UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

July 17, 2000

EA 00-070

Virginia Electric and Power Company
ATTN: Mr. David A. Christian
Senior Vice President and
Chief Nuclear Officer
Innsbrook Technical Center - 2SW
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: SURRY NUCLEAR POWER STATION - NRC INTEGRATED INSPECTION REPORT NOS. 50-280/00-03, 50-281/00-03, and 72-002/00-04

Dear Mr. Christian:

On June 17, 2000, the NRC completed an inspection at your Surry Power Station, Units 1 and 2, and the Surry Independent Spent Fuel Storage Installation. The enclosed report presents the results of that inspection which were discussed on June 23, 2000, with Mr. R. Blount and other members of your staff.

The inspection was an examination of activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. Within these areas, the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, four issues of very low safety significance (three Green and one no color) were identified. All of these issues were determined to involve violations of NRC requirements. However, the violations were not cited due to their very low safety significance and because they had been entered into your corrective action program. If you contest these non-cited violations you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Surry Power Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available **electronically** for public inspection in the NRC Public Document

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Sincerely,
/RA by Larry Garner Acting For/

Robert C. Haag, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket Nos.: 50-280, 50-281, 72-002
License Nos.: DPR-32, DPR-37, SNM-2501

Enclosure: NRC Integrated Inspection Reports 50-280/00-03, 50-281/00-03, and 72-002/00-04

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DATE	7/14/2000	7/14/2000	7/14/2000	7/14/2000	7/13/2000	7/6/2000	7/11/2000
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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-280, 50-281, 72-0002
License Nos.:	DPR-32, DPR-37, SNM-2501
Report Nos.:	50-280/00-03, 50-281/00-03, and 72-002/00-04
Licensee:	Virginia Electric and Power Company (VEPCO)
Facilities:	Surry Power Station, Units 1 & 2 Surry Independent Spent Fuel Storage Installation
Location:	5850 Hog Island Road Surry, VA 23883
Dates:	April 2 - June 17, 2000
Inspectors:	R. Musser, Senior Resident Inspector K. Poertner, Resident Inspector G. McCoy, Resident Inspector J. Coley, Reactor Inspector, RII (Section 1R08 and 4OA4.3) D. Jones, Senior Radiation Specialist, RII (Section 2OS2) L. Hayes, Physical Security Specialist, RII (Section 3PP1 and 3PP2) T. Morrissey, Project Engineer, RII (Section 4OA5.3)
Approved by:	R. Haag, Chief, Reactor Projects Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000280-00-03, IR 05000281-00-03, IR 07200002-00-04, on 4/02-06/17/2000; Virginia Electric and Power Co.; Surry Power Station Units 1 & 2 and ISFSI. Refueling and Outage Activities, Surveillance Testing, Access Controls, Other Activities, TI 2515/144.

The inspection was conducted by resident inspectors and a regional physical security specialist, a regional senior radiation specialist, a regional project engineer, and a regional reactor inspector. This inspection identified four issues, three green and one no color, which were non-cited violations. The significance of issues is indicated by their color (green, white, yellow, red) and was determined by the Significance Determination Process.

Cornerstone: Mitigation Systems

- GREEN. The inspectors identified a non-cited violation in which the licensee failed to follow a required procedure which rendered the anticipated transients without scram mitigation system actuation circuit (AMSAC) inoperable while the plant was operating at power. This is a violation of Surry Power Station Technical Specifications, section 6.4.A.2.

  The risk of having the AMSAC inoperable for less than 8 hours was considered to be of very low safety significance because operator recovery actions and procedures were available if needed. (Section 1R20.2)

- NO COLOR. The inspectors identified a non-cited violation in which a modification was implemented to the auxiliary ventilation system that prevented parallel operation of both fans in the minimum safeguards alignment which would result in one or both fans tripping following an actuation signal. The post-modification testing did not verify proper operation with both fans operating simultaneously. This is a violation of 10 CFR 50, Appendix B, Criterion III.

  The issue was of very low safety significance since the operators could have manually aligned the system for operation. The plant design allowed sufficient time to manually actuate the system such that the safety functions would performed. (Section 1R22)

- GREEN. A non-cited violation was identified for the failure to have an adequate procedure in effect to provide alternative shutdown capability (i.e., to achieve and maintain a safe shutdown condition) in the event of a main control room fire. This is a violation of 10 CFR 50, Appendix R, Section III.L.3.

  The issue was of very low safety significance due to the very low fire initiating event frequency associated with the violation condition. (Section 4OA5.3)

Cornerstone: Physical Protection

- GREEN. The inspectors identified a non-cited violation for the failure to comply with the requirements of the Physical Security Plan (PSP). Specifically, the officer providing the last access control function, at the Primary Access Control on March 27, 2000, and at the Secondary Access Portal on April 26, 2000, did not remain isolated within a hardened structure in order to satisfy the requirements of the PSP. Based on the other response and assessment capabilities in place as well as the licensee's previous four-quarter performance in this area, these findings were determined to be of very low risk significance. (Section 3PP2)

Report Details

Unit 1 operated at power until April 16, 2000, when the unit was shutdown for a scheduled refueling outage. The unit was returned to service on May 9, 2000, and operated at power for the remainder of the reporting period.

Unit 2 operated at power the entire reporting period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

For the systems identified below, the inspectors reviewed plant documents to determine correct system lineup, and observed equipment to verify that the system was correctly aligned:

- Unit 1 Auxiliary Feedwater System (1-OP-FW-001A, "Auxiliary Feedwater Alignment," Rev. 1) ;

- Unit 1 "H" Train Emergency Electrical Power (1-OP-EG-001A, "EDG 1 System Alignment," Rev. 2, P4); and,

- Unit 1 and 2 Component Cooling Water System (1 / 2-OP-51.1A, "Component Cooling System Alignment," Rev. 9).

b. Issues and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of the following areas to assess the adequacy of the fire protection program implementation. The inspectors checked for the control of transient combustibles and the condition of the fire detection and fire suppression systems for (using "SPS Appendix R Report," Rev. 17):

- Unit 1 and 2 Control Room;

- Unit 2 Normal Switchgear Room;

- Unit 2 Cable Vault;

- Emergency Switchgear Room during the removal and repair of door 02-BS-DR-21; and,

- Emergency Diesel Generator (EDG) Rooms during maintenance of number 1 EDG.

b. Issues and Findings

There were no findings identified.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

The inspectors evaluated ISI and repair and replacement activities during the April 2000, Unit 1 refueling outage to determine the effectiveness of the licensee's American Society of Mechanical Engineers (ASME) ISI program. Selection of ASME piping subject to examination for Unit 1 was determined by the Westinghouse risk informed method.

The inspectors observed three augmented ultrasonic examinations of the B loop steam generator feedwater piping, reviewed radiographic film for six welds in the feedwater, residual heat removal (RHR), and low head safety injection (LHSI) systems, and reviewed eddy current evaluations in steam generator "C". Eddy current examinations included 22 hot-leg, top-of-tubesheet, rotating-probe, examinations with anomalies, to verify that these anomalies were not cracks. The inspectors also verified that rejectable indications or defects had not been accepted by the licensee for continued service in any of the nondestructive test methods.

Two Code repair packages for repair and replacement of piping in the A loop LHSI system and the RHR system were examined. A Non-Code repair performed on the "D" component cooling heat exchanger service water discharge piping was reviewed to determine whether these activities were performed in accordance with Generic Letter 90-05.

ISI program requirements for Class 2 pressure retaining piping on the supply side of the emergency core cooling system pumps were examined to verify that the new risk informed program implemented examinations for this low risk but high consequence piping.

One ISI self-assessment and one Nuclear Oversight Audit with five associated discrepancy reports were also reviewed to determine if problems associated with ISI were entered into the licensee's corrective action program, and that effective action was being taken. These observations by the inspectors verified that the ISI, and repair, and replacement of Class 1, 2, & 3 pressure retaining components at the Surry facility were performed in accordance with Technical Specifications, the 1989 edition of the ASME Code, Sections XI & V, and correspondence between NRC staff and the licensee.

b. Issues and Findings

There were no findings identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator performance during simulator training session RQ-00.2.ST-2, “AOP Training,” to determine whether the operators:

- were familiar with and could successfully implement the procedures associated with recognizing and recovering from a dropped rod accident;
- recognized the high-risk actions in those procedures; and,
- were familiar with related industry operating experiences.

b. Issues and Findings

There were no findings identified.

1R12 Maintenance Rule Implementation

.1 Equipment Issues

a. Inspection Scope

For the equipment issues described in the plant issues (PIs) and deviation reports (DRs) listed below, the inspectors reviewed the licensee’s implementation of the Maintenance Rule (10 CFR 50.65) using VPAP 0815, “Maintenance Rule Program,” Rev. 10, and the Surry Maintenance Rule Scoping and Performance Criteria Matrix, Rev. 11, with respect to the characterization of failures, the appropriateness of the associated a(1) or a(2) classification, and the appropriateness of either the associated a(2) performance criteria or the associated a(1) goals and corrective actions:

- S-2000-0792, PORV bottled air PCV failure;
- S-2000-0838, Damper 1-VS-MOD-100B failure; and,
- S-2000-0860, Fan 58A trip during testing.

b. Issues and Findings

There were no findings identified.

.2 System Implementation Reviews

a. Inspection Scope

The inspectors evaluated the effectiveness of the licensee’s maintenance rule program implementation for the containment instrument air system and the EDG fuel oil pumps. The inspectors checked for proper system scoping, monitoring, and categorization as required by the maintenance rule.

b. Issues and Findings

There were no findings identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's assessment of the risk impact of removing from service those components associated with the emergent work items listed below.

The inspectors reviewed the following emergent items to verify that the licensee had taken the necessary steps to demonstrate that emergent work activities were adequately planned and controlled to avoid initiating events, and to verify that the licensee ensured the functional capability of accident mitigation systems:

- 0-OPT-SW-003, Emergency Service Water Pump 1-SW-P-1C;
- PI S-2000-0822, Failure of Unit 1 Electrical Bus 1G;
- WO 431697-01, Reactor Protection Relay 27-2XB Replacement; and,
- WO 430763-01, Correct AMSAC Response to First Stage Pressure.

b. Issues and Findings

There were no findings identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors evaluated the technical adequacy of the operability evaluations to ensure that operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The operability evaluations were described in the engineering transmittal (ET) and PI listed below:

- ET-NAV-2000-0064 Rev. 0, 1-CH-P-1B Flow Shortfall Impact Upon Safety Analysis for Cycle 17, and
- PI-S-2000-120, Nonconforming Equipment Used for Weld Procedure Qualification Tests.

b. Issues and Findings

There were no findings identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the post maintenance test procedures and activities associated with the repair or replacement of the following components to determine that the procedures and test activities were adequate to verify operability and functional capability following maintenance of the following equipment:

- Unit 2 C Charging Pump (WO 419744-01, and 2-OPT-CH-003, “Charging Pump Operability and Performance Test,” Rev. 26);
- Unit 1 Train B RPS Auto Stop Oil Relay AST1-XB (WO 428949-01, and 1-PT-8.1, “Reactor Protection System Logic Test,” Rev. 20);
- Number 1 Emergency Diesel Generator (1-OPT-EE-009, “Number 1 Emergency Diesel Generator Major Maintenance Operability Test, Rev. 3”);
- Unit 2 Reactor Protection System (RPS) Relay 27-2XB Replacement (2-PT-8.1, “Reactor Protection System Logic Test,”); and,
- Unit 1 Pressurizer PORV Bottled Air Bank B Outlet Pressure Control Valve, (WO 430791-01 and 1-IMP-C-1A-100, “PCV-1456 Backup Bottled Air Instrumentation (High Pressure) Checkout,” Rev. 5).

b. Issues and Findings

There were no findings identified.

1R20 Refueling and Outage Activities (Unit 1)

.1 Routine Outage Activities

a. Inspection Scope

With respect to the Unit 1 refueling outage that began on April 16 and ended May 9, the inspectors used inspection procedure 71111.20, “Refueling and Outage Activities” to complete the inspections described below.

Prior to (and during) the outage, the inspectors reviewed the licensee’s outage risk control plan (“Unit 1 2000 Refueling Outage Safety Assessment,” Rev. 0-9 and VPAP-2805, “Shutdown Risk Program,” Rev. 3) to verify that the licensee had appropriately considered risk, industry experience and previous site specific problems, and to confirm that the licensee had mitigation/response strategies for losses of key safety functions.

During the cooldown which preceded the outage, the inspectors reviewed portions of the cooldown process to verify that technical specification cooldown restrictions were followed.

The inspectors confirmed that, when the licensee removed equipment from service, the licensee maintained defense-in-depth commensurate with the outage risk control plan for key safety functions and applicable technical specifications, and that configuration changes due to emergent work and unexpected conditions were controlled in accordance with the outage risk control plan.

For selected components which were removed from service, the inspectors examined clearance tags to verify that tags were properly hung and that associated equipment was appropriately configured to support the function of the clearance.

During the outage, the inspectors:

- Reviewed reactor coolant system (RCS) pressure, level, and temperature instruments to verify that those instruments were installed and configured to provide accurate indication; and that instrumentation error was accounted for;

- Reviewed the status and configuration of electrical systems to verify that those systems met technical specification requirements and the licensee's outage risk control plan;

- Observed decay heat removal (DHR) parameters to verify that the system was properly functioning;

- Observed spent fuel pool operations to verify that outage work was not impacting the ability of the operations staff to operate the spent fuel pool cooling system during and after core offload;

- Reviewed system alignments to verify that the flow paths, configurations, and alternative means for inventory addition were consistent with the outage risk plan;

- Reviewed selected control room operations to verify that the licensee was controlling reactivity in accordance with the technical specifications;

- Reviewed the outage risk plan to verify that activities, systems, and/or components which could cause unexpected reactivity changes were identified in the outage risk plan and were controlled accordingly;

- Observed licensee control of containment penetrations to verify that the licensee controlled those penetrations in accordance with the refueling operations technical specifications and could achieve containment closure for required conditions; and,

- The inspectors reviewed fuel handling operations to verify that those operations and related activities were being performed in accordance with technical specifications and approved procedures.

The inspectors reviewed the licensee's plans for changing plant configurations to verify on a sampling basis that technical specifications, license conditions, and other requirements, commitments, and administrative procedure prerequisites were met prior to changing plant configurations. The inspectors reviewed RCS boundary leakage and the setting of containment integrity. The inspectors examined the spaces inside the containment building prior to reactor startup to verify that debris had not been left which could affect performance of the containment sumps.

The inspectors reviewed various problems that arose during the outage to verify that the licensee was identifying problems related to refueling outage activities at an appropriate threshold and entering them in the corrective action program. The inspectors specifically reviewed the PIs listed below, because these were initiated during the refueling outage and were considered significant:

- S-2000-0786, Source Range N-32 Did Not Respond As Expected During Shutdown:
- S-2000-1104, B RSHX Manway Leak; and,
- S-2000-0871 Reactor Vessel Level Increase.

b. Issues and Findings

There were no findings identified.

.2 Anticipated Transients Without Scram Mitigation System Actuation Circuit (AMSAC) Failure to Arm Upon Plant Startup

a. Inspection Scope

The inspectors reviewed the licensee response and corrective actions implemented due to the failure of AMSAC to arm as expected when the plant was increasing power after the refueling outage.

b. Issues and Findings

On May 10, 2000, the operators were increasing plant power after Unit 1 was placed online when they noted that the AMSAC system failed to arm at 40 percent power as designed. The operators declared the system inoperable, entered a 30-day administrative limit and continued to increase power. Instrumentation and Control technicians investigated the failure and discovered that the electrical lead in the AMSAC panel from the turbine first stage pressure instrument (1-MS-PI-1446) was not connected. Further investigation revealed that this lead had been lifted during the refueling outage as part of test procedure 1-IPM-AMS-PNL-003, "AMSAC Logic Test," Rev. 6. This procedure contains a step to reconnect this lead, and requires an independent verification. There is no record of this lead being disturbed after the AMSAC Logic Test and prior to the failure of the system to arm. The lead was reconnected, post-maintenance testing was properly performed, and the AMSAC system was returned to service.

The inspectors reviewed the failure of the AMSAC system to arm using the Significance Determination (SDP) process. On the Surry plants, the AMSAC system is designed to shutdown the reactor by opening the rod drive motor-generator supply breakers, trip the main turbine, and start all the available auxiliary feedwater pumps. While this lead was lifted, the system would not have responded to anticipated transients without scram. This failure was assessed using the SDP process and the risk-informed inspection notebook for the Surry Power Station. With AMSAC inoperable for less than 8 hours and giving credit for operator recovery actions with procedures available, the failure was evaluated to be a Green finding.

Surry Power Station Technical Specifications, section 6.4.A.2 requires that detailed written procedures with appropriate check-off lists and instructions shall be provided for the calibration and testing of instruments, components, and systems involving nuclear safety of the station. Section 6.4.D requires that all procedures described in Specifications 6.4.A and 6.4.B shall be followed. Contrary to the above, the maintenance technicians failed to properly carry out step 6.4.5 of procedure 1-IPM-AMS-PNL-003, in that, they failed to reconnect the lead from the turbine first stage pressure instrument
(1-MS-PI-1446) and they failed to discover this error during the independent verification. The failure to meet the requirements of the technical specifications is identified as a violation of NRC requirements. However, this issue is considered a non-cited violation (NCV) (50-280/00003-01) consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee entered this issue in the corrective action system as PI S-2000-1186.

1R22 Surveillance Testing

a. Inspection Scope

For the surveillance tests listed below, the inspectors examined the test procedure and either witnessed the testing and/or reviewed test records to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable:

- 1-PT-8.1, “Reactor Protection System Logic (For Normal Operations),” Rev. 19, PAR 2;
- 0-OPT-VS-005, “Auxiliary Ventilation Filter Train Test,” Rev. 10;
- 1-OPT-SI-005, “LHSI Pump Test,” Rev. 12 OTO 1;
- 1-OPT-ZZ-001, “ESF Actuation with Undervoltage and Degraded Voltage - 1H Bus,” Rev. 13; and,

- 1-OPT-ZZ-002, “ESF Actuation with Undervoltage and Degraded Voltage - 1J Bus,” Rev. 13.

b. Issues and Findings

On April 18, 2000, during the performance of procedure 1-OPT-ZZ-002, filtered exhaust fans 1-VS-F-58A and B both tripped immediately after auto starting in response to a simulated safety injection signal. At the time of the event, Unit 1 was in a refueling outage and Unit 2 was operating at 100 percent power. The operator stationed at the ventilation panel reset the lockout signal on the 58B fan and the fan automatically started as designed. During subsequent testing activities, the licensee determined that safeguards suction damper 1-VS-MOD-100B was not indicating fully open. The damper was subsequently determined to be drifting closed. The damper was secured in the closed position until the damper could be repaired. The 58 fan flow control scheme had been modified by Design Change Package (DCP) 96-017 in November and December 1999, from suction pressure control to flow control. This increased the total system flow with two fans operating from approximately 36,000 cubic feet per minute (CFM) to 72,000 CFM. Following the design change each fan was tested separately but both fans were not tested in parallel operation. Based on this information the licensee placed one fan in pull-to-lock and entered a 7 day limiting condition of operation (LCO) on Unit 2 until further review and testing could be accomplished.

On April 19, the licensee performed procedure 1-OPT-ZZ-001. During the test both fans auto started on a simulated safety injection signal and the 58A fan tripped prior to achieving full flow. The 58B fan continued to run as designed. Engineering personnel observed ventilation system parameters during the April 19 test and determined that the modified fan control scheme would not allow parallel operation of both fans in the minimum safeguards alignment without one or both fans tripping. The licensee implemented a design change and a justification for continued operation to install new controller setpoints, operating procedure changes, and operator training to allow the system to be returned to service. The licensee completed these actions on April 23 and exited the 7 day LCO.

Under accident conditions, the auxiliary ventilation system is designed to: (1) reduce radiological releases by filtering air from the safeguards building and from specific areas of the auxiliary buildings; and, (2) provide air cooling for equipment, such as safety-related pumps, located in those areas. The auxiliary ventilation system is designed to be manually initiated during activities involving fuel movement if a safety injection signal occurs. Automatic actuation of the system is blocked by placing the system operating switches in the refuel mode. During other times the system automatically starts on a safety injection signal. The plant accident analysis assumes that ventilation is initiated within approximately 30 minutes (for filtration) following a design basis accident. The system controls are located in the main control room and the emergency operating procedures verify that at least one 58 fan is operating following a safety injection signal. The procedures recognize manual actuation of the system and sufficient time, 30 minutes, is available for the operators to perform the action. Based on this, the inspectors determined that this error would not have prevented the system from performing its safety functions and resulted in no measurable change in plant risk. In accordance with the SDP, the issue was determined to be more than minor. Since the plant design allowed time to manually actuate the system before equipment cooling is needed, the issue did not affect a reactor or radiological cornerstone. However, because of an extenuating circumstance, i.e., the issue was more than a minor violation, the finding is assigned a No Color.

10 CFR 50, Appendix B, Criterion III, requires in part that measures be established to ensure the design basis is correctly translated in specifications, drawings, procedures, and instructions. Contrary to the above, DCP 96-017 did not correctly translate the design basis of the auxiliary ventilation system into the design change instructions, in that, the modification as implemented did not allow parallel operation of both fans in the minimum safeguards alignment without one or both fans tripping following an actuation signal. The failure to meet the requirements of 10 CFR 50, Appendix B, Criterion III is identified as a violation of NRC requirements. However, this issue is considered an NCV (50-280, 281/00003-02) consistent with Section VI.A.1 of the NRC Enforcement Policy. The licensee entered this issue in the corrective action system as PI S-2000-0683 and initiated a category 1 root cause evaluation (RCE). The RCE had not been completed by the end of the inspection period.

(Closed) Licensee Event Report (LER) 50-280, 281/00001-00: Filtered exhaust fan failure results in technical specifications violation. This LER is closed based on inspection activities discussed in this section.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Modification S1-00-020, “Install Jumpers to Replace Relay FC-2XB,” to determine whether system operability/availability was affected, that configuration control was maintained, and that the associated safety evaluation (SE 00-069) adequately justified implementation.

b. Issues and Findings

There were no findings identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls

a. Inspection Scope

The inspectors reviewed the plant collective exposure history and the exposures incurred during the current Unit 1 refueling outage. ALARA planning and controls were reviewed for selected high dose jobs performed during the current Unit 1 outage and the previous Unit 2 outage. Implementation of ALARA controls and radiation worker performance for three high dose jobs performed during the Unit 1 outage were observed by the inspectors. Exposure tracking during the Unit 1 outage, records of exposures to declared pregnant workers during 1999 and year-to-date (YTD) 2000, and the source-term reduction program were also reviewed. The effectiveness of problem identification and resolution for selected ALARA related issues identified during 1999 and 2000 YTD was evaluated by the inspectors.

b. Issues and Findings

Over the past several years the licensee's three year mean collective dose per unit closely tracked the overall three year mean collective dose per unit for all pressurized water reactors, which has a decreasing trend. As of day 20 of the scheduled 26 day Unit 1 outage the cumulative outage dose was 68 Man-Rem and was on track for meeting the challenge goal of 74 Man-Rem.

There were no findings identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization

a. Inspection Scope

The inspectors reviewed licensee procedures, fitness for duty (FFD) reports, and licensee audits. Additionally, the inspectors interviewed representatives of licensee management and escort personnel concerning their understanding of the behavior observation portion of the personnel screening and FFD program. In interviewing these personnel, the inspectors reviewed the effectiveness of their training and abilities to recognize aberrant behavioral traits.

b. Issues and Findings

As of March 2000, a Virginia Power employee failed to report an arrest which occurred in December 1999, as required by the licensee's procedures.

Procedure VPAP-0105, “Fitness for Duty,” Rev. 13, implements the licensee’s FFD program. Section 6.8 of VPAP-0105 specifies individuals’ responsibilities to self-report FFD concerns, including all arrests (excluding certain traffic offenses). To self-report such concerns, the individual or supervisor is to utilize Attachment 5 of VPAP-0105, “Fitness for Duty/Self-Reporting Notification.” During a review of these reports for calendar year 2000, the inspectors determined that a Virginia Power employee failed to report an arrest which occurred in December 1999. A Self-Reporting Notification form was submitted by the individual’s supervisor in March 2000 based on information received by another employee. Upon interview by Virginia Power, the individual described the events which occurred, but stated that he/she was unaware that an arrest had occurred. The licensee’s subsequent investigation determined that the individual was arrested on misdemeanor charges, failed to report the arrest, and had been trained annually on the licensee’s self-reporting requirements.

The licensee’s mechanism to evaluate suitability for unescorted access is found in Procedure ASCP-0109, “Criteria for Unescorted Access Authorization,” Rev. 7. Adverse information is evaluated in accordance with Attachment 2, “Activity Classification.” Upon review of the individual’s charges and the failure of the individual to report the arrest, the inspectors determined that the licensee adjudicated the arrest change, but may not have considered the individual’s failure to report the arrest or admit upon questioning that the arrest occurred as a deliberate falsification, misrepresentation, or omission of material fact.

Pending further NRC review of the circumstances associated with this event, this finding is identified as an Unresolved Item (URI) 50-280, 281/00003-03.

3PP2 Access Control

a. Inspection Scope

The inspectors observed access control activities on April 25, 26, and 27, 2000, and equipment testing conducted on April 26, 2000. In observing the access control activities, the inspectors assessed whether officers could detect contraband prior to being introduced into the protected area. Additionally, the inspectors assessed whether the officers were conducting access control equipment testing in accordance with regulatory requirements through observation, review of procedures, and log entries.

b. Issues and Findings

The inspectors identified a non-cited violation for the failure to comply with the requirements of the physical security plan (PSP). On March 27 and April 26, 2000, the officer providing the last access control function did not remain isolated within a hardened structure to assure their ability to respond or to summon assistance.

On April 26, 2000, during observation of equipment testing at the secondary access portal (SAP), which is utilized during outages, the inspectors observed the final access control (FAC) officer outside the door of the hardened enclosure for several minutes, with his foot holding the door. The officer was resolving a problem with a visitor who was exiting the protected area. A short time later, during the continuation of access control testing, the inspectors observed the officer again leave the enclosure, except for his foot which was used to keep the door from locking. The officer's leaving the enclosure on two occasions, except for his foot to keep the door from locking, did not assure his ability to respond in accordance with the site PSP. Upon discovery by the inspector, the licensee initiated shift briefings to discuss the issue. The licensee determined that modifications to the SAP covered a badge drop-off window which resulted in the FAC officer leaving the enclosure to resolve access problems. The licensee determined that during peak egress periods, additional staffing may be necessary to handle administrative duties. A similar instance occurred on March 27, 2000, when the Primary Access Control FAC officer was removing trash and the door to the hardened enclosure locked behind him. Appropriate compensatory measures were implemented until the keys to the enclosure were located and the officer had returned to his post. At that time, shift briefings were completed stressing the FAC officer's responsibilities.

For both occurrences, the inspector noted that additional armed officers were located in the vicinity, and assessment capability still existed. In addition, there had not been additional similar findings in the previous four quarters; therefore, in accordance with the Physical Protection Significance Determination Process, these findings were considered to be of very low risk significance (Green) and within the licensee response band.

Condition 3.H of the Surry Operating License states, in part, that the licensee shall maintain in effect and fully implement all provisions of the Commission-approved PSP. The PSP, Section 3.3.3 establishes requirements for the individual responsible for the last access control function. The officers' failure to meet these requirements on March 27 and April 26, 2000, is a violation of the license and PSP. However, this issue is considered an NCV (50-280, 281/00003-04) consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as PI S-2000-1024.

4 OTHER ACTIVITIES

4OA5 Other

.1 Performance Indicator Data Collecting and Reporting Process Review

a. Inspection Scope (Temporary Instruction (TI) 2515/144)

The inspectors conducted a review of the licensee's performance indicator data collecting and reporting process to determine whether the licensee is appropriately implementing the NRC/industry guidance.

The inspectors reviewed the licensee's process for performance indicator data collection (using Operations Checklist OC-86, "NEI Performance Indicators (PI) Data Collection (Monthly)," Rev. 0, and HPAP 2802, "NRC Performance Indicator," Rev. 0, to determine if the system adequately collects data and accurately reports the following performance indicators:

- Unplanned Power Changes per 7,000 Critical Hours;
- Safety System Unavailability, High Pressure Injection System;
- Safety System Unavailability, Residual Heat Removal System;
- Safety System Functional Failures;
- Emergency Response Organization Drill Participation;
- Occupational Exposure Control Effectiveness; and,
- Protected Area Security Performance Index.

b. Issues and Findings

The "Safety System Unavailability, Emergency AC Power" and "Safety System Unavailability, Heat Removal System" performance indicator data for the years 1999 and the first quarter of 2000 contained unavailability hours for regularly scheduled surveillances. For these two performance indicators, the data collected for 1997 and 1998 did not contain planned maintenance hours for every case when equipment was taken out of service for regularly scheduled surveillance activities reflecting an inconsistency with the more current data. This complies with NRC/industry guidance for collecting historical data.

The licensee plans to modify the data collecting process for the "Safety System Unavailability, Emergency AC Power" performance indicator to remove the hours associated with overhaul and [a portion of] performance monitoring testing from the planned unavailability hours. The acceptability of the revised data collecting process will be evaluated the NRC.

The inspectors determined the licensee's current process for collecting and reporting performance indicator data is in accordance with the NRC/industry guidance.

.2 (Closed) Inspection Followup Item (IFI) 50-280, 281/99-03-04: review engineering's additional review and resulting actions to resolve containment liner corrosion. The licensee issued Engineering Transmittal (ET) MAT-99-0002, "Containment Liner to Floor Interface Evaluation," Rev. 0, on August 9,1999, to provide additional guidance for the evaluation of possible corrosion in crevice areas between the containment liner and the concrete floor. The ET addressed concerns raised by the inspectors with the licensee's 1998 evaluation of crevice areas on the Unit 1 containment liner. The inspectors were specifically concerned that the licensee had based their evaluation of crevice areas between the containment liner and the concrete floor on theoretical discussion without any select verification of the actual condition in the crevice area. Additional actions, such as excavation, were considered necessary to meet the requirements in 10 CFR 50.55a and ASME Article IWE. After further consideration the licensee engineers concluded that a more thorough assessment of the liner was advisable. Detail inspections were scheduled for those areas that visually exhibited the largest amount of corrosion and crevice width for the next outage of each Unit.

During the April refueling outage of Unit 1 the licensee selected 7 areas to excavate which represented various containment liner conditions. The extent of corrosion was based on the results of ultrasonic thickness measurements which were taken on the containment liner in the excavated areas. Subsequent to the Unit 1 excavations, the inspectors held discussions with the applicable civil engineer, reviewed pictures of the seven crevice areas excavated by the licensee between the concrete floor and the containment liner, and reviewed the ultrasonic results of the liner thickness in the excavated areas. The inspectors review of this documentation revealed that no appreciable amount of corrosion had taken place. Therefore, the actions taken by the licensee on Unit 1 were considered to meet the requirements of 10 CFR 50.55a and ASME Article IWE. The licensee has included this item on Unit 2 in their corrective action program (Commitment Tracking Item No. 4770) and Work Order 433274-01 has been issued to address discrepant liner conditions on Unit 2 that could require excavation during the fall 2000 refueling outage.

.3 (Closed) LER 50-280, 281/99003-00: potential loss of high head safety injection (HHSI) pumps due to postulated main control room (MCR) fire.

On March 31, 1999, a licensee fire protection integrated review determined that a postulated MCR fire could result in the loss of all Unit 1 and Unit 2 HHSI pumps. The pumps could be damaged by the depletion of both volume control tanks (VCTs) and the subsequent introduction of gas to the pumps' suction. The loss of all HHSI pumps would place the station outside its Appendix R design basis, in that, the loss of all HHSI pumps could result in the inability to achieve and maintain a safe shutdown condition. The circuitry for the automatic realignment of the pumps' suction from the VCT to the refueling water storage tank (RWST) was not protected from the effects of a fire and therefore, was not credited in the Appendix R Report analysis. Realignment of the Unit 1 and 2 HHSI pumps suction to the applicable RWST must be performed manually. Fire contingency action (FCA) procedure 0-FCA-1.00, "Limiting MCR Fire," Rev. 20, was in place to direct this realignment. However, the licensee determined that the procedure did not provide specific direction to ensure the alignment to the RWSTs was performed in time to preclude the depletion of both VCTs and a subsequent loss of all HHSI pumps. The licensee did not consider this postulated scenario during previous Appendix R reviews due to its complexity. The licensee issued DR S-99-0745 to document that the facility was outside its Appendix R design basis. The inadequate FCA procedure had existed since initial implementation of the licensee's Appendix R fire protection program. The licensee stated that procedure 0-FCA-1.00 was revised on April 1, 1999, to perform steps (i.e., manual positioning of valves, control switches and breakers) outside the MCR in time to prevent loss of HHSI on each unit. In addition, the revised FCA now directs the operators to protect the non-running HHSI pumps by placing them in "pull-to-lock" and realigning the pumps' suction to the RWST prior to evacuating the MCR. However, the licensee does not take credit for these MCR actions to mitigate the consequences of a MCR fire.

Factors that would mitigate the consequence of a MCR fire include: continuous manning of the MCR, wall-mounted fire extinguishers, and continuous monitoring by smoke/fire detectors. Additionally, the site maintains a minimum fire brigade at all times. Although credit is not taken for the automatic realignment of either unit's HHSI pumps suction from the VCT to the RWST in the Appendix R Report analysis, the likelihood of this capability in both units being damaged by a single fire is small and is discussed in the paragraph below. The circuitry for the automatic realignment is contained in panels that are approximately 25 feet apart. Either unit without fire damage would be able to supply HHSI to the other unit via the charging cross-connect, if necessary. The inspectors verified that the licensee has procedures in place to supply HHSI via the charging cross-connect capability.

The risk associated with the loss of all HHSI pumps is consistent with the licensee response band, in that, the increase in core damage frequency is estimated at less than 1E-6. A fire in the main control room growing beyond the incipient stage and propagating from panel 1-1 to 1-2, traveling approximately 25 feet and, then passing from panel 2-1 into 2-2 would be necessary to create the violation condition. Based upon information in the licensee's Individual Plant Examination of External Events, a fire of this nature would occur with a frequency of 3E-7/year. Using this frequency, the SDP analysis determined that the increase in core damage frequency would be less than 1E-6 and therefore is a Green finding. The fire initiating event frequency was derived from:

> (1.9E-2 fires/year in the control room) ✱ (0.0025 probability that the control room fire was in cabinet 1-1 and it propagates into cabinet 1-2) ✱ (0.077 probability fire propagates to cabinet 2-1) ✱ (0.077 probability fire propagates to cabinet 2-2) = 3E-7.

10 CFR 50.48, "Fire Protection," states, in part, that each operating nuclear plant licensed to operate prior to January 1, 1979, shall satisfy the requirements of 10 CFR 50, Appendix R, Section III.G. Both Surry units were licensed prior to January 1, 1979. 10 CFR 50, Appendix R, Item III.G.3 requires that alternative or dedicated shutdown capability shall be provided. The means of providing alternative or dedicated shutdown capability is specified in 10 CFR 50, Appendix R, Section III.L. Section III.L.3, states, in part, that procedures shall be in effect to implement the alternative shutdown capability. Surry utilizes FCA procedures to implement the station's alternative shutdown capability. The failure to have an adequate procedure in effect to provide alternative shutdown capability (i.e., to achieve and maintain a safe shutdown condition) in the event of a MCR fire is a violation of 10 CFR 50, Appendix R, Section III.L.3. However, this issue is considered an NCV (50-280, 281/00003-05) consistent with Section VI.A.1 of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as DR S-99-0745.

.4 Transnuclear (TN)-32 Spent Fuel Cask Low Pressure Alarms

a. Inspection Scope (60855)

The inspectors reviewed the licensee response and corrective actions implemented due to low pressure alarms associated with TN-32 spent fuel storage cask 2-3 located at the Surry Independent Spent Fuel Storage Installation (ISFSI).

b. Observations and Findings

On April 20, 2000, a low pressure alarm was received at the ISFSI on cask 2-3. The licensee initiated troubleshooting efforts and determined that the alarm was valid. The licensee entered a 30 day administrative limit to determine the cause of the low pressure alarm and effect repairs. The licensee had a similar low pressure alarm on cask 2-3 on March 21, 2000, and replaced a leaking pressure switch and returned the cask to normal operation.

The licensee used a helium detector and identified pressure switch diaphragm leakage. Based on the identified source of helium leakage, the licensee depressurized the helium overpressure system and replaced both pressure switches associated with the helium overpressure system. The activity was accomplished in accordance with procedure 0-OP-FH-063, “Replacing a Pressure Switch on a TN-32 Dry Storage Cask,” Rev. 0. The cask was returned to normal operation on April 25, 2000, and the 30 day administrative limit was exited.

On May 31, 2000, a low pressure alarm was again received on cask 2-3. The licensee initiated troubleshooting efforts and determined that the alarm was valid. The licensee again determined that the overpressure system pressure switches were leaking however based on the time frame of the pressure reduction in the overpressure system, the licensee decided to return the cask to the decontamination building for further troubleshooting.

The licensee removed the overpressure tank and performed pressure drop tests on the overpressure tank and the cask seal area. The testing determined that the cask outer seal was suspect. The licensee also identified that a portion of the coating on the cask lid had failed and that corrosion and rust had developed in the area where the coating had failed. On June 15, 2000, the licensee returned the cask to the spent fuel pool and unloaded the cask. The unloaded cask was returned to the decontamination building for further troubleshooting. As of the end of the inspection period, the licensee had not completed the root cause evaluation of the cask low pressure alarms.

c. Conclusions

The inspectors monitored licensee troubleshooting efforts on the loss of helium from cask 2-3 overpressurization system, and observed the return of the cask to the spent fuel pool, cask reflood, and portions of the cask unloading sequence. Cask activities were accomplished in accordance with approved procedures.

4OA6 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 23, 2000. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

M. Adams, Superintendent, Engineering
R. Allen, Superintendent, Maintenance
R. Blount, Manager, Operations & Maintenance
M. Crist, Superintendent, Operations
E. Grecheck, Site Vice President
D. Llewellyn, Superintendent, Training
T. Sowers, Manager, Station Safety & Licensing
B. Stanley, Supervisor, Licensing
J. Swientoniewski, Director, Nuclear Oversight
W. Thornton, Superintendent, Radiological Protection

ITEMS OPENED AND CLOSED

Opened

50-280, 281/00003-03	URI	Virginia Power employee failure to report arrest in accordance with VPAP-0105 (Section 3PP1).

Opened and Closed During this Inspection

50-280/00003-01	NCV	Failure to follow AMSAC logic test procedure (Section 1R20.2).
50-280, 281/00003-02	NCV	Inadequate Auxiliary Ventilation Modification (Section 1R22).
50-280, 281/00003-04	NCV	Failure to comply with the requirements of the Physical Security Plan (Section 3PP2).
50-280, 281/00003-05	NCV	Failure to have an adequate procedure to provide alternative shutdown capability (Section 4OA5.3).

Closed

50-280, 281/00001-00	LER	Filtered exhaust fan failure results in technical specification violation (Section 1R22).
2515/144	TI	Performance Indicator Data Collecting and Reporting Process Review (Section 4OA5.1).

50-280, 281/99-03-04	IFI	Review engineering's additional review and resulting actions to resolve containment liner corrosion (Section 4AO5.2).
50-280, 281/99003-00	LER	Potential Loss of High Head Safety Injection Pumps due to Postulated Main Control Room Fire (Section 4OA5.3).

LIST OF ACRONYMS USED

AC	alternating current
ALARA	as low as is reasonably achievable
AMSAC	ATWS mitigation system actuation circuit
ASME	American Society of Mechanical Engineers
ATWS	anticipated transients without scram
CFM	cubic feet per minute
CFR	code of federal regulations
DCP	design change package
DHR	decay heat removal
DR	deviation report
EDG	emergency diesel generator
ESF	engineered safeguards feature
ET	engineering transmittal
FAC	final access control
FCA	fire contingency action
FFD	fitness for duty
HHSI	high head safety injection
IFI	inspection followup item
ISFSI	independent spent fuel storage installation
ISI	inservice inspection
LCO	limiting condition of operation
LER	licensee event report
LHSI	low head safety injection
MCR	main control room
NCV	non-cited violation
NRC	Nuclear Regulatory Commission
OTO	one time only
PAR	procedure action request
PCV	pressure control valve
PI	plant issue
PORV	power operated relief valve
PSP	physical security plan
RCE	root cause evaluation
RCS	reactor coolant system
Rev	revision
RHR	residual heat removal
RPS	reactor protection system
RSHX	recirculation spray heat exchanger
RWST	refueling water storage tank
SAP	secondary access portal
SDP	significance determination process
SPS	Surry Power Station
TI	temporary instruction
TN	Transnuclear
URI	unresolved item
VCT	volume control tank
YTD	year-to-date

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	**Radiation Safety**	**Safeguards**
• Initiating Events • Mitigating Systems • Barrier Integrity • Emergency Preparedness	• Occupational • Public	• Physical Protection

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.