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

Report Nos.: 50-338/92-03 and 50-339/92-03

Licensee: Virginia Electric & Power Company
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: January 12 - February 15, 1992

Inspectors: [signature] 3/10/92
M.S. Lesser, Senior Resident Inspector Date Signed

[signature] 3/10/92
D.R. Taylor, Resident Inspector Date Signed

Approved by: [signature] 3/10/92
P.E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: operations, maintenance, minor modifications, surveillances, evaluation of licensee self-assessment, and decay heat removal reliability. Inspections of licensee backshift activities were conducted on the following days: January 18, 27, 29 and February 10, 1992.

Results:

In the area of operations, two examples of violations were identified where auxiliary operators failed to follow procedures. The first resulted in de-energizing a 120 volt vital AC bus and the second resulted in a valve being left out of its normal position (para 3.a and 3.b).

In the area of engineering/technical support, the licensee failed to provide a timely resolution to a 1990 Westinghouse Bulletin which identified a concern that the RHR relief valves may not be able to relieve rated capacity. About two years had elapsed before the operability concern of the RHR system was adequately addressed (para 3.c).

In the area of safety assessment/quality verification, the licensee's independent review program was determined to be effective. The licensee's industry operating experience review program effectively analyzed industry issues and developed a good action plan. However, weaknesses were identified

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in tracking action plan items and providing oversight to assure that priorities are maintained (para 8).

In the area of maintenance, good coordination of work and corrective action was observed with the overhaul of several service water isolation valves (para 5.c).

In the area of maintenance, effective use of the valve packing extraction tool was observed during re-packing activities. The tool reduces personnel exposure by allowing the old packing to be easily and quickly removed. (para 4.b).

In the area of safety assessment/quality verification, the licensee demostrated a high level of sensitivity and attention towards risk associated with unit shutdown evolutions. The licensee's programs provide high reliabilty for adequate decay heat removal (para 7).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Bowling, Manager, Nuclear Licensing and Programs
L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager, Operations and Maintenance
J. Hayes, Superintendent of Operations
D. Heacock, Superintendent, Station Engineering
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
W. Matthews, Superintendent, Maintenance
*J. O'Hanlon, Vice President, Nuclear Operations
D. Roberts, Supervisor, Station Nuclear Safety
D. Schappell, Superintendent, Site Services
R. Shears, Superintendent, Outage Management
*J. Smith, Manager, Quality Assurance
A. Stafford, Superintendent, Radiological Protection
*J. Stall, Assistant Station Manager, Nuclear Safety and Licensing
*W. Stewart, Senior Vice President, Nuclear

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

NRC Resident Inspectors

*M. Lesser, Senior Resident Inspector
*D. Taylor, Resident Inspector

*Attended exit interview

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

2. Plant Status

Unit 1 was maintained in a cold shutdown, mode 5 condition, during the entire inspection period.

Unit 2 began the inspection period at 100 percent power. On January 13, RCS boron concentration reached less than one PPM and a power coastdown was commenced. On January 29, with the unit at 89 percent power, the "C" FRV closed due to a driver card failure causing a reactor trip. Mode 1 was re-entered on January 30. The unit remained at power in a power coastdown for the remainder of the inspection period.

3. Operational Safety Verification (71707)

The inspectors conducted frequent visits to the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operational safety and compliance with TS and to maintain awareness of the overall operation of the facility. Instrumentation and ECCS lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. DRs were reviewed to assure that potential safety concerns were properly addressed and reported. Selected reports were followed to ensure that appropriate management attention and corrective action was applied.

a. Inadvertent Loss of Vital Bus I-II

On January 21, an auxiliary operator assigned to transfer bus I-IV to its regulating (Sola) transformer, inadvertently transferred bus I-II, which resulted in deenergizing the I-II 120 volt AC vital bus. The bus was restored to service six minutes later and DR 92-160 initiated to document the event. Because of plant conditions at the time of the transfer, no significant operational impact resulted.

The event occurred while performing 1-OP-26.5, 120 Volt Vital Bus Distribution. The test group had requested the I-IV 120 volt vital bus be transferred to its Sola transformer because of difficulties experienced when establishing a charge on battery I-IV following a service test.

In order to transfer a 120 volt vital AC bus from its inverter to the Sola transformer, the transformer must be energized by closing its associated breaker. The vital bus transfer can then be made, otherwise the vital bus would be transferred to a dead source. For this event, the auxiliary operator energized the Sola transformer associated with vital bus I-IV, but went to the incorrect transfer switch panel to complete the transfer. This resulted in placing the 120 volt vital AC bus I-II on a dead source.

The inspectors reviewed the procedure and examined the transfer switch panels associated with the event. The transfer switches for vital buses I-II and I-IV are physically separated by a door and both are well marked. Although the procedure provides instructions for all four vital buses, instructions for each bus are separated, with sufficient notes and cautions. The error appeared to be an example of operator inattention to detail, and failure to follow the licensee's self-check philosophy. The licensee's evaluation identified some deficiencies on behalf of the auxiliary operator regarding weak component identification techniques, and a lack of application of system knowledge to the intent of the procedure.

The inspectors reviewed this example of failure to follow procedure in light of extensive corrective action taken by the licensee for previous violations of this nature (50-338, 339/91-10-01, 50-338/91-26-01 and LER 50-339/91-10). The inspectors considered it reasonable to expect that this example should have been prevented. This issue is, therefore, identified as one example of a violation of TS 6.8.1 involving failure to follow procedures. Violation 50-338/92-03-01: Failure to Follow Procedures Resulting in Loss of Vital Bus and Mispositioned EDG Exhaust Valve.

b. Mispositioned EDG Exhaust System Valve

On January 25, the 1J EDG was being returned to service following several days of maintenance. Following the operability test of the engine, an operator initiated 1-OP-6.5A, 1H and 1J EDG Post Operational Check, to align the system for automatic operation. Step 5.4.4.e requires the operator to open and lock the EDG exhaust muffler bypass valve. The rest of the procedure was completed and the engine was declared operable, but the operator failed to accomplish this step. During a routine tour of the area four hours later, the Unit 1 Safeguards Area Watch identified the mispositioned valve and the condition was corrected.

The licensee reviewed the incident and determined that the operator initialled the steps to open and lock the muffler bypass valve prior to performing the task. He then became distracted when a second operator arrived to assist with rolling the engine in order to remove oil from the upper cylinders. The procedure was completed without going back and opening the muffler bypass valve. The licensee subsequently revised the procedure to require independent verification of this particular step. The licensee counseled the operator on the poor practice of initialling steps prior to accomplishment.

EDG exhaust is diverted through the muffler during testing to reduce noise, however, the muffler is not missile protected and must be bypassed when the engine is required to be operable. Therefore, during the period in question, the EDG would have been susceptible to tornado generated missiles.

Similar to the example discussed in paragraph 3.a, the inspectors determined that this problem should also have been prevented by previous corrective action. As such, this issue is identified as a second example of violation 50-338/92-03-01, Failure to Follow Procedures Resulting in Loss of Vital Bus and Mispositioned EDG Exhaust Valve.

The inspectors reviewed further the operation of this valve. The UFSAR section 9.5.8 states "a fully opened indicator will be attached to the valve-operating chain to ensure that the valve is in the correct (fully opened) position during normal operation." The inspectors determined that none of the chains on the four EDG's had any such indicator. This, however, had previously been identified by the licensee as a discrepancy on May 9, 1991. The inspectors reviewed licensee corrective action and noted that the proposal was simply to revise the UFSAR to describe actual plant configuration rather than place an indicator on the chain. The inspectors discussed the need for an indicator on the chain. The licensee decided to paint the chain at the point of locking the valve open and to provide a placard explaining the position indicator.

c. Potential for RHR System Overpressurization

On January 22, the licensee reported to the NRC that the RHR suction relief valves might not pass sufficient flow to protect the RHR system from a design basis overpressurization scenario when it is lined up to the RCS, and the LTOP system is not in service. Operating procedures do not place the LTOP system in service simultaneously with the RHR system during plant cooldown and, therefore, the units have been exposed to this vulnerability in the past.

The vulnerability scenario involves a charging/letdown flow mismatch which could be caused by a loss of instrument air while using the RHR system. This would cause the pressurizer to fill solid and the ensuing pressure excursion would challenge the relief valves. The RHR system is restricted to operate at less than 350°F and 450 psig. The piping is designed for 600 psig. The two RHR suction relief valves would begin to discharge at 467 psig and are supposed to pass 900 gpm each at 514 psig (10 percent relief valve accumulation). Although the relief valves are designed to pass the design basis flow rate, they are prevented from doing so by choking in the relief valve discharge piping to the PRT due to flashing of the hot water.

The LTOP system utilizes the pressurizer PORVs to protect the RCS from overpressure below 261°F on Unit 1 (340°F on Unit 2). The LTOP system, in conjunction with the TS requirement to have a maximum of one operable charging pump below 324°F on Unit 1 (340°F on Unit 2), provides the additional protection needed to prevent RHR overpressurization. However, between temperatures of 261 and 350°F on Unit 1 (340-350°F on Unit 2), the system is not adequately protected.

In order to address the issue in the short term, the licensee initiated Standing Order 185, RHR system Isolation Restrictions, with instructions to maintain the RHR system isolated from the RCS and use steam generators to cool the reactor temperature to below 324°F on Unit 1 (340°F on Unit 2). Additionally, the standing order would require LTOP to be placed in service any time the RHR is unisolated.

Since the AFW system is designed to cool the plant to 350°F, the inspectors questioned whether sufficient water inventory would exist under design basis conditions to cool the plant to a lower temperature. On January 31, Revision 1 to Standing Order 185 was implemented to ensure availability of a sufficient inventory of cooling water by administratively maintaining the ECST minimum level to 99 percent.

The licensee performed a safety evaluation under JCO 92-01 for the standing order. The JCO will remain in place until a TS amendment is approved. The inspectors reviewed the JCO along with RII management and NRR personnel and determined it to be acceptable for continued operation.

The RHR overpressurization concern was formally identified to the licensee by a Westinghouse bulletin, dated February 21, 1990. The inspectors questioned the length of time it took to evaluate and identify the need for corrective action and the lack of an operability determination until January 22, 1992. This letter was received and screened by the licensee's corporate IOER group and evaluated as an urgent priority item (highest level). The analysis report was completed within 30 days, as required by the priority, and outlined an action plan for engineering department to address the concern. The inspectors' review of documents indicated the requested completion date of September 10, 1990. An engineering manager's scoping committee meeting extended the due date to December 31, 1990. Apparently this date was changed a few days later to December 31, 1991 without knowledge or approval of the engineering managers scoping committee. The latter due date was provided to the IOER group for tracking status. In parallel with the corporate engineering review, the station received a draft version of the Westinghouse bulletin and initiated DR 90-162 on January 31, 1990. On June 21, 1990, after three extension requests, station engineering incorrectly evaluated the issue to be of no concern at North Anna. The evaluation only reviewed the design capacity of the relief valves and failed to consider the discharge piping backpressure, although this was clearly stated in the bulletin as a primary concern. Related to this issue, the inspectors were concerned with the following weaknesses:

1. Although there was reason to believe the RHR relief valves may not be capable of achieving design rated capacity nor be able to limit pressure excursions below ASME code limits as early as February 1990, operability of the system was not questioned by the licensee until January 22, 1992.

2. Engineering management controls over priorities and due dates reflected an apparent lack of sensitivity regarding the potential significance of the issue. The licensee's Potential Problem Report System, as described in the QA Topical Report, is used to perform detailed, multidiscipline reviews of complex design concerns. In this case one was not initiated until January 20, 1992. It appears that the Potential Problem Reporting process was not effectively implemented to promptly evaluate the design concern.

3. The IOER group failed to question the due dates for completion of action items by engineering considering the requirements of 10CFR50, Appendix B for prompt corrective action for conditions adverse to quality.

4. Station engineering's evaluation of the issue was inadequate in that it failed to consider the primary concern raised. Additionally, it appeared that station engineering and corporate engineering worked on the issue independently with little or no communication between the two.

5. Once operability was questioned, engineering support for proposed compensatory measures was less than effective in that the need for additional administrative controls on AFW inventory was not identified until questioned by the inspectors.

10 CFR 50, Appendix B, Criterion XVI, requires that measures be established to assure that conditions adverse to quality be promptly identified and corrected. As stated in the licensee's QA Topical Report, these measures are implemented by the DR and Potential Problem Report Systems. This issue is identified as a failure to provide prompt corrective action to a potentially inadequate RHR relief capacity. Violation 50-338,339/92-03-02: Untimely Corrective Action for Potential RHR Overpressure Relief Inadequacy.

d. Unit 2 Reactor Trip

Unit 2 experienced an automatic reactor trip on January 29, from 89 percent power due to low SG C water level (25 percent) coincident with steam flow greater than feed flow. All safety systems functioned normally and no complications occurred. The trip resulted when the C FRV failed closed after a control circuit driver card fault. The licensee has identified failure of these driver cards to be a recurring problem and most recently contributed to reactor trips in September 1991 (LER 50-339/91-09) and January 1990 (LER 50-338/90-01).

As a result of previous failures, the licensee initiated a PM to replace driver cards on a 5 year frequency, however, this may not be sufficient in that the last two failures involved cards with only 12-15 months of service. The licensee has also initiated a module repair program to try to increase the reliability of the cards.

The inspectors attended the licensee's post-trip review and found it to be thoroughly conducted. Minor equipment failures were identified during the trip and included several stuck open feedwater relief valves, excessive N-35 IRNI compensating voltage, EH DC power supply failure and a loop delta-T control circuit malfunction. The licensee identified and prioritized all restart issues. The licensee is continuing to evaluate the recurring failures of driver cards.

Two violations were identified.

4. Maintenance Observation (62703)

Station maintenance activities were observed/reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TS requirements.

a. N-35 IRNI Compensating Voltage

Following the Unit 2 reactor trip of January 29, the N-35 IRNI was identified as potentially having excessive compensating voltage as the instrument indicated off-scale low while the redundant channel N-36 IRNI indicated a value. The inspectors witnessed licensee actions to resolve the problem. Nuclear Instrument Channel Functional Test, 2-PT-30.1, was used to test the channel response and no problems were identified. The compensating voltage was checked and it corresponded to the expected value. The licensee verified detector operability by reducing compensating voltage and observing an instrument response. After this check, the voltage was returned to the previous setting.

Discussion between instrumentation personnel and operators indicated the problem only appeared at the low end of the scale. The licensee determined that the instrument remained operable; however, a minor adjustment in compensating voltage may be necessary. Licensee procedures require that this be done within 60 minutes of a reactor shutdown and since this window was missed, it will be performed at the next opportunity.

b. Valve Repacking

The inspectors witnessed a valve repacking activity on 1-CH-368 per Work Order 5900139299. The valve is a two-inch manual isolation valve located inside containment. The inspectors attended the pre-job briefing conducted by health physics personnel. The repack involved the use of a packing extraction tool which produces a jet of high pressure water directed on the old packing. The jet essentially cuts through the installed packing, hits the backseat, and forces the old packing out.

The technique significantly reduces the time for removing packing, thus is effective in maintaining dose rates ALARA. The inspectors noted good radiological control practices. The tool operator used a wet suit, facial shield and the operation was contained within a glove bag. The inspectors noted one problem with the packing control form. The packing control form provides a packing ring installation sequence and designates the number of packing rings; however, an additional wiper ring was necessary to prevent the gland follower from bottoming out. The procedure allows for this, which appears to compensate for incorrect packing control forms. The inspector determined that QA identified a similar concern in November 1991 as a result of a packing failure event which required a unit shutdown. The licensee has taken action to improve the valve packing program including applying additional resources to the packing control forms and implementing an industry study regarding improved packing techniques.

No violations or deviations were identified.

5. Minor Modifications (37828)

a. Piping Hydrostatic Test

The inspectors witnessed hydrostatic testing of newly installed piping, per DCP 90-12, in the service water radiation monitoring system. The function of the system is to sample service water down stream of the RSHX to detect a potential heat exchanger leak and mitigate a radioactive release to the environment. The 3/4 inch carbon steel sample piping was susceptible to micro-organism fouling. The DCP replaced the piping with 1 1/2 inch stainless steel. The inspectors observed the piping associated with sample pump 1-SW-P-5 and RSHX 1A being tested to 110 percent of design pressure. The ANI inspector and QA were present and walked down the piping with weld drawings. One discrepancy was identified where a weld was not properly labelled on the drawing. The QA inspector stated that a DR would be written to identify and correct the error. No problems were identified with the hydrostatic test.

b. Pressurizer Heater Cable Replacement

EWR 90-280 was implemented on Unit 1 to address chronic problems with pressurizer heater tripped circuit breakers and blown fuses due to component overheating (refer to IFI 50-338/91-06-03). The modification involved replacing the cable between the electrical penetration terminal boxes and the circuit breaker panels and the cable inside containment between the electrical penetration and the heater junction boxes with a higher amperage cable, and replacing circuit breakers with temperature compensated breakers and installing fuses with higher ampere ratings. Additionally, cabling was removed from existing conduit and installed in cable trays with louvered tray covers for improved ventilation.

The inspectors observed work in progress and reviewed the modification safety evaluation and 10 CFR 50, Appendix R design impact checklist. The evaluations appeared to be thorough and the modification should improve reliability of the system. Additional maintenance has brought the number of operable heaters up to 76 out of 78.

c. Service Water System Valve Overhauls

As a result of recurring problems with RSHX service water isolation valves 1-SW-MOV-103/104 A-D, the licensee decided to inspect and rebuild the valves to reduce high seating torque. Upon tear-down and inspection, several problems were identified with one or more of the valves which required engineering support to resolve. The problems included: deteriorated valve stem bushings, loose pinning of valve disc to the stem, off-center valve discs, worn thrust collars, brittle packing, excessive valve seat wear, and insufficient fit between shaft bushings and valve body bore. The licensee developed DCP 92-104 to modify the valves to address the concerns. The vendor was consulted to obtain an improved packing arrangement.

The licensee expanded the scope of the work to include Service Water Header Isolation and Cross-Connect Valves 1-SW-MOV-101/105 A-D and 1-SW-MOV-102/106 A-B. This required two service water header outages and entry into TS action statements. The licensee effectively planned the work by first refurbishing the cross-connect valves (outside the LCO) and then, being the same type as the isolation valves, reinstalling them as the isolation valves (within the LCO) to minimize the time duration in the action statement. The inspectors noted good coordination between engineering, maintenance and operations for the entire effort. Corrective action appeared to be extensive in addressing identified problems and in expansion of the initial work scope.

6. Surveillance Observation (61726)

The inspectors observed/reviewed TS required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCO's were met and that any deficiencies identified were properly reviewed and resolved.

On January 16, the inspectors observed the performance of 2-PT-82.3A, 2H EDG Test (Simulated Loss of Offsite Power in Conjunction with an ESF Actuation Signal). The test verifies that the EDG reaches rated speed, voltage and frequency within the TS limit of 10 seconds, and can be loaded to 2500-2600kw within 60 seconds.

During the fast start, a chart recorder is used to plot EDG voltage and frequency. The input to these measurements are obtained through an AC to DC voltage converter and a frequency converter before being connected to channel one and two of the chart recorder. The inspectors noted that the converters were not calibrated instruments, but rather checked by calibrated instruments prior to each use. The inspectors questioned this practice since misalignment of the recorder could represent a significant error. Upon discussion with the technicians installing the equipment, the inspectors were informed that the voltage and frequency ranges are programmed into the chart recorder in the shop prior to the equipment being brought to the control room for testing. The chart recorder was set for a range of 95-145 volts, which is scaled down from actual measured voltage by a factor of 35. To demonstrate that the chart recorder was set up to measure voltage at 95-145 volts, the licensee measured input voltage using a calibrated instrument and verified that the output of the chart recorder accurately reflected the input voltage. The strip chart was reading between 3-4 volts low for the input applied. This represented a 105-140 volts error when considering the 35 to 1 ratio for the voltage measurement. The acceptable range for the diesel generator is 4160 +/- 420 volts.

The inspectors discussed this matter further with licensee management, who pointed out a third data plot provided by the chart recorder. This plot provided direct input of frequency and voltage and is not dependent on paper alignment. Also, the chart recorder is a calibrated instrument with respect to speed and voltage. Since the chart recorder is plotting cycles, the frequency can be determined by counting the cycles over a period of time and voltage can be determined by measuring the peak-to-peak value. The paper alignment does not affect these measurements. This plot serves as a check of the line plots obtained from connections one and two. The inspectors were further informed that the I&C technicians are required to perform a one point check prior to and after each test. However, this check is not procedurized and the licensee acknowledged that only about half of the technicians perform the check. The licensee informed the inspectors that a change to the procedure was pending which would provide more detailed instructions for connecting the test equipment and performing checks prior to and after each use.

7. Reliable Decay Heat Removal During Outages (TI 2515/113)

The inspectors reviewed licensee programs to ensure reliable decay heat removal capability during plant outages. Implementation of requirements and the conduct of certain activities during the current Unit 1 steam generator inspection outage were reviewed for adequacy. The inspectors found the licensee's programs indicative of a high level of sensitivity towards safe and reliable operations during shutdown conditions. Programs in place or currently being developed are adequate to ensure that outage activities which have the potential to affect decay heat removal, are properly reviewed and approved by management. The licensee has established procedures to ensure that decay heat removal is maintained under forced and natural circulation conditions. Several examples were identified which illustrated the licensee's conservative approach towards shutdown operations.

a. Shutdown Safety Assessment

The licensee has identified a group of critical safety functions while shutdown. These include reactivity, core cooling, electrical power availability, containment, water inventory and RCS integrity. For each critical safety function an unacceptable condition is defined and a polygon with a critical safety function at each point is developed to graphically illustrate the current margin available. This is reviewed by management on a daily basis in addition to a projected polygon for the next day.

The licensee has recently expanded the review by developing a status tree for each critical safety function. As an example, the inputs for the electrical power availability function include: number of EDGs available, number of offsite power sources available and no switchyard work in progress. Points are assigned for each operable input and totaled. The resulting condition is a status tree color coded red, orange, yellow or green. A green path indicates the highest level of safety. The outage planning policy is that no red or orange paths will be entered intentionally during an outage. A red path is unacceptable and an orange path would require a contingency plan and management approval to remain active.

b. Cold Shutdown Inventory Balance

NSE ADM-12, STA Responsibilities, requires the STA to perform an inventory balance of the RCS once per shift when temperature is less than 200°F. The purpose of the inventory is to identify a source of leakage from the system. The calculation is based on the assumption of a zero leakage condition, and thus the net change over time in all system tank levels equals zero. The tanks of concern are the pressurizer (or reactor vessel), volume control tank, primary drains transfer tank and gas stripper. The calculation with the use of a computer spreadsheet considers temperature changes, RCS additions from the CVCS system and additions from loop stop valve disc pressurization. The STA is also required to observe RVLIS and containment sump pumping frequency for unexplained changes. The program is not intended to be a "cookbook" calculation but to encourage investigation of the current plant conditions. The calculation may be modified to account for various system configurations and is considered effective in identifying adverse trends.

c. Electrical Power Availability

The licensee's TS for modes 4 and 5 require one source of offsite power, one EDG, one train of 4160 and 480 volt busses and two of four vital 120 volt AC busses. Additionally, two of four 125 volt DC busses and associated battery and chargers are required to be operable. The licensee's maintenance planning goal is to have at least two offsite power sources and one EDG available when fuel is in the reactor vessel. Maintenance and testing will be planned on only one train at a time. Electrical switchyard activities will be coordinated to ensure that none are conducted during times of reduced inventory.

The inspectors reviewed the electrical lineup on Unit 1 during the recent vital battery I-IV replacement. Although not required to be operable by TS, the licensee took actions to assure power was available to 125 volt DC panel I-IV and 120 volt vital AC panel I-IV. The 120 volt vital bus was disconnected from its inverter and powered from its backup source, the Sola transformer. Also, the 125 volt DC panel I-IV was cross-tied to 125 volt DC panel I-III to provide a battery backed source. The inspectors determined that this electrical lineup was specified in the design change package and appropriately approved.

The inspectors also reviewed licensee activities during recent EDG battery replacements. In each case the EDG was appropriately declared inoperable when the battery was inoperable.

c. Valve Maintenance on Non-Isolable System

The inspectors reviewed DR-92-63, that reported a primary system leak that occurred when the packing of 1-CH-320, Letdown Line Manual Isolation Valve, blew out during repacking maintenance activities. The unit was in mode 5 at the time. The two-inch valve is non-isolable from the RCS and the licensee historically backseats the valve to repack it. In this case the leak developed when the packing above the lantern ring was removed. It was not clear whether the valve was leaking past its backseat or backflow was occurring from the packing leakoff line. Nevertheless, while a loss of inventory was occurring, the mechanics exited containment and reported the leak to operations. Actions were then taken to stop the leak which involved tightening the valve on its backseat and reducing leakoff line backpressure.

The leak was minor in nature as no changes were observed in pressurizer level, however, a delay in stopping the leak resulted from a lack of operations involvement in the activities. The inspectors noted that a contingency plan had not been discussed and documented, nor had lines of communication been established between operations and maintenance. The inspectors pointed out that maintenance activities involving the potential to lose inventory, such as this, warrants increased planning attention. The licensee indicated they would consider additional support by operations for such evolutions and additional instructions in repacking procedures to ensure the lantern ring is aligned with the leakoff line.

8. Evaluation of Licensee Self-Assessment Capability (40500)

The inspectors conducted a review of the licensee's corporate independent review functions and industry experience program. TS 6.5.2.7 requires that the MSRC is responsible for the review of safety evaluations, unreviewed safety questions, TS changes, violations, significant abnormalities, LER's, deficiencies that could affect nuclear safety and SNSOC meeting minutes. The licensee implemented the requirements by submitting all LER's violations and TS changes to MSRC members for review.

Additionally, all safety evaluations are independently reviewed by CNS while performing its role as a subcommittee to the MSRC. CNS also reports to the Manager of Nuclear Licensing and Programs when conducting independent assessments of station activities and when implementing the IOER Program. The following administrative documents which describe the program were reviewed: LICP-4000 Corporate Nuclear Safety, LICP-2001 Independent Review Program, NLP ADM 4.1 Review and Processing of Industry Operating Experience Documents and VPAP 3002 Operating Experience Program.

a. Independent Review Program

Through this program CNS independently reviews all safety evaluations performed in accordance with 10CFR50.59 and reviews all SNSOC meeting minutes. The inspectors discussed the program with responsible personnel, reviewed selected independent verification packages for effectiveness and reviewed qualifications of individuals. Personnel assigned to perform the reviews appeared to collectively possess experience and competence in the diverse disciplines necessary to be effective. The program appeared to be clearly defined and independent reviews were conducted effectively. Mechanisms were available to identify and resolve concerns, and to track and report the status of items. The inspectors noted that while safety evaluations were reviewed, no requirement existed to independently review a sample of activity screening checklists (used to identify the need for a safety evaluation) to ensure that required activities received a safety evaluation. The licensee agreed to consider the need for this.

b. Industry Operating Experience Review

CNS is responsible for maintaining the licensee's IOER Program with the purpose of reviewing IOER documents to assess applicability and develop action plans necessary to prevent or minimize the consequences of industry events. IOER documents include NRC Information Notices, Generic Letters, Virginia Power LER's, 10CFR21 Notifications, INPO event reports and Westinghouse Technical Bulletins. IOER documents are initially screened within 10 days and assigned a priority to prepare an analysis report and develop an action plan within 30, 60, or 90 days to address the concern. The inspectors selected a sampling of documents and determined that appropriate priority had been assigned and that action plans were of high quality, clearly identifying the concerns and the need for further action. The inspectors identified weaknesses with the licensee's tracking system for documents in that in many cases due dates were not assigned or had been exceeded or proposed actions had been rejected with no indication that followup was being pursued. The inspectors determined that in general the actions were being adequately pursued and the problems were confined to maintenance of the tracking system data base. One concern was identified with tracking of a Westinghouse notification regarding the potential inadequacy of RHR system overpressure protection. (This issue is further discussed in paragraph 3.c and is the subject of Violation 50-338,339/92-03-02). In this case it appeared the IOER oversight of action item priorities and due dates was less than effective in that the timeliness of an operability determination and corrective action was not commensurate with the safety significance of the issue.

9. Exit (30703)

The inspection scope and findings were summarized on February 18, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
VIO 50-338/92-03-01	Failure to Follow Procedures Resulting in Loss of Vital Bus and Mispositioned EDG Exhaust Valve (para 3.a and 3.b)
VIO 50-338,339/92-03-02	Untimely Corrective Action for Potential RHR Overpresssure Relief Inadequacy (para 3.c)

10. Acronyms and Initialisms

AC	Alternating Current
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANI	American Nuclear Insurer
ASME	American Society of Mechanical Engineers
CNS	Corporate Nuclear Safety
CVCS	Chemical Volume Control System
DC	Direct Current
DCP	Design Change Package
DR	Deviation Report
ECCS	Emergency Core Cooling System
ECST	Emergency Condensate Storage Tank
EDG	Emergency Diesel Generator
EH	Electro Hydraulic
ESF	Engineered Safety Feature
EWR	Engineering Work Request
FRV	Feedwater Regulating Valve
I&C	Instrumentation and Control
IFI	Inspector Follow-up Item
INPO	Institute of Nuclear Power Operations
IOER	Industry Operating Experience Review
IRNI	Intermediate Range Nuclear Instrument
JCO	Justification for Continued Operation
KW	Kilowatts
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LTOP	Low Temperature Overpressure Protection
MSRC	Management Safety Review Committee
NLP	Nuclear Licensing Procedure
NRC	Nuclear Regulatory Commission

NRR	Nuclear Reactor Regulation
NSE	Nuclear Safety Engineering
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PPM	Parts Per Million
PRT	Pressure Relief Tank
PSIG	Pounds per Square Inch Gage
QA	Quality Assurance
RII	Region II
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RSHX	Recirculation Spray Heat Exchanger
RVLIS	Reactor Vessel Level Indicating System
SG	Steam Generator
SNSOC	Station Nuclear Safety and Operating Committee
STA	Shift Technical Advisor
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
VIO	Violation