER
IFI	INSPECTION FOLLOWUP ITEM
IV	INDEPENDENT VERIFICATION
LER	LICENSEE EVENT REPORT
LCO	LIMITING CONDITION FOR OPERATION
MG	MOTOR-GENERATOR
MOV	MOTOR-OPERATED VALVED
NO.	NUMBER
NOV	NOTICE OF VIOLATION
NRC	NUCLEAR REGULATORY COMMISSION
OP	OPERATING PROCEDURE
PORV	POWER OPERATED RELIEF VALVE
psig	POUNDS PER SQUARE INCH GAUGE
QA	QUALITY ASSURANCE
QC	QUALITY CONTROL
RCE	ROOT CAUSE EVALUATION
RFO	REFUELING OUTAGE
RSST	RESERVE STATION SERVICE TRANSFORMER
SGTR	STEAM GENERATOR TUBE RUPTURE
SNSOC	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SOV	SOLENOID-OPERATED VALVE
SV	SIMULTANEOUS VERIFICATION
SW	SERVICE WATER
TDAFW	TURBINE-DRIVEN AUXILIARY FEEDWATER
TS	TECHNICAL SPECIFICATION
URI	UNRESOLVED ITEM
UFSAR	UPDATED FINAL SAFETY ANALYSIS REPORT

VHP	VESSEL HEAD PENETRATION
VIO	VIOLATION
WO	WORK ORDER
WR	WORK REQUEST