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

Report Nos.: 50-280/94-11 and 50-281/94-11

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: April 3 through May 7, 1994

Inspectors: LW Garner for — 5-25-94
M. W. Branch, Senior Resident Inspector — Date Signed

LW Garner for — 5-25-94
S. G. Tingen, Resident Inspector — Date Signed

Accompanying Personnel: D. M. Tamai
L. W. Garner

Approved by: G. A. Belisle for — 5/25/94
G. A. Belisle, Section Chief
Division of Reactor Projects — Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance and surveillance inspections, and on-site engineering review.

Results:

Operations functional area

The continued use of the not applicable provisions in procedure STP-33.6, Instrument Air Blowdown, revision 2, resulted in not correcting deficiencies in the procedure (paragraph 3.b).

<u>Maintenance functional area</u>

The post maintenance tests performed after replacing several Unit 1 consequence limiting safeguards relays did not fully verify, by testing, that proper circuit continuity existed. Relay bench testing and second party verification of field wiring terminations provided an adequate confidence level that the relays were properly installed (paragraph 4.b).

<u>Engineering functional area</u>

The failure to revise the Unit 1 steam flow calorimetric computer program to incorporate changes implemented by Engineering Calculation EE-0418 prior to unit restart following the refueling outage was identified as Violation 50-280/94-11-01 (paragraph 3.a).

A weakness in the operational readiness review process was identified. A non-safety related procedure was not recognized as needing revision after the hardware was changed/removed by plant modifications. Additionally, a system engineering review of completed surveillance test procedures did not identify the need to change the procedure (paragraph 3.b).

REPORT DETAILS

1. Persons Contacted

<u>Licensee Employees</u>

*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
*D. Hayes, Supervisor of Administrative Services
*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

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

<u>NRC Personnel</u>

*A. Belisle, Section Chief
*M. Branch, Senior Resident Inspector
*D. Tamai, NRC Intern
*S. Tingen, Resident Inspector

*Attended Exit Interview

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

2. Plant Status

Units 1 and 2 operated at power for the entire inspection period. Unit 2 operated at reduced power due to steam generator level oscillations.

3. Operational Safety Verification (71707)

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. Operation of Unit 1 Above Licensed Maximum Power

On March 31, DR S-94-0804 was written to document a condition where Unit 1 operated for a period of 7 hours and 12 minutes above the licensed maximum power level of 2441 MWT. Specifically, at 2:18 p.m. on March 30, reactor power based on the power range NIs and the CALCALC computer program, was increased from 98% to 100%. The unit had just completed a RFO and this was the first time the unit had operated at full power following the RFO. At 100% reactor power, operators noted that the turbine generator electrical output of 830 to 835 MWE was higher than normal and also exceeded the design value of 828 MWE. The unit operated at this power level until 8:54 p.m., of the same day, when management ordered power to be reduced in order to investigate the discrepancies between indicated NI reactor power and turbine output. At 9:30 p.m. on March 30, reactor power was stabilized at 98.3%. The licensee later confirmed that Unit 1 had operated for one shift at an average power level of 2453 MWT which exceeded the maximum licensed power level of 2441 MWT. On March 31 a reactor power calorimetric was performed utilizing feed flow. The power range NIs were adjusted based on the results of this calorimetric and the unit was then returned to full power operation. On that same day the steam flow calorimetric computer program was revised.

Through subsequent reviews, the licensee concluded that the power range NIs were not indicating the correct power level at full power. The NIs were indicating approximately 1% lower than the actual power level. During the 1994 Unit 1 RFO, the main steam flow transmitters were respanned and the main steam flow instruments were rescaled. The steam flow calorimetric computer program was not revised to incorporate these new parameters. As a result the power range NIs did not indicate the correct power level because at approximately 85% reactor power they were adjusted to match reactor power that was calculated based on the inaccurate steam flow calorimetric computer program. TS Table 4.1-1 requires NI power be verified daily against a heat balance standard (calorimetric calibration). The licensee's method for performing the TS required heat balance surveillance used the CALCALC computer program and was contained in procedure 1-OPT-RX-001, Reactor Power Calorimetric Using CALCALC Computer Program, revision 1.

The licensee performed RCE 94-11, Surry Unit 1 Operation Above 100% Power, in order to investigate this event. The inspectors also reviewed the circumstances surrounding this event. RCE 94-11 concluded that root cause of this event was that the process for implementing changes to instrumentation based on revised Engineering Calculation EE-0418, Determination of Feedwater Flow and Steam Flow Transmitter's Calibration Spans from CHEMTRAC and Flowcalc Data Resulting from Special Test 1-ST-300, revision 1, was not adequately coordinated. In this case the process did not ensure that the steam flow calorimetric computer program was revised prior to unit restart following the RFO. The inspectors reviewed RCE 94-11 and considered it to be comprehensive and thorough. The RCE also identified other examples where the lack of a formal process for controlling and implementing calculation changes resulted in problems at Surry and North Anna power stations. The RCE and corrective actions to formalize the process were approved by SNSOC on April 28.

During this event the power range NI high flux, Overpower Delta T, and Overtemperature Delta T protective settings were in error by approximately 1% in the nonconservative direction. The inspectors reviewed the licensee's policy for reactor trip protective settings which required that 2% margins be established between actual settings and TS limiting settings. The inspectors concluded that the TS limiting settings were not exceeded during this event.

During the 1992 Unit 1 RFO, feedwater flow measurements were obtained by using a chemical trace via procedure CHEMTRAC, revision 1. These precision feedwater flow measurements were analyzed by electrical engineering via Engineering Calculation EE-0418 and were used to revise steam and feedwater flow instrument scaling values during that outage. During the recent 1994 Unit 1 RFO, main steam flow scaling values were further refined in accordance with revision 1 to EE-0418. The refined main steam flow scaling values were implemented but the steam flow calorimetric computer program was not revised.

UFSAR Chapter 14, Safety Analysis, describes the initial condition at the onset of the accidents and transients analyzed. Many accident analyses assume a steady state power level of 102% since that is the claimed accuracy of the calorimetric. The calorimetric is the standard used to calibrate NI instruments and thereby establish the setpoints of the safety actions that are initiated from these instruments. Some accident analysis state that a power level of 102% of 2441 MWT (current license limit) was assumed while others assumed 102% of 2546 MWT (engineering safety feature rating). The licensee indicated that all accident analyses had been re-performed using the 2546 MWT rating although this rating was not recognized in the current UFSAR revision.

The steam flow values used in the Unit 2 calorimetric were reviewed and the inspectors verified that a similar condition did not exist. Specifically, during the Unit 2 1991 RFO, the feedwater flow venturis were replaced and a special test was performed to verify calibration curves for the new venturis. Main steam flow scaling deficiencies were identified and corrected as a result of this modification and this issue was discussed in NRC Inspection Report Nos. 50-280, 281/91-21. The Unit 2 steam and feed flow calorimetric computer programs were properly revised.

10 CFR 50, Appendix B Criterion III, Design Control, as implemented by section 17.2.3 of the Operational QA Program Topical Report, VEP-1-5A (Updated), requires that measures be established to assure that design requirements be correctly translated into specifications, drawings, procedures, and instructions. Electrical Engineering Implementing Procedure EE-029, Calculation Controlling Procedure, revision 2, stated scope (2.2) requires that calculation results be effectively communicated to the applicable power station. The failure to revise the Unit 1 steam flow calorimetric computer program to incorporate the changes implemented by Engineering Calculation EE-0418, revision 1, prior to restarting the unit following the RFO was identified as Violation 50-280/94-11-01, Failure To Revise The Steam Flow Calorimetric Computer Program.

b. ESF Walkdown

The inspectors walked down portions of the Unit 1 and Unit 2 compressed air system. The primary purpose of the system is to provide pressurized air to pneumatically operated valves. The walkdown included the service, instrument, and containment air compressors, instrument and service air receivers, and instrument air dryers and filters. Major system valves were verified to be positioned in accordance with procedure OP-46.1A, Instrument and Service Air Compressors No.2 Turbine Building/Outside Valves Alignment, revision 8, and system drawings. During the walkdown, the inspectors verified that valves were properly aligned and locked as required, air lines were adequately supported, no deficient physical conditions were present, housekeeping was acceptable, and breaker positions were proper on equipment not in operation. Ten incidents of incorrect or missing tags were identified by the inspectors and provided to the licensee for correction.

The system engineer was interviewed on system operability, recent modifications and outstanding maintenance items. The inspectors also walked down part of the system with the system engineer. The service air compressor control cabinets were opened and inspected for adequate housekeeping and equipment material condition. The inspectors concluded that the system was being adequately maintained.

Monthly surveillance procedure STP-33.6, Instrument Air Blowdown, revision 2, test results from 12/93 to 4/94 were reviewed. Two examples were identified where the STP was not updated after modifications to the plant were implemented. The first example was DCP-93-040, BS Groundwater Intrusion and Control, revision 6, which removed valve 1-IA-735. The Design Change Process, as outlined in VPAP-0301, revision 3, is intended to identify affected drawings and procedures. Per the design change process an ORR initiates the update of affected priority documents. The ORR for DCP-93-040 did not identify procedure STP-33.6 as an affected procedure. The second example involved DCP-90-08, MER-5 Chiller Installation - CR HVAC Upgrade, revision 38, which changed valve 2-IA-211 from a test connection to a non-testable IA supply valve to MER #5.

STP-33.6 was annotated for three consecutive months with N/A instead of correcting the procedure, and in some cases alternate test valves were utilized. The procedure allowed omission of any valves at the discretion of the shift supervisor provided that an explanation was given. A liberal use of these instructions allowed Operations personnel to N/A valves that were not testable and continue the surveillance without a procedure change. Furthermore, the system engineer reviewed each completed procedure through a post-surveillance critique and did not initiate a procedure change.

The inspectors identified a weakness in the ORR process, in that, non-safety related procedure STP-33.6 was not recognized as needing revision after the hardware was changed/removed by plant modifications. Additionally, Operations personnel's continued use of the STP-33.6 N/A provision resulted in not correcting procedural deficiencies and a system engineering review likewise failed to identify the need to change the procedure.

Within the areas inspected, one violation was identified.

4. Maintenance And Surveillance Inspections (62703, 61726)

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

a. Unit 1 A Reactor Trip Breaker

On April 12, while performing monthly 1-PT-8.1, Reactor Protection System Logic (for normal operation), revision 6, the Unit 1 A RTB failed to remain closed. The breaker had successfully closed twice earlier in the procedure. The A RTB was removed for repair and replaced with the B RTBB. Both the licensee and the vendor, Westinghouse, determined that the C phase of the control relay contact had insufficient contact tension. Additionally, the vendor recommended that breaker closure timing be changed to deenergize the closing coil slightly after the breaker mechanically latches. The inspectors observed the reinstallation of the A RTB. The B RTBB was removed from the A RTB position and returned to its original position and the A RTB was reinstalled. The work was done in accordance with procedures and adequate coordination with the control room was noted. The breaker was successfully tested in accordance with 1-PT-8.1.

The failure of the A RTB to remain closed also occurred on March 24, 1994, during the monthly test, 1-PT-8.2, Reactor Protection System Logic (for shutdown), revision 4. The cause was diagnosed as a faulted latch pawl spring. After replacing the spring, the breaker was tested satisfactorily and returned to service.

b. Unit 1 CLS Relay Replacement

In 1993, the licensee performed a Level 1 engineering study that identified six Hi CLS relays in each unit that would result in a reactor trip if a single relay failure occurred. Prior to performing this Level 1, several reactor trips occurred due to single relay failures. During the Unit 1 spring 1994 RFO, these six CLS relays were replaced. In addition several other Hi CLS relays and Hi-Hi CLS relays were replaced because the relays were either chattering or had a crack in the coil case. The inspectors reviewed the maintenance, PMTs, and surveillances associated with replacing relays 3/4-CLS-1A (WO 269580 01), 3/4-CLS-1B (WO 269582 01), 3-CLS-1AM (WO 269581 01), 3-CLS-1BM (WO 269583 01), CR-CLS-1A1 (WO 269380 01), CR-CLS-1B1 (WO 269589 01), CR-CLS-1B13 (WO 283983 01), CR-CLS-2B4 (WO 281784 01), and CR-CLS-2BM-X (WO 267272 01).

The relays were replaced in accordance with procedure 0-ECM-1801-01, Westinghouse Type BFD Relay Replacement, revision 5, and in most cases old style BFD relays were replaced with later model NBFD65NR relays. Prior to installation, each relay was bench tested which included coil testing and verification that the contacts opened and closed as required. Since the new relays had a different contact configuration, the system engineer specified the wiring configuration for each relay 0-ECM-1801-01 attachment 2. The electricians who installed and rewired the relays independently verified that the leads were installed to the relay terminals as specified.

The PMT sheets for replacing Hi-Hi CLS relays CR-CLS-2B4 and CR-CLS-2BM-X required that the relays be tested in accordance with 1-PT-8.5, Consequence Limiting Safeguards Logic (HI-HI Train), revision 2. The inspectors reviewed 1-PT-8.5 performed on

March 21, 1994, and concluded that the relays had been properly tested.

The PMT sheets for replacing Hi CLS relays 3/4-CLS-1A, 3/4-CLS-1B, 3-CLS-1AM, 3-CLS-1BM, CR-CLS-1A1, CR-CLS-1B1 and CR-CLS-1B13 required that the relays be tested in accordance with 1-PT-8.4, Consequence Limiting Safeguards (Hi-Train), revision 2. The inspectors reviewed 1-PT-8.4 performed on March 20 and 21, 1994, and identified the following examples where operation of specific relay contacts were not verified while performing this test:

RELAY	TRAIN	CONTACTS	FUNCTION
3-CLS-1AM	A	18,22 19,23	Actuate Hi CLS
3-CLS-1BM	B	18,22 19,23	Actuate Hi CLS
CR-CLS-1A1	A	1,5	Actuate SI-CLS
CR-CLS-1B1	B	1,5	Actuate SI-CLS

On May 11 the licensee discussed with the NRC the installation and testing performed on the above relays. After consultation with Region II management and cognizant NRR personnel, the inspectors concluded that the bench testing performed on these relays prior to installation combined with the testing performed after installation provided an adequate level of confidence that these relays were properly installed. The inspectors also concluded that the CLS relays were installed and tested in accordance with the licensee's PMT program. No discrepancies were identified.

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

5. On-Site Engineering Review (37551)

Seismic Qualification of the Turbine Building

During an UFSAR review, the inspectors observed in Table 15.2-1 a note concerning the turbine building that stated, "By design, building collapse will not damage any Class I structures and components during earthquake, or tornado-resistant structures and components during tornado." The inspectors inquired if this statement meant that the turbine building was seismically designed. Per UFSAR section 9.10.4.18, safety related equipment located within the turbine building includes control room and switchgear area emergency ventilating units, component cooling water heat exchangers, instrument air compressors, service water valves, and charging pump cooling water and service water system valves along with related cables/cable trays. No areas of the UFSAR reviewed by the inspectors referenced the turbine building as being seismically qualified.

On March 31, 1994, the inspectors met with the licensee's Supervisor of Station Civil Engineering, Supervisor of Corporate Civil Engineering, and the Supervisor of Corporate Engineering Mechanics to discuss this apparent conflict in the design basis. During this discussion, the following information documented in Calculation 11448 was presented:

- The turbine building was designed for normal wind loading (150 mph) considering full sail area of the siding. The major turbine building structural elements were designed for tornado wind loading. The controlling turbine building loading was found to be the tornado wind pressure applied to the major structural elements.

- A comparison of loads generated by tornado wind pressure and seismic motion revealed that the tornado loads would be several orders of magnitude higher. The licensee concluded from this calculation that no specific analysis to seismically qualify the turbine building was necessary. Discussion of the calculation revealed that while the turbine building side panels may be blown away during a tornado the building structural steel should remain intact.

The inspectors reviewed pages 105-110 of Calculation 11448 which was performed by Stone & Webster in July 1967. This calculation concluded that the turbine building structural loads associated with an earthquake were less than the loads associated with a tornado (the limiting design for the turbine building).

The inspectors further discussed the seismic adequacy of the safety related equipment and the raceway systems inside the turbine building. The following information and conclusions were discussed:

- The licensee used EPRI report NP-7150-D, The Performance of Raceway Systems in Strong-Motion Earthquakes, as a reference when evaluating the seismic adequacy of the raceway system within the turbine building. The measurement of the peak ground accelerations in the seismic events discussed in this report varied from 0.12g to 0.85g.

- Seismic damage was limited to only a few items except for sites in excess of 0.55 peak ground acceleration. Surry's peak ground acceleration is 0.15 and therefore not likely to suffer notable damage from a seismic event.

The inspectors reviewed EPRI Report NP-7150-D which demonstrated the types of damage to electrical raceways and electrical conduit that could be expected during specific seismic events. The licensee plans to use this information in further reviewing the adequacy of raceways.

In December 1980, the NRC initiated USI 46, Seismic Qualification of Equipment in Operating Plants, to address seismic adequacy of mechanical and electrical equipment in older nuclear plants such as Surry. The inspectors discussed the walkdowns that are presently in progress (to be completed by the end of 1995) for the electrical and mechanical equipment that are required for the safe shutdown of the plant. These walkdowns should verify the seismic adequacy of this equipment and raceways. Another objective of this program is to verify the interaction of non-safety related (and non-seismic) equipment and safety related equipment. The industry's efforts (SQUG) are for resolving USI A-46 and IPEEE (seismic) issues.

Qualification of Personnel

The inspectors reviewed the qualifications of the three individuals described above who were involved in resolving the seismic issues at Surry. All of the individuals met the supervisory qualifications required by ANS 3.1 and SQUG for seismic capability engineer. The requirements are as follows:

- ANS 3.1, Standard for Qualification and Training of Personnel for Nuclear Power Plants, stated that supervisory personnel should have a BS in Engineering and should have six years of professional level managerial experience in the power field. In addition, several of the individuals possessed PE licenses.

- SQUG procedure, Generic Implementation Procedure For Seismic Verification of Nuclear Plant Equipment, had requirements for a seismic capability engineer (Sec. 2.1.2). These requirements were an engineering degree, or equivalent, completion of a SQUG developed training course on seismic adequacy verification of nuclear power plant equipment, and at least five years experience in earthquake engineering applicable to nuclear power plants.

The inspectors had no further concerns in this area.

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

6. Exit Interview

The inspection scope and findings were summarized on May 10, 1994, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results addressed in the Summary section and those listed below.

Item Type/Number	Status	Description/(Paragraph No.)
VIO 50-280/94-11-01	Open	Failure To The Revise Steam Flow Calorimetric Computer Program (paragraph 3.a)

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

7. Index of Acronyms and Initialisms

ANS	AMERICAN NUCLEAR SOCIETY
BS	BACHELOR OF SCIENCE
CFR	CODE OF FEDERAL REGULATIONS
CLS	CONSEQUENCE LIMITING SAFEGUARDS
CR	CONTROL ROOM
DCP	DESIGN CHANGE PACKAGE
DR	DEVIATION REPORT
ECCS	EMERGENCY CORE COOLING SYSTEM
EE	ENGINEERING EVALUATION
EPRI	ELECTRICAL POWER RESEARCH INSTITUTE
ESF	ENGINEERED SAFETY FEATURE
g	GRAVITY
HVAC	HEATING VENTILATION AND AIR CONDITIONING
IPEEE	INDIVIDUAL PLANT EXTERNAL EVENT EXAMINATION
MER	MECHANICAL EQUIPMENT ROOM
MWE	MEGAWATT ELECTRIC
MWT	MEGAWATT THERMAL
N/A	NOT APPLICABLE
NI	NUCLEAR INSTRUMENTATION
NRC	NUCLEAR REGULATORY COMMISSION
ORR	OPERATIONAL READINESS REVIEW
PE	PROFESSIONAL ENGINEER
PMT	PREVENTATIVE MAINTENANCE TEST
PT	PERIODIC TEST
QA	QUALITY ASSURANCE
RCE	ROOT CAUSE EVALUATION
RFO	REFUELING OUTAGE
RTB	REACTOR TRIP BREAKER
RTBB	REACTOR TRIP BYPASS BREAKER
SI	SAFETY INJECTION
SNSOC	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SQUG	SEISMIC QUALIFICATION UTILITY GROUP
STP	SURVEILLANCE TEST PROCEDURE
T	TEMPERATURE
TB	TURBINE BUILDING
TS	TECHNICAL SPECIFICATION
UFSAR	UPDATED FINAL SAFETY ANALYSIS REPORT
USI	UNRESOLVED SAFETY ISSUE
VIO	VIOLATION
WO	WORK ORDER