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

Report Nos.: 50-280/93-30 and 50-281/93-30

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

Docket Nos.: 50-280 and 50-281

License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: December 5, 1993 through January 1, 1994

Inspectors:

Larry Garner For — 1/26/94
M. W. Branch, Senior Resident Inspector — Date Signed

Larry Garner For — 1/26/94
J. W. York, Resident Inspector — Date Signed

Larry Garner For — 1/26/94
S. G. Tingen, Resident Inspector — Date Signed

Approved by: G A Belisle — 1/26/94
G. A. Belisle, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance inspections, balance of plant inspections, review of plant modifications, and action on previous inspection items. While performing this inspection, the resident inspectors conducted reviews of the licensee's backshifts, holiday or weekend operations on December 10, 12, 19, 22, and 28, 1993.

Results:

Operations functional area:

Adequate implementation of the freeze protection program was noted (paragraph 3.b).

Maintenance functional area:

Repetitive process vent Kaman radiation monitor problems continued to occur throughout 1993. The licensee's trending programs have identified this as a recurring problem. Corrective actions have been implemented and plans to implement additional corrective action were ongoing (paragraph 4.a).

Engineering functional area:

Station Nuclear Safety Operating Committee review of a safety evaluation identified an area that required additional engineering analysis. This analysis resulted in a procedural change for injecting temporary leak sealant into the packing of the Unit 2 loop fill control valve (paragraph 4.b).

An unresolved item was identified associated with the fire barrier adequacy (i.e., MER-5 chiller cable protection), pending demonstration by the licensee that the installation and design meets commitments to and regulatory requirements of 10 CFR, Part 50, Appendix R (paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

* W. Benthall, Supervisor, Licensing
* R. Bilyeu, Licensing Engineer
  H. Blake, Jr., Superintendent of Nuclear Site Services
* R. Blount, Superintendent of Maintenance
* D. Christian, Assistant Station Manager
  J. Costello, Station Coordinator, Emergency Preparedness
* J. Downs, Superintendent of Outage and Planning
  D. Erickson, Superintendent of Radiation Protection
  A. Friedman, Superintendent of Nuclear Training
* B. Hayes, Supervisor, Quality Assurance
* M. Kansler, Station Manager
  C. Luffman, Superintendent, Security
  J. McCarthy, Superintendent of Operations
* A. Price, Assistant Station Manager
  R. Saunders, Assistant Vice President, Nuclear Operations
  E. Smith, Site Quality Assurance Manager
* T. Sowers, Superintendent of Engineering
  J. Swientoniewski, Supervisor, Station Nuclear Safety
* G. Woodzell, Nuclear Training

NRC Personnel

* M. Branch, Senior Resident Inspector
* S. Tingen, Resident Inspector
* J. York, Resident Inspector

*Attended Exit Interview

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

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

2. Plant Status

Unit 1 began the reporting period at 80% power on day 31 of the power coastdown for refueling. On December 21, power was reduced from 72% to approximately 62% in order to remove one tandem drive motor from one of the two main feedwater pumps for use on Unit 2. The unit operated at 62% power for the remaining period, limited by only one MFWP. The refueling outage is still scheduled to commence on January 21, 1994.

Unit 2 began the reporting period at 100% power. On December 22, power was reduced to approximately 60% in order to replace a main feedwater pump motor that was experiencing vibration problems. After the Unit 1 motor was installed in Unit 2, the unit was returned to 100% power on December 25.

3. Operational Safety Verification (71707, 42700)

The inspectors conducted frequent tours of 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 TSs and to maintain overall facility operational awareness. Instrumentation and ECCS lineups were periodically reviewed from control room indication to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. Deviation reports were reviewed to assure that potential safety concerns were properly addressed and reported.

a. Unit 2 Control Rod Drive System Urgent Failure Alarm and NOED

On December 15, at 8:37 a.m., a rod control system urgent failure occurred on Unit 2 during scheduled control rod exercising. The urgent failure rendered group 1 rods powered from cabinet (2-RC-CAB-1AC) immovable (TS inoperable). The rods affected included group 1 rods in SDB "A" as well as CB "A" and "C". In SDB "A", the first bank tested, the four group 2 rods had inserted three steps into the core while the four group 1 rods that were also selected remained fully withdrawn. At 8:37 a.m., a LCO was entered in accordance with TS 3.12.C.3. TS 3.12.C.3 required that inoperable control rod assemblies be restored to operable status within two hours or that the plant be put into a hot shutdown condition within the next six hours.

Initial troubleshooting began immediately and was witnessed by the inspectors. This troubleshooting involved looking for lit indicator lamps or blown fuses as well as taking electrical reading at test points inside the rod control cabinet. There were no lit indicator lights or indication of blown fuses and the electrical readings appeared normal. The K-2 failure detector card appeared loose (i.e., about 1/8-inch from fully seated). This card was removed, reinstalled, and additional electrical measurements made with no change in readings noted. The K-2 card was replaced and again there was no noted change in electrical readings. The old card was reinstalled. However, when the I-2 card, removed to ensure the gripper coils would stay de-energized during troubleshooting, was reinserted, I&C personnel noted that lights on the J-1 failure detector card began flashing. The J-1 card was replaced and the urgent failure reset. After realigning the SDB "A" rods to fully withdrawn per a temporary change to the

rod realignment procedure, the operators attempted to again perform the rod exercise PT. The rod urgent failure reoccurred. After determining that further troubleshooting and repairs could not be completed within the action time of the TS, the licensee requested enforcement discretion.

The NRC verbally granted enforcement discretion from TS 3.12.C.3 for Unit 2 only during a telephone conference on December 15, 1993. Written enforcement discretion was issued the next day. The discretion permitted continued operation of Unit 2 at power for a period of 24 hours versus the two hours specified in TS 3.12.C.3. The additional time was projected to allow troubleshooting and repairs to the Control Rod Drive System. Although the control rod assemblies were immovable on demand from the Control Rod Drive System, the ability of the control rod assemblies to perform their intended safety function (trip into the core) when a safety system setting was reached was not affected.

Additional troubleshooting after the second urgent failure revealed that the removed J-1 failure detection card had two loose capacitors that were not correctly soldered. This defective J-1 card had masked the problem that caused the first urgent failure. The second urgent failure resulted in the J-1 card indicating that the failure occurred in the phase "C" stationary gripper circuitry. Both the phase control and firing cards for this circuit were replaced and the control rods were realigned and satisfactorily tested in accordance with periodic test 2-PT-6, Control Rod Assembly Partial Movement. The Control Rod Drive System was returned to service and the LCO terminated at 3:06 p.m. on the December 15. This NOED is considered closed.

The inspectors noted that these rod equipment failures were further examples of continuing equipment malfunctions associated with the Control Rod Drive System. The inspectors discussed their concerns with the Station Manager who indicated that a Station Level 1 priority had been opened for engineering to review past failures and make recommendations for improvements. The licensee's current schedule for this project indicates that the review should be completed in time to allow for the implementing improvements during the upcoming (January 1994) Unit 1 RFO. Unit 2 improvements should be factored into the next RFO, scheduled for September 1994.

b. Cold Weather Protection (71714)

During a plant tour on December 12, the inspectors noted that the licensee was performing operations check list procedure no. OC-21, Severe Weather OC, dated September 7, 1993. This procedure covers the following forecast weather conditions: high winds and/or heavy rains, extreme cold and/or heavy snow, and severe hot weather.

High winds and freezing weather had been forecast for this period of time. High winds and below freezing temperatures were expected in the area and operations, maintenance, etc., used this procedure to ensure that proper preparations have been made for the expected inclement weather.

In addition, the inspectors discussed the normal freeze protection program with the licensee. This program was implemented by monthly performance (October through March) of STP-52, Cold Weather Protection, dated April 3, 1992. This procedure contained a detailed checklist of areas and components that need to be routinely inspected to ensure that there was adequate protection to prevent freezing. This procedure, STP-52, was performed by both operations and maintenance personnel. Deficiencies that were noted while performing STP-52 were documented and discrepancy reports/work requests were written to schedule corrective action. On December 20, the inspectors reviewed the latest deficiency list and noted that they were either complete, being worked, or scheduled. Walkdowns of exposed areas susceptible to freezing was conducted by the inspectors. No discrepancies were identified that would indicate that the program was not being adequately implemented.

Within the areas inspected, no violations were identified.

4. Maintenance Inspections (62703, 42700)

During the reporting period, the inspectors reviewed the following maintenance activities to assure compliance with the appropriate procedures.

a. Process Vent Radiation Monitor

During this inspection period the inspectors reviewed the reliability of the Kaman process vent high range effluent monitors. Previous IRs have addressed recurring problems with the Kaman radiation monitors. Most recently, IR 93-23 addressed spiking on the Kaman ventilation vent effluent monitor 1-VG-RI-1 (TS Table 3.7.6 Item 12).

TS Table 3.7.6, specified operability requirements for accident monitoring instrumentation. Item 11 of this table specified operability requirements for the process vent high range effluent radiation monitors. Kaman radiation monitors 1-GW-RM-130-1/2 fulfill this requirement. Whenever these radiation monitors are declared inoperable, an alternate method for monitoring the process vent effluent was implemented in accordance with TSs.

The process vent Kaman radiation monitors have a history of operational problems. In 1991, approximately 11 DRs were written due to operational problems. Ten DRs were written in 1992.

Twenty DRs were written in 1993. Recurring problems associated with these radiation monitors involved defaulting setpoints, the iodine/particulate sample becoming saturated with water, check source failures, and miscellaneous other problems. The licensee's trending programs have identified this as a recurring problem. Corrective actions have been implemented and plans to implement additional corrective action are ongoing. The inspectors will continue to monitor the performance of the process vent Kaman radiation monitors in order to evaluate the corrective action's effectiveness.

b. Valve Packing Repair with Temporary Leak Sealant

TS 4.11.A.4 and 3.3.A.12 specify that total system uncollected leakage from SI system valves, flanges, and pumps located outside of containment not exceed 3836 cc/hr. The SI system leakage is monitored by performing periodic testing and walkdowns. System leakage measurements are recorded and tracked in accordance with procedure 2-NPT-ZZ-001, Quantifying of System External Leakage.

While performing a system leakage inspection on December 23, operators identified a significant leak rate coolant increase from the packing of the Unit 2 loop fill control valve, 2-CH-FCV-2160. The packing leak rate which was previously identified as 6 cc/hr had increased to 1800 cc/hr. On December 27, the coolant leak rate from the packing increased to 3120 cc/hr. Leakage from the remaining components in the SI system was very low and therefore the system's total leakage rate remained below the TS maximum value of 3836 cc/hr.

On December 31, the loop fill control valve packing leak was stopped by injecting a temporary leak sealant into the packing area. This maintenance was accomplished by WO 260090-3 and procedure 0-MCM-1918-01, On Line Repairs. The inspectors reviewed the procedure and verified that there were provisions for limiting the amount of leak sealant injected into the packing area and restricting the leak sealant injection pressure. The inspectors also reviewed the work history dating back to 1991 for the Unit 2 loop fill control valve and verified that the valve had not previously been injected with a temporary leak sealant. The valve was repacked during the previous Unit 2 1993 RFO. The inspectors also verified that there was a WR initiated to return the valve to it's original condition.

The loop fill control valve is a containment isolation valve that is normally closed and not repositioned while the plant is operating. Injecting temporary leak sealant into the packing area precluded further valve operation. SE 93-246, dated December 30, was prepared to evaluate operating the unit with the loop fill control valve permanently shut. The SE concluded that it was acceptable to operate the unit in this condition until the next

RFO. The inspectors reviewed SE 93-246 and attended the initial SNSOC meetings that reviewed the SE. The inspectors noted that the SE was not initially approved by SNSOC. SNSOC had questioned if the design pressure rating of the packing leak off piping was evaluated when determining the maximum temporary leak sealant injection pressure. The packing leak off piping was the injection point for the temporary leak sealant and the design pressure of this piping was not originally evaluated. As a result of SNSOC questioning, the maximum temporary leak sealant injection pressure was reevaluated and lowered. The SE was subsequently approved by SNSOC. The inspectors concluded that the initial engineering review for the temporary leak repair was incomplete. However, the SNSOC review and approval added value to the leak repair process, resulting in an acceptable temporary repair.

Within the areas inspected, no violations were identified.

5. BOP Inspection (71500)

The inspectors conducted tours of selected TB and other plant areas susceptible to flooding. During these tours, the inspectors verified the availability of the non-safety related TB sump pumps which the licensee relies upon to mitigate certain flooding scenarios. Additionally, the inspectors were sensitive to any work activities that would increase the possibility of TB flooding such as openings in the condenser waterboxes or piping systems.

On December 29, the inspectors witnessed the licensee performing maintenance associated with replacing TB sump pump 1-PL-P-2F discharge isolation valve 1-PL-12. This maintenance was accomplished in accordance with WO 279713-04. In order to accomplish this maintenance, the power supplies to three of the nine TB sump pumps were danger tagged in the off position. The three TB sump pumps were inoperable for approximately 2.5 hours while the maintenance was performed.

Previous licensee commitments to the NRC stated that at least seven of the nine TB sump pumps would be operable. The licensee reevaluated the IPE calculations and concluded that for short periods of time it was acceptable to have at least six TB sump pumps operable. Installing improved SW expansion joint spray shields was one of the contributors in reducing the critical flood flow rate which allowed operating with six TB sump pumps. The licensee was drafting a letter to the NRC revising their commitment.

The inspectors concluded that 1-PL-12 replacement was accomplished in accordance with the licensee's procedures for minimizing the impact of flooding in the TB.

Within the areas inspected, no violations were identified.

6. Review of Plant Modifications (37828)

The inspectors have been closely monitoring the plant modification to improve the reliability of the control room and emergency switchgear room chillers. This project is commonly referred to as the MER-5 modification. The modification basically consisted of constructing a seismic structure to contain two additional chiller units with their support systems. Additionally, the modification added flexibility to the power supplies for the two new and the three existing chiller units.

On December 28, the inspectors witnessed/reviewed two activities associated with the MER-5 modification. The first involved a freeze seal to allow valve replacement and tying chill water to one of the three existing chillers. The second involved installing 3-M fire wrap over cables and conduit in order to establish fire separation between the two electrical trains that power the chiller units.

The freeze seal was installed using WO 262059-08 and was controlled by procedure 0-MCM-1918-03 revision 0, Freeze Seal of Piping. The procedure required that a SE be performed and approved by SNSOC. The inspectors reviewed the SE (93-239A) and found it acceptable. The piping being frozen was 3-inch diameter carbon steel piping. The inspectors noted that the piping surface in the freeze seal vicinity was very rusty and would be difficult to perform the NDE required prior to freeze seal installation. The Site Services personnel working the job showed the inspectors IPR 93-431 that documented the surface condition and provided the engineering disposition of the concern prior to the freeze seal installation. Specifically, surface grinding to smooth the area being frozen was performed followed by a successful NDE of the area.

The conduit fire wrap was being installed per DCP 90-07. The fire barrier being installed on the conduit that housed "H" bus power supply cables was necessary since the "H" bus conduit was routed through the "J" bus switchgear room within approximately 1-2 feet of the switchgear. 10 CFR 50, Appendix R requires that train (bus) separation be established by physical distance (20 feet), or by 3-or 1-hour fire barriers depending on the specific circumstances. The stated purpose of the modification was to provide a 1-hour fire barrier between the two electrical power trains.

The inspectors reviewed the work package at the job site and noted that the 3-M installation/qualification instructions discussed a configuration that was different from that being installed. The 3-M qualification for a 1-hour fire rating described a three wrap system for < 5 inch aluminum conduit, consisting of two wraps of E-53 and one wrap of E-54. The system being installed consisted of three wraps of E-54 which was described by the licensee and their contractor as thicker material than the E-53 wrap. The inspectors requested verification that the actual installation configuration of 3 wraps of 3-M E-54 was bounded by test reports from the vendor.

The inspectors were provided a copy of a memorandum from the corporate fire protection engineer to Site Engineering. This memorandum contained the engineering evaluation for qualifying three wraps of E-54 material. The basis for the fire wrap qualification configuration being installed was stated to be several 3-M test reports. However, fire test report no. 3MFT87-11, which was described as the closest to the actual installation, in a memorandum from PROMATEC, the licensee's contractor, was not referenced. The inspectors requested a copy of fire test report no. 3MFT87-11 for review.

The above referenced memorandum also contained engineering evaluation no. 25 titled, "Evaluation of Lack of an Automatic Fire Suppression System in Unit 2 Emergency Switchgear Room Surry Power Station". The evaluation's purpose was to allow using 1-hour fire barrier (i.e., 3 layer fire wrap on power supply cables for the chiller units). The original design had specified a 3-hour fire barrier (i.e., 5 wraps of 3-M material) for the cables in question but, because of space considerations, only 3 wraps could be installed. The evaluation referenced 10 CFR 50, Appendix R, section III.G.2.c requirement that stated that two trains of safe shutdown cables could be separated by a 1-hour rated fire barrier, with fire detection and an automatic fire suppression system installed in the area. The licensee's evaluation was addressing the fact that the emergency switchgear room, where the cables in question were located, was equipped with a <u>manual</u> not <u>automatic</u> fire suppression Halon system. 10 CFR 50, Appendix R, section III.G.2.c would require a 3-hour barrier for this area and an exemption would be necessary.

During subsequent discussions, the licensee produced a Surry Appendix R Report that states that the emergency switchgear rooms for Units 1 and 2 (fire zones 3 and 4) only had to meet the requirements of 10 CFR 50, Appendix R, section III.G.3 in lieu of III.G.2.c since remote shutdown capability existed. Section III.G.3 only required a fixed suppression system and did not require it to be automatic. Additionally, train separation was not specified. Based on the conflicting data, it was unclear as to the fire protection and cable protection design requirements for this area. The fire protection design engineer stated that for new installations, III.G.2.c requirements were desired. Since the control room and emergency switchgear room chiller system were common to both units, the inspectors questioned the licensee as to whether the system would be needed to cool equipment that was relied upon for remote/alternate shutdown. Thereby, it would be required to meet the requirements of III.G.2.c (i.e., protected by a 3-hour barrier or 1-hour barrier with automatic fire detection and suppression).

The inspectors requested additional information and historical correspondence as to the design requirements for protecting the cable in question. This item is identified as URI 50-280, 281/93-30-01, MER-5 Power Supply Cables Fire Barrier Adequacy, pending demonstration by the licensee that the installation and design meets commitments to and regulatory requirements of 10 CFR 50, Appendix R. Additionally, 3-M

fire test report 3MFT87-11 has not been provided by the licensee or reviewed by inspectors. The licensee has elected to maintain a fire watch in the area until this issue is resolved.

Within the areas inspected, no violations were identified.

7. Action on Previous Inspection Items (92701, 92702)

a. Closed VIO 50-280, 281/92-07-03, Failure To Prevent Foreign Material From Entering SW System. When flow testing the Unit 1 RSHXs during the 1992 Spring RFO, it was identified that the flow rate through RSHX 1-RS-E-1B was low. Inspection of the heat exchanger revealed that a rain jacket and rain pants were present in the tubesheet area which restricted the flow of SW. It was concluded that the rain gear was inadvertently left in the system during maintenance that was performed during the previous fall 1990 RFO. In a letter dated May 29, 1992, the licensee responded to this violation. The cause of this event was attributed to inadequate implementation of FME controls during the maintenance performed on the RSHX system during the 1990 RFO. As corrective action VPAP-1302, Foreign Material Exclusion Program, was implemented after the Fall, 1990, Unit 1 RFO to establish station wide FME controls. In addition, VPAP-1302 was revised following rain gear identification to further enhance the FME program by requiring additional requirements for documenting closeout inspection results. The inspectors reviewed VPAP-1302, revision 3, and verified that the corrective actions in response to violation were implemented.

b. Closed VIO 50-280, 281/92-13-01, Failure to Perform Safety Evaluations for Procedures That Were Used to Operate Plant Systems Differently Than Described in the UFSAR. This issue involved three examples in which the licensee operated plant systems in a different manner than described in the UFSAR but had not first prepared written safety evaluations pursuant to 10 CFR 50.59. The licensee responded to this violation in a letter dated July 31, 1992. As corrective action, safety evaluations were prepared for each of the examples identified. The inspectors reviewed SEs 92-126, dated June 4, 1992, 92-127, dated June 4, 1992 and 92-171, dated July 22, 1992. SEs 92-171 and 92-127 identified that additional procedural controls were necessary. The inspectors reviewed procedures 2-OP-49.7, Filling and Draining RSHX Service Water Supply Piping, revision 2 and 0-OPT-FP-005, Fire Protection Water Pumps, revision 1 and verified that the additional procedural controls were properly incorporated.

Within the areas inspected, no violations were identified.

8. Exit Interview

The inspection scope and findings were summarized on January 4, 1994, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed in the front of the report and those listed below.

Item Number	Status	Description (Paragraph No.)
URI 50-280, 281/93-30-01	Open	MER-5 Power Supply Cable Fire Barrier Adequacy (paragraph 6).
VIO 50-280, 281/92-07-03	Closed	Failure To Prevent Foreign Material From Entering SW System (paragraph 7.a).
VIO 50-280, 281/92-13-01	Closed	Failure to Perform Safety Evaluations for Procedures That Were Used to Operate Plant Systems Differently Than Described in the UFSAR (paragraph 7.b).

Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

9. Index of Acronyms and Initialisms

BOP - BALANCE OF PLANT
CB - CONTROL BANK
CC/HR - CUBIC CENTIMETERS PER HOUR
DCP - DESIGN CHANGE PACKAGE
DR - DEFICIENCY REPORT
ECCS - EMERGENCY CORE COOLING SYSTEM
FME - FOREIGN MATERIAL EXCLUSION
I&C - INSTRUMENTATION AND CALIBRATION
IPE - INDIVIDUAL PLANT EXAMINATION
IPR - INSTALLATION PROBLEM REPORT
IR - INSPECTION REPORT
LCO - LIMITING CONDITIONS OF OPERATION
MER - MECHANICAL EQUIPMENT ROOM
MFWP - MAIN FEED WATER PUMP
NDE - NONDESTRUCTIVE EXAMINATION
NOED - NOTICE OF ENFORCEMENT DISCRETION
NRC - NUCLEAR REGULATORY COMMISSION
OC - OPERATIONS CHECKLIST
PT - PERIODIC TEST
RFO - REFUELING OUTAGE
RS - RECIRCULATION SPRAY

RSHX	-	RECIRCULATION SPRAY HEAT EXCHANGER
SDB	-	SHUT DOWN BANK
SE	-	SAFETY EVALUATION
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SW	-	SERVICE WATER
TB	-	TURBINE BUILDING
TS	-	TECHNICAL SPECIFICATION
UFSAR	-	UPDATED FINAL SAFETY ANALYSIS REPORT
URI	-	UNRESOLVED ITEM
VIO	-	VIOLATION
WO	-	WORK ORDER
WR	-	WORK REQUEST