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

Report Nos.: 50-280/88-14 and 50-281/88-14

Licensee: Virginia Electric and Power Company
Richmond, Virginia 23261

Docket Nos.: 50-280 and 50-281 License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: April 3-30, 1988

Inspectors: _____ 5-25-88
W. E. Holland, Senior Resident Inspector Date Signed

_____ 5-25-88
L. E. Nicholson, Resident Inspector Date Signed

Approved by: _____ 5/25/88
F. S. Cantrell, 2A Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, licensee event report review, and followup on inspector identified items.

Results: No violations or deviations were identified in this inspection report.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*D. L. Benson, Station Manager
H. L. Miller, Assistant Station Manager
*E. S. Grecheck, Assistant Station Manager
J. A. Bailey, Superintendent of Operations
J. W. Ogren, Superintendent of Maintenance
S. P. Sarver, Superintendent of Health Physics
R. H. Blount, Superintendent of Technical Services
R. L. Johnson, Operations Supervisor
J. A. Price, Site Quality Assurance Manager
*G. D. Miller, Licensing Coordinator, Surry

*Attended exit meeting

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

2. Exit Interview

The inspection scope and findings were summarized on May 2, 1988, with those individuals identified by an asterisk in paragraph 1. No new items were identified by the inspectors during this exit. The licensee acknowledged the inspection findings with no dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Plant Status

Unit 1

Unit 1 began the reporting period coasting down for the refueling outage. On April 8, the unit began a rampdown from approximately 75% power for refueling and was placed in cold shutdown on April 10. At the end of the inspection period the unit was in day 21 of the maintenance/refueling outage which was scheduled to last 55 days.

Unit 2

Unit 2 began the reporting period at cold shutdown while making repairs to the vital bus III inverter and troubleshooting indicated flow blockage in the auxiliary feedwater (AFW) line. The inspectors monitored the licensee actions regarding the AFW blockage as detailed in paragraph 7. The inverter was repaired and the unit achieved criticality at 7:32 pm on April 5, 1988. The unit resumed power operation on April 6 and operated at power for the remainder of the inspection period.

4. Licensee Action on Previous Enforcement Matters (92702)

(Closed) Violation 280; 281/88-01-02, Failure to provide adequate review or approval for replacement parts used in safety-related components. The subject violation involved the discovery of hand-made parts of incorrect material and size that contributed to the failure of valve 2-CH-MOV-2289B. No evaluation or documentation of approval could be produced regarding the defective parts. The licensee stated in their response to this violation, dated March 25, 1988, that significant upgrades in maintenance procedures and philosophies have occurred since the maintenance was performed on this valve. In addition, the licensee revised their administrative procedure regarding the subject. The inspector verified that the statement was added to the appropriate administrative procedure to require proper documentation from engineering prior to substitution of safety-related material. This item is closed.

(Open) Unresolved Item 280; 281/88-04-02, Licensee review of steam flow instrumentation accuracy with regards to operation and accident analysis at low power levels. The item was identified in inspection report 280; 281/88-04. The inspector observed during a startup of the Unit 1 reactor that steam flow indication was not available for operator information until the indicated power level reached approximately 18%. The inspector questioned the licensee with regard to whether steam flow instrumentation was providing indication within the design accuracy of the system at low power level. Also the inspector requested that the licensee review their accident analysis and operating procedures to evaluate if current low power indication of the instrumentation provides for appropriate automatic and/or operator actions during low power operation.

During this period the inspector was provided a copy of an engineering evaluation which concluded that waiting until approximately 25% power to apply channel check tolerance would have no impact on the existing safety analyses. The station safety committee reviewed this evaluation and implemented a requirement to verify steam flow indication prior to exceeding 25% power in operations procedure. The inspector reviewed this information and, based on different requirements at other power stations, has requested that further technical review be accomplished by other NRC offices prior to closing this item. This issue will remain open until these reviews are complete.

5. Unresolved Items

Unresolved items are matters about which more information is required to determine weather they are acceptable or may involve violations or deviations. No new unresolved items are addressed in this inspection report.

6. Plant Operations

Operational Safety Verification (71707)

The inspectors conducted daily inspections in the following areas: Control room staffing, access, and operator behavior; operator adherence to approved procedures, technical specifications, and limiting conditions for operations; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; review of control room operator logs, operating orders, plant deviation reports, tagout logs, jumper logs, and tags on components to verify compliance with approved procedures.

The inspectors conducted weekly inspections in the following areas: Verification of operability of selected ESF systems by valve alignment, breaker positions, condition of equipment or component(s), and operability of instrumentation and support items essential to system actuation or performance.

Plant tours which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, physical security controls, plant housekeeping conditions/cleanliness, and missile hazards.

The inspectors routinely monitor the temperature of the auxiliary feedwater (AFW) pump discharge piping to ensure steam binding is prevented. Elevated temperatures were noted at the pump discharge headers following the Unit 2 restart during this inspection period. The licensee monitors the local readout from strap-on thermocouple jackets installed on both AFW discharge headers each shift. Temperatures on the headers were observed on April 7 to be 145 and 200 degrees F with the steam-driven pump casing very hot to the touch. The licensee implemented a temporary operating procedure (2-TOP-2015, "Unit 2 Auxiliary Feedwater Check Valve Leakage Guideline") that was to determine which of the check valves were leaking by and causing the temperature rise. The results of this procedure indicates that although some paths are worse than others, it appears that all the check valves are subject to backleakage. The licensee has reviewed Generic Letter 88-03 dated February 17, 1988. The licensee has implemented the requirements to monitor fluid conditions within the AFW system and has since developed an abnormal procedure to be invoked when elevated temperatures are present.

The inspectors continued an active overview of all actions in this area. The inspectors conducted biweekly inspections in the following areas: Verification review and walkdown of safety-related tagout(s) in effect; review of sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation of the plant problem identification system; verification of selected portions of containment isolation lineup(s); and verification that notices to workers are posted as required by 10 CFR 19.

Certain tours were conducted on backshifts or weekends. Backshift or weekend tours were conducted on April 3, 25, and 29. Inspections included areas in the Units 1 and 2 cable vaults, Units 1 and 2 containments, vital battery rooms, steam safeguards areas, emergency switchgear rooms, diesel generator rooms, control room, auxiliary building, cable penetration areas, independent spent fuel storage facility, low level intake structure, and the safeguards valve pit and pump pit areas. Reactor coolant system (RCS) leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated; and that appropriate actions were taken, if required. The inspectors routinely independently calculated RCS leak rates using the NRC Independent Measurements Leak Rate Program (RCSLK9). On a regular basis, radiation work permits (RWPs) were reviewed and specific work activities were monitored to assure they were being conducted per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequency were verified.

In the course of monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages and vehicles; badge issuance and retrieval; escorting of visitors; and patrols and compensatory posts.

During a routine review of operational data, the inspector witnessed a temperature transient in the component cooling system (CC) that appeared to be a result of degraded station vacuum priming to the CC heat exchangers. The CC heat exchangers at this station consist of four shell and tube units, mounted horizontally, with one pass on each side of the heat exchanger. Component cooling water enters and exits the shell side through two 18-inch openings while the service water enters through a 30-inch opening and travels through copper-nickel tubes. The "A" and "B" heat exchangers are located at an elevation of approximately 25 feet above sea level with the "C" and "D" heat exchangers located directly underneath. Although all four heat exchangers are located in the Unit 1 turbine building basement, they may be aligned to support either unit. Technical Specifications require two heat exchangers to be operable for one unit operation and three exchangers operable for two unit operation.

The service water that flows through the tube-side is gravity fed from the intake canal that is required by Technical Specification to be maintained at a level 18 feet above sea level. Each service water side of the CC heat exchangers has a connection to the station vacuum priming system to aid in establishing service water flow. This vacuum system consists of one vacuum priming tank, three vacuum priming pumps and the associated valves and piping that are primarily used to support main condenser operation. No mention is made of the vacuum priming system in either the Final Safety Analysis Report (FSAR) or the Technical Specifications.

The inspector questioned the reliance of this non-safety related system to maintain adequate service water flow through the component cooling water heat exchangers. A rise in CC temperatures was corrected by blowing down the vacuum priming lines to the upper heat exchanger. Discussions with plant personnel and station management indicated that service water flow may degrade through the upper heat exchangers during certain allowable operating conditions (i.e., low canal level with warm service water). This situation is of particular concern during the current refueling outage when the canal level had been planned to be maintained low and the entire CC load carried by the two upper heat exchangers.

These concerns were identified by both the resident inspector and regional management to station management on May 4 and May 6, 1988, respectively. The licensee performed a design basis review that verified that the CC heat exchangers were designed to be fully operable without the aid of the vacuum priming system; however, it was also determined that the vacuum priming system is not seismically qualified upstream of the isolation valves located directly above the heat exchangers. All four CC heat exchangers were declared inoperable on May 20 and actions performed to close the vacuum priming isolation valves and return the seismic supports for the vacuum piping from the heat exchangers to the valves. These supports had been removed and missing for an unspecified period of time. The licensee also established an administrative low level limit of 27 feet in the intake canal. The licensee also provided a letter from Virginia Power to the NRC dated April 26, 1988, that stated that the component cooling water system can be operated at any intake canal level consistent with the Technical Specifications and that vacuum priming is not required for continued system operation following flow initiation. The inspector held further discussions with the licensee on this issue and it was agreed that the licensee would conduct a test of the system after completion of all work scheduled during the present Unit 1 outage on the portion of the service water system which provides for flow to the component cooling water heat exchangers. The test will verify that service water flow to the A and B component cooling water heat exchangers (upper) does not degrade at low canal levels with vacuum priming isolated. The resident inspectors are continuing to monitor the performance of the CC heat exchangers and will review the licensee's test results.

The inspectors monitored the licensee actions with regards to the failure of the primary system power operated relief valves (PORV) that occurred on April 15, 1988. While performing evolutions to take Unit 1 to cold shutdown for refueling in accordance with Operation Procedure 3.3, the reactor operator attempted to open the pressurizer PORV 1-PCV-1456. No indication of valve movement was noted with the main control board switch held in the open position for approximately 15 seconds. The switch was returned to the "auto" position and a similar attempt was made to open the other PORV, 1-PCV-1455C, with identical results. The operator tried a second time to open each valve and the valves responded correctly. The licensee identified this problem on station deviation S1-88-295, and made a 4-hour report to the NRC. The inspectors will monitor licensee evaluation and repair of the PORV's during the Unit 1 outage.

Engineered Safety Feature System Walkdown (71710)

The inspector performed a walkdown of the components that are identified as important in the risk-based inspection guide developed for Surry. This PRA-based guide (EGG-REQ-7746, "PRA Applications Program For Inspection At The Surry Nuclear Power Station", dated July 1987) was developed to enable the inspector to quickly focus on only those components that perform vital functions during accident sequences. The inspector used this modified checklist to perform walkdowns on both units. This verification also included the following: confirmation that the licensee's system lineup procedure matches plant drawings and actual plant configuration; hangers and supports are operable; housekeeping is adequate; valves and/or breakers in the system are installed correctly and appear to be operable; fire protection/prevention is adequate; major system components are properly labeled and appear to be operable; instrumentation is properly installed, calibrated, and functioning; and valves and/or breakers are in correct position as required by plant procedure and unit status.

Within the areas inspected, no violations or deviations were identified.

7. Maintenance Inspections (62703)

The inspector continued to follow the effort to locate an apparent blockage in the auxiliary feedwater (AFW) line to the "A" steam generator that was observed following the Unit 2 reactor trip on March 27, 1988. This issue was also discussed in Inspection Report 280; 281/88-09. Fibroscopic examination of the entire length of pipe from the AFW headers up to the point that AFW ties into the "A" main feed line revealed no obstruction. The licensee then disassembled and inspected all the motor-operated valves downstream of the AFW headers and found no contributor to blockage. However, the tack welds that secure the discs to the stem nuts were found to be cracked in three of the six valves. This item was reviewed by a region-based specialist and discussed in Inspection Report 280;281/88-12.

The AFW system was subsequently reassembled and retested using all possible flowpaths with each of the three pumps. Results of this testing indicated all parameters functioning normally with no indications of blockage noted. The results of the inspections and testing were closely monitored by the resident inspector and were the subject of several conference calls between station and NRC management. The licensee concluded that the apparent blockage was no longer present and the unit returned to power operations on April 5, 1988.

Outage related maintenance items (Unit 1)

During this inspection period, the residents selected several maintenance items for monitoring during the Unit 1 maintenance/refueling outage. They were:

- Auxiliary Feedwater System Repairs

  This area includes overhaul/repair of auxiliary feedwater motor operated valves and other work associated with the system. The area also includes overhaul of the Terry turbine which is the prime mover for the steam driven auxiliary feedwater pump. When the inspection period ended, the turbine had been disassembled and repairs were in progress on the rotor.

- Design Change 85-32, Vital Bus Upgrade (UPS)

  This area includes replacement of the Unit 1 DC vital power supply for the "A" bus including new batteries and solid state battery charger/inverter package. When the inspection period ended, the new power supply inverter/battery chargers and batteries were being installed.

- Recirculation Spray Heat Exchanger Replacement

  This area includes replacement of the four recirculation spray heat exchangers which are located in containment with new heat exchangers. The replacements were required due to degradation of the heat exchanger tubes (90/10 copper/nickel). The new heat exchangers have tubes made of titanium which is a more corrosion resistant material and should provide for a longer service life. At the end of the inspection period, the four old heat exchangers had been removed from containment and the new heat exchangers were being moved into position in containment.

- Overhaul of the Pressurizer Power Operated Relief Valves (1-PCV-1455C and 1-PCV-1456).

  The subject PORVs were scheduled for overhaul due to seat leakage during unit operation at power. The inspection period ended prior to troubleshooting of the PORV stroke problem identified in paragraph 6.

The review of the above items was ongoing when the inspection period ended. This review will be addressed in more detail in next month's inspection report.

Within the areas inspected, no violations or deviations were identified.

8. Surveillance Inspections (61726)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures as follows:

- Test prerequisites were met.

- Tests were performed in accordance with approved procedures.

- Test procedures appeared to perform their intended function.
- Adequate coordination existed among personnel involved in the test.
- Test data was properly collected and recorded.

Inspection areas included the following:

On April 3, the inspector witnessed portions of Periodic Test 1-PT-17.1, Containment Spray System, that verified operability of the containment spray pumps 1-CS-P-1A & B as required by Technical Specification 4.5. No discrepancies were noted.

On April 6, 1988, the inspector witnessed portions of the monthly operability test of the emergency diesel generator #3 per Periodic Test 1-PT-22.3C. The diesel started and carried the required load with no abnormalities. No discrepancies were noted.

On April 22, 1988, the inspector witnessed portions of testing to verify that the uncollected leakage from the safety injection system recirculation loop is within the requirements of Technical Specification Table 4.11-1. This test is performed each refueling in accordance with procedure 1-PT-16.10D, System Leakage Test For Safety Injection System - External Recirculation Loop. No discrepancies were noted.

The inspectors routinely monitored the licensee performance with regards to local leak rate testing of containment isolation valves to establish an as-found total containment leak rate. This testing is performed per procedure 1-PT-16.4, Containment Isolation Valve Leakage. During testing of penetration #70, it was discovered that containment isolation valve 1-RS-11 was being held in the open position. This valve is a 10-inch, 150 lb. weighted swing check valve manufactured by Schutte and Koertering. The weighted arm that is designed to hold the valve closed was found to be approximately eight degrees beyond top dead center, resulting in the valve being held in the full open position. The licensee examined the three other identical valves in Unit 1 (1-RS-17, 1-CS-13 and 24) and found that although they were being held in the full closed position, they had the potential to remain open once opened (once the weights had swung over top dead center). The licensee considered this situation to constitute a violation of containment integrity and reported it pursuant to the requirements of 10 CFR 50.72.b.2.i. An entry was made to Unit 2 containment that verified the corresponding valves in that unit are in the closed position. A final engineering evaluation and additional corrective action was being developed as the inspection period ended. The inspectors will continue to review this area during the next inspection period.

Within the areas inspected, no violations or deviations were identified.

9. Licensee Event Report (LER) Review (92700)

The inspector reviewed the LERs listed below to ascertain whether NRC reporting requirements were being met and to determine appropriateness of the corrective action(s). The inspector's review also included followup on implementation of corrective action and review of licensee documentation that all required corrective action(s) were complete.

LERs that identify violation(s) of regulation(s) and that meet the criteria of 10 CFR, Part 2, Appendix C, Section V shall be identified as Licensee Identified Violations (LIV) in the following closeout paragraphs. LIVs are considered first-time occurrence violations which meet the NRC enforcement policy criteria for exemption from issuance of a Notice of Violation. These items are identified to allow for proper evaluation of corrective actions in the event that similar events occur in the future.

(Closed) LER 280/87-24, Reactor Trip on Low Flow Due to Reactor Coolant Pump Trip. This report discussed the September 20, 1987, reactor trip on Unit 1 from 100 percent power due to low reactor coolant system flow. Approximately 35 seconds after the reactor trip, a high steam flow with low RCS Tavg safety injection occurred. The SI signal was only present for approximately 2 seconds and determined to be spurious. A low flow signal from the rector coolant pump trip was determined to be from the 'B' reactor coolant pump breaker tripping on an instantaneous ground fault. An engineering evaluation determined that the bus bar failure was caused by vibration of the unsupported length of feeder cable leads. The bus bars on A and C RCPs were visually inspected and meggered to verify their integrity prior to unit restart. The licensee has subsequently issued an engineering work request (EWR) to add cable restraints to the feeder cables of each motor during the present refueling outage. Similar work is scheduled on Unit 2 during its upcoming refueling outage. The inspector reviewed the EWRs and monitored progress during the Unit 1 refueling outage. This LER is closed.

(Closed) LER 280/87-33, Charging Pump Component Cooling Water System Inoperable Due to Inadequate Test Procedure. The issue involved improper venting of the subject system after testing of a system component. This condition resulted in both charging pump component cooling pumps becoming air bound and inoperable. Immediate corrective action included venting of the system and restarting a charging pump component cooling pump to restore flow. Additional corrective action to prevent recurrence was in the form of a revision to Periodic Test (PT)-53.1B, "ASME Hydrostatic/ Pneumatic Pressure Tests" to include detailed instructions for depressurizing and venting of systems at completion of testing. The inspector reviewed the revised procedure, revision dated April 21, 1988. This item is identified as a LIV (280/88-14-01) for failure to provide adequate procedure for restoration of a system after testing. This LER is closed.

10. Followup on Inspector Identified Items (92701)

(Closed) Inspector Followup Item (IFI) 280; 281/87-28-01, Review Corrective Actions For Grinnel Valves. This item was opened following the failure of the primary drain header isolation valve, 1-DG-14, during the failed loop stop valve packing event described in LER 87-13. This valve type utilizes a rubber diaphragm that tend to deteriorate with age and is used extensively throughout the station. The inspector reviewed the licensee program to periodically replace the diaphragms as well as the specific corrective actions for 1-DG-14, which involved changing it to a ball-type valve. This item is closed.