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REGION II

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Report Nos.: 50-280/99-07, 50-281/99-07

Licensee: Virginia Electric and Power Company (VEPCO)

Facility: Surry Power Station, Units 1 & 2

Location: 5850 Hog Island Road
Surry, VA 23883

Dates: September 26 - November 6, 1999

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Enclosure

EXECUTIVE SUMMARY

Surry Power Station, Units 1 & 2
NRC Integrated Inspection Report Nos. 50-280/99-07, 50-281/99-07

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by a regional security specialist and a corrective action team.

Operations

- A loss of power to the 1H and 2J emergency busses due to a lockout of the C reserve station transformer caused emergency diesel generators (EDGs)1 and 3 to automatically start and supply power to the emergency busses. The EDGs operated successfully in this condition for two days until the transformer was returned to service (Section O1.2).

- A non-cited violation was identified for failure to report an engineered safety feature actuation within the 4-hours required by 10CFR50.72. This involved emergency diesel generator automatic initiations due to a loss of voltage on the 1H and 2J emergency busses (Section O1.2).

- The Unit 2 containment spray system was properly aligned and in generally good condition (Section O2.1).

- Two of six Category 1 or 2 root cause evaluations (RCEs) reviewed by the inspectors were for failures that had occurred before and had earlier root-cause evaluations performed on them. In addition, for these RCEs, the licensee root-cause investigation teams had not initiated actions to determine what caused the earlier RCEs to be ineffective (Section O7.1).

- The licensee's Deviation Reporting and Corrective Action Programs for Category 3 root cause evaluations were adequate for identification, assessment and resolution of conditions potentially adverse to quality (Section O7.2).

- Corrective actions for the power operated relief valve back up air supply system, while in (a)(1) status since 1997, have not been effective in improving system performance and troubleshooting efforts are ongoing. An unresolved item was opened to review compliance with 10 CFR 50 Appendix B Criterion XVI, "Corrective Action" (Section O7.3).

- Overall, the licensee's Operating Experience Program was adequate; however, several operating experience items were open for long periods of time (some approximately 11 years) and the licensee was not tracking these items as overdue (Section O7.4).

- In general, the commitment tracking system (CTS) effectively monitored the progress and closure of corrective action items. A random sample of specific items indicated that the items were being adequately tracked, addressed, and due date extensions were approved in accordance with plant procedures. A weakness was noted in the CTS

tracking system, in that, no controls were in place to identify items which are overdue while in the licensing group's review process. Specifically, four items exceeded the 30 days allowed for the licensing group's review but were not being tracked nor were they identified in weekly management reports as overdue (Section O7.5).

- The reviewed activities of the oversight committees comply with the requirements of the technical specifications and the governing procedures. However, the Management Safety Review Committee identified a concern with the foreign material exclusion program in three consecutive meetings without amplifying discussion in the minutes or opening an action item (Section O7.6).

- A non-cited violation was identified for emergency diesel generator 3 being inoperable longer than the technical specification allowed outage time (Section O8.1)

Maintenance

- Periodic tests for the intake canal level probe inspection and low head safety injection pumps were properly performed. The tests were approved by station management, performed by knowledgeable workers, and technical specification surveillance requirements were satisfied. A non-cited violation was identified for failure to perform all required post maintenance testing prior to returning the Unit 2 A low head safety injection pump to operable status (Section M1.1).

- Maintenance activities which included lubrication and inspection of the containment spray and low head safety injection pumps were properly performed. Personnel conducting the activities were knowledgeable and followed work package instructions. A tagout on the containment spray system was properly implemented (Section M1.2).

Engineering

- A low number of temporary modifications (six) were installed on Units 1 and 2. The safety evaluation associated with Unit 2 temporary modification S2-99-07 for the removal of the reactor coolant loop isolation valve 2-RC-2591 disc adequately justified implementation of the modification (Section E1.1).

Plant Support

- Based on alarm station operations in the areas of access control, intrusion detection, monitoring of alarms, and communication capabilities, the inspectors concluded that the Central and Secondary Alarm Stations' functions and communications systems were effective and met regulatory requirements specified in the Physical Security Plan and implementing procedures (Section S1.2).

- The licensee's access control program was effective in ensuring that favorably terminated employees' badges were deactivated in accordance with the Physical Security Plan and implementing procedures (Section S1.3).

- The licensee was testing and maintaining security related equipment as required by the Physical Security Plan and implementing procedures. Security related equipment was being repaired in a timely manner (Section S2.1).

- Compensatory measures observed and reviewed through documentation met the requirements outlined in the Physical Security Plan (Section S2.2).

- Revision 5 of the Physical Security Plan was appropriately submitted under the provisions of 10 CFR 50.54(p) (Section S3.1).

Report Details

Summary of Plant Status

Unit 1 and Unit 2 operated at power the entire reporting period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations and reviewed operator logs to verify operational safety and compliance with Technical Specifications (TSs). Instrumentation and safety system lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status and housekeeping. Deviation reports (DRs) were reviewed to assure that potential safety concerns were properly reported and resolved. The inspectors found that daily operations were generally conducted in accordance with regulatory requirements and plant procedures.

O1.2 C Reserve Station Service Transformer (RSST) Lockout

a. Inspection Scope (71707)

The inspectors reviewed licensee actions associated with a C RSST lockout signal resulting in Emergency Diesel Generator (EDG) 1 and EDG 3 automatically starting and assuming load on the 1H and 2J emergency busses.

b. Observations and Findings

On October 9, 1999, at 12:34 p.m. multiple overvoltage alarms were received in the Unit 1 and 2 control room associated with emergency busses 1H and 2J. Operators dispatched to the C RSST observed arcing and small flames from cable connections adjacent to the Unit 2 turbine building. These cables supply power from the C RSST to the emergency busses. At 12:41 p.m. a transformer lockout occurred on C RSST resulting in a loss of power to Unit 1 emergency buss 1H and Unit 2 emergency buss 2J. The loss of power resulted in an automatic start of EDG 1 and EDG 3 and re-energization of the emergency busses from their associated EDG. Both units remained at power while the C RSST was out of service.

The inspectors were notified of the problem with the C RSST and responded to the site. The response of each unit to the loss of the C RSST was as expected. The inspectors observed that both operating EDGs were stable and maintaining proper voltage and frequency on the associated emergency buss. The licensee initiated walkdowns of the operating EDGs on a 30-minute frequency and the inspectors also monitored operation of the EDGs. Operation in this condition was anticipated for an extended period of time

based on the estimated time to repair the failed cable connection. The inspectors verified that adequate diesel fuel oil was available onsite to allow operation of the EDGs for an extended period of time. Diesel fuel availability remained above the minimum level specified in TS 3.16.A.1 throughout the two day time period that the EDGs were supplying power to the emergency busses.

The inspectors reviewed the TSs, emergency plan, and reportability requirements associated with the event. TS requirements were being met and the emergency plan did not require entry into an emergency classification. The inspectors discussed the reportability requirements with the operating crew and the shift technical advisor. The inspectors were informed that the previous shift had determined that the event was not reportable under 10CFR50.72. The inspectors questioned the reportability determination based on the fact that degraded voltage/loss of voltage is identified as an engineered safety feature (ESF) signal in TS Table 3.7-4. The operating crew agreed to review the previous reportability determination. The licensee subsequently determined that the event was reportable as an ESF actuation under 10CFR50.72(b)2(ii) and notified the NRC operations center at 10:13 p.m. of the ESF actuation. The failure to report an ESF actuation within 4 hours is identified as a violation of 10CFR50.72. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as DR S-99-2415 and is identified as NCV 50-280, 281/99007-01.

The C RSST was repaired and returned to service on October 11, 1999, at 11:32 a.m. The licensee repaired the cable connection that faulted, inspected 10 other cable connections similar to the faulted connection and replaced the associated raychem insulation on the inspected connections. The licensee did not identify any indications of faulted conditions on the inspected cable connections. EDG 1 was secured and returned to automatic at 12:35 p.m. and EDG 3 was secured and returned to automatic at 2:13 p.m. The inspectors monitored the return to service of the C RSST and return of offsite power to the 1H and 2J emergency busses. The evolutions were well controlled and accomplished in accordance with approved procedures.

c. Conclusions

A loss of power to the 1H and 2J emergency busses due to a lockout of the C reserve station transformer caused emergency diesel generators (EDGs)1 and 3 to automatically start and supply power to the emergency busses. The EDGs operated successfully in this condition for two days until the transformer was returned to service.

A non-cited violation was identified for failure to report an engineered safety feature actuation within the 4-hours required by 10CFR50.72. This involved emergency diesel generator automatic initiations due to a loss of voltage on the 1H and 2J emergency busses.

O2 Operational Status of Facilities and Equipment

O2.1 Unit 2 Containment Spray (CS) System

a. Inspection Scope (71707)

The inspectors performed a walkdown of the Unit 2 containment spray system.

b. Observations and Findings

The inspectors performed a walkdown of accessible components associated with the Unit 2 containment spray system. The walkdown encompassed the pump suction piping from the refueling water storage tank, the chemical addition system, and the pump discharge piping up to the containment penetrations. The inspectors referenced the system piping and instrument diagrams and procedure 2-OP-CS-001A, "Containment Spray System Alignment," for proper system alignment and component descriptions.

The inspectors checked system hangers and supports, valve positions, labeling and general housekeeping. The inspectors determined that the system was properly aligned and in generally good condition. The inspectors verified that the valve alignment procedures adequately aligned the system.

c. Conclusions

The Unit 2 containment spray system was properly aligned and in generally good condition.

O7 Quality Assurance in Operations

O7.1 Root Cause Evaluation Review

a. Inspection Scope (40500)

The inspectors reviewed six licensee-prepared Root Cause Evaluations (RCEs). Four of the reviewed RCEs were classified as Category 1 (investigations of the most significant issues), and two RCEs were classified as Category 2 (investigations of the next most significant issues).

b. Observations and Findings

Several observations were noted during the RCE review. Several RCEs did not identify the analysis technique(s) that were used to identify the root and contributing causes. These RCEs provided discussions which clarified and/or expanded the problem statements in some way, but none explained how the root and contributing causes were

identified. Similarly, none of the RCEs explained how implementation of the recommended corrective actions addressed the root and contributing causes. The inspectors examined VPAP-1604, "Root Cause Evaluation Program," Revision 2, which is the licensee's procedure for conducting RCEs. The procedure did not specifically require that the analysis techniques used or how the corrective actions would address the root and contributing causes be identified or documented. The inspectors discussed this and several other observations regarding the procedure's content with the licensee.

The inspectors also reviewed the licensee's follow up actions into the failures of previous investigations to determined the actual cause(s) of an event. Specifically, while preparing RCE 98-1182 (problems with returning EDGs to service after maintenance outages), the licensee's investigation team members noted that RCE 98-0387 had not adequately addressed the problem. RCE 98-1182 stated that "approved corrective actions to prevent recurrence were not effective," and that "the corrective actions from the previous RCE ... were narrowly focused and did not address the work process controls and procedure inadequacies." However, the licensee did not initiate a DR to capture the previous inadequate root cause evaluation and examine what failed in their process to determine the correct root cause(s). The inspectors noted a similar finding in RCE 98-1189, which was associated with the Unit 1 main turbine not tripping from the control room manual pushbuttons. RCE 98-1189 stated that "the failure to trip the turbine from the control room was a previously identified problem and the subject of a Category 2 Root Cause Evaluation." Since 1990 the Unit 1 turbine has failed to trip at least seven times from the control room pushbuttons. The licensee's investigation team did not initiate a DR to review the effectiveness of earlier RCEs. The inspectors determined that these types of issues, i.e., why earlier RCE efforts had not resolved the problems and prevented recurrence, should be addressed by the licensee's corrective action program. The licensee subsequently entered this issue into their corrective action program as Plant Issue S-99-2580.

c. Conclusions

Two of six Category 1 or 2 root cause evaluations (RCEs) reviewed by the inspectors were for failures that had occurred before and had earlier root-cause evaluations performed on them. In addition, for these RCEs, the licensee root-cause investigation teams had not initiated actions to determine what caused the earlier RCEs to be ineffective.

O7.2 Deviation Reporting and Corrective Action Program

a. Inspection Scope (40500)

The inspectors assessed the licensee's Deviation Reporting and Corrective Action Programs that are addressed by Category 3 root causes (lowest level of significance). This assessment included review of licensee procedures, interviews with Station Nuclear Safety personnel, and review of selected open DRs, repeat DRs, and completed DRs.

b. Observations and Findings

The inspectors reviewed two Station Administrative Procedures VPAP-1501, "Deviations," Revision 12, and VPAP-1601, "Corrective Action," Revision 11. The inspectors determined that DRs were properly reviewed for operability/reportability, significance levels were appropriately classified, and RCE category levels were correctly assigned. The inspectors verified that corrective actions for DRs associated with RCE Category 3 were properly reviewed, approved, and implemented in accordance with procedural requirements.

During review of Attachment 1 of VPAP-1501 the inspectors noted that the shift supervisor is given the option to select the operability of equipment as "unknown." Contained within the attachment, under the initial reportability/operability review section, a question asks, "Is the system/component inoperable?" The inspectors noted that in a DR involving the status of the safety-related batteries, the shift supervisor completed the operability block as unknown. The inspectors noted also during this review that no specific time limits were associated with the operability determination once the initial screening is completed. The inspectors concluded that the licensee's process allowed a selection of an unknown operability yet no time constraints are given for completion of the operability determination. The inspectors noted that this procedure allowance is not consistent with the guidance of Generic Letter 91-18, "Information To Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions," Revision 1, in that, GL91-18 contains guidance on the timeliness of operability determinations. The licensee indicated plans to review this issue further.

c. Conclusions

The licensee's Deviation Reporting and Corrective Action Programs for Category 3 root cause evaluations were adequate for identification, assessment and resolution of conditions potentially adverse to quality.

O7.3. Maintenance Rule (a)(1) Corrective Actions

a. Inspection Scope (40500)

The inspectors reviewed the systems in maintenance rule (a)(1) status and their associated corrective actions.

b. Observations and Findings

The inspectors reviewed licensee established goals, monitoring periods, and corrective actions for Systems, Structures, or Components (SSCs) in the maintenance rule (a)(1) status. At the time of this review 22 systems were in (a)(1) status.

The inspectors reviewed the backup supply air system for power operated relief valves (PORVs) and associated failures that caused a PORV to be inoperable. The system

was placed in (a)(1) status on February 20, 1997, after it exceeded its allowed failure rate. At the time of the inspection, corrective actions included a procedure revision for the method of filling the PORV compressed-air bottles, replacement of fittings and establishing preventative maintenance to periodically replace backup air regulators. All these corrective actions were not completed as scheduled and extension requests were not processed through the Surry Maintenance Rule Working Group prior to exceeding the due dates. These corrective actions were established and scheduled to be implemented to remove the system from (a)(1) status. Through a further review of the system's performance, the inspectors learned that the back up supply system has had seven instances where either fitting leaks, regulator valve seats failures, or incorrect regulator valve adjustments resulted in lost of air pressure or degradation of the system. These problems have occurred on both units. These system problems were initially documented in 1996, and continued through 1997 and 1998. Troubleshooting efforts are ongoing and the system remains in (a)(1) status. Additional NRC review is required to determine if the licensee has complied with 10 CFR 50 Appendix B Criterion XVI, "Corrective Action." Pending this additional review, this item is identified as unresolved item (URI) 50-280, 281/99007-02.

The inspectors noted an additional concern regarding systems in (a)(1) status. The plant computer system is currently in (a)(1) status and based upon the current schedule will remain in (a)(1) for approximately five years. The inspectors expressed concern to the licensee that maintaining a system in this status for that length of time may dilute the effectiveness of placing a system in (a)(1). The inspectors also discussed with the Maintenance Rule Coordinator and licensee management the appropriateness of not implementing stated corrective actions and the changing of due dates. The inspectors learned that the licensee is not specifically required by the maintenance rule procedure VPAP-0815, "Maintenance Rule Program," Revision 10, to address due dates prior to the interim goals or corrective action dates being exceeded. As a result of the discussions, the licensee plans to revise this procedure to address the process that maintenance rule system engineers use to request changes to due dates. The inspectors also learned that the licensee has captured this issue in their maintenance rule system health report as a degraded condition and that the current window status for implementation of corrective action for (a)(1) systems is yellow. Windows are classified from green, white, yellow, and red in descending order of performance.

c. Conclusions

Corrective actions for the power operated relief valve back up air supply system, while in (a)(1) status since 1997, have not been effective in improving system performance and troubleshooting efforts are ongoing. An unresolved item was opened to review compliance with 10 CFR 50 Appendix B Criterion XVI, "Corrective Action."

O7.4 Operating Experience Program

a. Inspection Scope (40500)

The inspectors assessed the Operating Experience (OE) Program. This assessment included review of Station Administrative Procedure, VPAP-3002, "Operating Experience Program," Revision 8, interviews with Surry and Corporate OE Coordinators, attendance of a weekly significant information focus team conference call, review of the industry operating experience review (IOER) database, review of selected OE issues, and review of an OE program self-assessment.

b. Observations and Findings

The inspectors determined that procedure VPAP-3002 provided appropriate guidance to implement the OE program. Coordinators were knowledgeable of the OE process, procedure requirements and their responsibilities. The inspectors noted that current IOER database is being transferred into the new OE Corrective Action System to improve tracking of OE reviews. The inspectors determined that industry experiences and in-house issues (e.g., Licensee Event Reports, Notices of Violations, Non-Cited Violations, Category 1 RCEs) were received in a timely manner, properly screened, evaluated, distributed, and tracked for resolutions in accordance with procedural requirements. Based on review of the licensee's 1998 OE self-assessment, the inspectors noted that the licensee is identifying and appropriately addressing issues. The inspectors noted that there were no OE issues with past due dates, but several OE issues remained open for long periods of time. Specifically two OE items that were approximately 11 years old (i.e., Generic Letter 88-15 and Information Notice (IN) 88-45) had not been closed. Additional examples of old open OE items included IN 92-69, and Westinghouse Vendor Notice 94-18. The inspectors concluded that a review of such items provide little if any value to the licensee this long after the issue was initially identified. The licensee indicated plans to review the OE item tracking system.

c. Conclusions

Overall, the licensee's Operating Experience Program was adequate; however, several operating experience items were open for long periods of time (some approximately 11 years) and the licensee was not tracking these items as overdue.

O7.5 Commitment Tracking System (CTS)

a. Inspection Scope (40500)

The inspectors reviewed the commitment tracking system to assess the timeliness and effectiveness of corrective actions to prevent recurrence and verify that any delayed items were appropriately addressed.

b. Observations and Findings

The inspectors reviewed and noted that management reports on the status of licensing issues (in-house) indicated that no CTS responses were overdue. The inspectors noted that licensing was allotted thirty days for their internal review after a response had been submitted by the responsible department. However, the inspectors identified four items that were still open and had been in this review process in excess of thirty days. These items were not included in the backlog reports because they had been submitted by the responsible department within the time frame allotted and were considered to be in the 30 day licensing review. The inspectors determined that there were no controls to identify items which are overdue while in the licensing group's review process. Once these four late items were identified, licensing was able to resolve each of the delinquent CTS items.

The inspectors reviewed CTS items due to be completed and provided to licensing within the previous month. All in-house commitments had been properly closed or extended. All of the extensions were reasonable and were properly authorized in accordance with plant procedures. Deviation reports tied to CTS items were also reviewed and verified as properly incorporated into the tracking system.

c. Conclusions

In general, the commitment tracking system (CTS) effectively monitored the progress and closure of corrective action items. A random sample of specific items indicated that the items were being adequately tracked, addressed, and extension of dues date were approved in accordance with plant procedures. A weakness was noted in the CTS tracking system, in that, no controls were in place to identify items which are overdue while in the licensing group's review process. Specifically, four items exceeded the 30 days allowed for the licensing group's review but were not being tracked nor were they identified in weekly management reports as overdue.

O7.6 Onsite and Offsite Review Committee Activities

a. Inspection Scope (40500)

The inspectors reviewed the minutes of selected meetings and Nuclear Oversight Department reports to evaluate the effectiveness of the onsite and offsite review committees

b. Observations and Findings

The inspectors reviewed the meeting minutes for the offsite review committee (Management Safety Review Committee) to verify TS requirements were being met. The inspectors verified that the committee reviewed the NCVs and LERs issued in the past year and that the required audits were being performed and reviewed by the committee. The inspectors identified that the committee raised concerns about the

foreign material exclusion program in three consecutive meetings without any discussion noted, open item issued, or related topics added to the agenda for a future meeting.

The inspectors also reviewed the minutes for meetings of the onsite review committee (Station Nuclear Safety and Operating Committee) held during the period from July to September 1999. The inspectors noted that the minimum required meetings were being held, that proper issues were being addressed, and that the committee was actively pursuing enhancements to ensure that the important issues were being addressed.

c. Conclusions

The reviewed activities of the oversight committees comply with the requirements of the technical specifications and the governing procedures. However, the Management Safety Review Committee identified a concern with the foreign material exclusion program in three consecutive meetings without amplifying discussion in the minutes or opening an action item.

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) Licensee Event Report (LER) 50-281/99004-00: EDG inoperable longer than allowed by TS due to governor compensation valve. During EDG 3 post maintenance testing on November 5 and 6, 1998, the EDG governor load response characteristics were abnormal. The licensee evaluated the governor operation as acceptable for emergency operation but degraded for parallel operation with the grid and returned the EDG to an operable status on November 7, 1998. The licensee subsequently replaced the governor on November 10, 1998, and sent the governor to the vendor for testing. On September 9, 1999, based on vendor testing of the EDG governor, the licensee determined that the governor would not have maintained the correct speed during emergency operation. The cause of the governor failure was identified as the compensation valve being shut. The licensee was unable to determine how the compensation valve became shut. The last maintenance associated with the governor occurred on August 12, 1998, when the governor compensation had been adjusted and tested. Subsequent routine testing did not identify any problems with governor response. The inspectors determined that on October 12, 1998, following EDG maintenance activities, EDG 3 was started and loaded on the de-energized emergency buss as part of required refueling outage testing. The EDG maintained proper voltage and frequency during the test. On November 2, 1998, a routine EDG surveillance was performed and no discrepancies were identified with governor response, however, maintenance was required to repair the EDG excitation cabinet.

Based on the vendor test results the licensee determined that EDG 3 had been inoperable from November 2, 1998, when the excitation cabinet failure occurred until November 10, 1998, when the governor was replaced. TS 3.16.B allows an EDG to be inoperable for a period not to exceed 7 days provided certain compensatory actions are met. During this event, EDG 3 was inoperable for a period of approximately 8 days and 18 hours. EDG 3 was not required for Unit 1 since it was in a refueling outage during this time. However, Unit 2 was at power during the period. The failure to meet the

requirements of TS 3.16.B for Unit 2 is identified as a violation. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as DR S-99-2253 and is identified as NCV 50-281/99007-03.

O8.2 (Closed) LER 50-280/98013-00, 01: Turbine/Reactor trip on high steam generator level due to instrument failure. This item was discussed in NRC Inspection Report No. 50-280/98-09. The inspectors reviewed the corrective actions and found them adequate.

O8.3 (Closed) LER 50-280/98014-00: Manual reactor trip in response to main feedwater regulating valve failure. This item was discussed in NRC Inspection Report No. 50-280/98-09. The inspectors reviewed the associated DR and root cause evaluation and found the licensee's corrective actions adequate.

O8.4 (Closed) LER 50-281/99003-00: Auto reactor trip on low coolant flow due to loop stop valve failure. This item was discussed in NRC Inspection Report No. 50-281/99-05 and resulted in an NCV being issued for failure to refill the condensate storage tank within 2 hours as required by TSs. The inspectors verified that corrective actions had been completed or were being tracked in the licensee corrective action program.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Periodic Test (PT) Observations

a. Inspection Scope (61726)

The inspectors observed portions of the following PTs being performed:

- 0-NSP-CW-001 High Level Intake Structure Canal Level Probe Inspection
- 2-OPT-SI-005 Low Head Safety Injection Pump Test

b. Observations and Findings

The inspectors verified that the tests were properly approved by management and included on the plan of the day. The inspectors checked selected components for their pre-test and post-test positions to ensure that they were properly positioned and no discrepancies were identified. The inspectors checked test instrument calibration tags to ensure the due dates had not been exceeded. The inspectors also reviewed the test acceptance criteria to ensure they were consistent with TS requirements. The inspectors reviewed selected test data after the completion of the test to ensure component performance was satisfactory.

Procedure 2-OPT-SI-005 was performed as both a post maintenance test (PMT) on the Unit 2 A low head safety injection (LHSI) pump and a quarterly surveillance for both LHSI

pumps. During the procedure, based on a verbal report that the PMT was complete, the Senior Reactor Operator declared the A LHSI pump operable. Later in the procedure, prior to securing the A LHSI pump, the electricians at the motor requested that the pump not be secured until additional data could be taken. The inspectors questioned the need for the data and the resulting licensee investigation identified that this last set of data was required prior to the completion of the PMT on the A LHSI pump. At this point, operations personnel determined that for a period of three minutes, neither LHSI pump had been operable. The A LHSI pump had been improperly declared operable while at the same time the B LHSI pump was temporarily rendered inoperable when its recirculation flowpath was isolated. A subsequent review by the licensing department determined that because the A LHSI pump successfully passed the PMT and was capable of performing its safety-related function, the pump was operable and the event was not reportable.

TS 6.4.A.7 requires that detailed written procedures with appropriate check-off lists and instructions shall be provided for preventive or corrective maintenance operations which would have an effect on the safety of the reactor. TS 6.4.D requires that all procedures described in TS 6.4.A shall be followed. Section 6.14.2 of Virginia Power Administrative Procedure (VPAP) 0801, "Maintenance Procedures," Revision 7, requires that following maintenance and post maintenance testing, the functional acceptability of affected equipment shall be documented before being declared operable and that completed work instruction package shall be reviewed and signed off by appropriate personnel. The failure to properly complete the PMT prior to declaring the A LHSI pump operable is identified as a violation of TS 6.4.D. This Severity Level IV violation is being treated as an NCV, consistent with Section VII.B.1.a of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as DR S-99-2369 and is identified as NCV 50-281/99007-04.

c. Conclusions

Periodic tests for the intake canal level probe inspection and low head safety injection pumps were properly performed. The tests were approved by station management, performed by knowledgeable workers, and technical specification surveillance requirements were satisfied. A non-cited violation was identified for failure to perform all required post maintenance testing prior to returning the A low head safety injection pump to operable status.

M1.2 Observation of Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed performance of portions of the following work orders (WOs):

- 406153-01 Lube, Inspect Containment Spray Pump
- 405586-01 Lube, Inspect Low Head Safety Injection Pump

b. Observations and Findings

All work had been properly approved by the operations department and was included on the plan of the day. The inspectors found that the work performed under these activities was professional and thorough. The work was performed with the work package present and in use. Accompanying documents such as procedures and supplemental work instructions were properly followed. Personnel were experienced, properly trained, and knowledgeable of their assignments. Tagout number 2-99-CS-008 for the containment spray pump inspection (WO 406153-01) was reviewed and found to be properly prepared and authorized. The tagged components were in the required positions and the tags were properly installed. The components were returned to their proper positions.

c. Conclusions

Maintenance activities which included lubrication and inspection of the containment spray and low head safety injection pumps were properly performed. Personnel conducting the activities were knowledgeable and followed work package instructions. A tagout on the containment spray system was properly implemented.

M8 Miscellaneous Maintenance Issues (92700)

M8.1 (Closed) LER 50-280/1998-006-00: Unisolable through wall leak for RCP thermowell. This LER dealt with the identification of a reactor coolant system leak on the Unit 1 B reactor coolant pump (RCP) lower radial bearing resistance temperature detector (RTD) thermowell. The unit was in cold shutdown at the time of discovery. The RTD is dry mounted in the thermowell, but after removal of the RTD cap the licensee noted that the thermowell was filled with water. The licensee has been unable to determine the cause of the leak, but Westinghouse has provided evidence that the failure mechanism may have been caused during manufacturing. The licensee took corrective actions to address this defect by installing a new design RTD that extended the pressure boundary to the RTD mechanical connection.

The inspectors discussed this issue with the system engineer and reviewed engineering transmittal 98-0058 that temporarily isolated the RTD opening with a seal welded plug. The inspectors concluded that the licensee completed stated corrective actions delineated in the LER. The inspectors also concluded that future licensee plans to inspect RCP thermowell caps are appropriate.

M8.2 (Closed) LER 50-280/1998-009-00: Nonisolable leak of reactor coolant pump seal injection line weld. This LER documented the licensee discovery of a through-wall leak in the seal injection line to the C RCP. Unit 1 was at full power operations at the time of discovery, but was subsequently placed in cold shutdown in accordance with Technical Specification requirements. The licensee attributed the cause of the leak to a lack of fusion or thermal fatigue at the toe of the weld coupled with vibration stress due to a loose rod hanger. Immediate corrective action included replacement of the seal injection

line and adjustment of the hanger. The licensee non-destructively tested corresponding welds for the A and B RCPs with no indications noted.

The inspectors reviewed stated licensee corrective actions and discussed with station personnel the applicability to the Unit 2 piping configurations. The inspectors also reviewed licensee plans to evaluate the need for additional hangers on the seal injection lines. The inspectors concluded that the licensee's planned and completed corrective actions were appropriate.

III. Engineering

E1 Conduct of Engineering

E1.1 Temporary Modifications (TMs)

a. Inspection Scope (37551)

The inspectors reviewed active TMs installed on Unit 1 and Unit 2.

b. Observations and Findings

The inspectors reviewed the six active TMs that were installed on Unit 1 and Unit 2 at the time of the inspection. The TMs will remain installed as long as the units remain in power operation. The inspectors reviewed the safety evaluation associated with TM S2-99-07, "2-RC-2591 Disc Removal." The safety evaluation adequately justified implementation of this TM.

c. Conclusions

A low number of temporary modifications (six) were installed on Units 1 and 2. The safety evaluation associated with Unit 2 temporary modification S2-99-07 for the removal of the reactor coolant loop isolation valve 2-RC-2591 disc adequately justified implementation of the modification.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls (71750)

On numerous occasions during the inspection period, the inspectors reviewed radiation protection (RP) practices including radiation control area entry and exit, survey results, and radiological area material conditions. No discrepancies were noted, and the inspectors determined that RP practices were proper.

The primary and secondary chemistry logs were reviewed to ensure plant chemistry was within the Technical Specification and procedural limits. No deficiencies were noted.

S1 Conduct of Security and Safeguards Activities

S1.1 General Comments (71750)

On numerous occasions during the inspection period, the inspectors performed walkdowns of the protected area perimeter to assess security and general barrier conditions. No deficiencies were noted and the inspectors concluded that security posts were properly manned and that the perimeter barrier's material condition was properly maintained.

S1.2 Alarm Stations and Communications

a. Inspection Scope (81700)

The inspectors evaluated Central Alarm Station (CAS) and Secondary Alarm Station (SAS) operations to determine if the licensee was effectively monitoring security operations as required by the Physical Security Plan (PSP). Additionally, the inspectors determined if communications were continuous and appropriate.

b. Observations and Findings

The review of security operational activities in the CAS and SAS and monitoring of security communications confirmed that the alarm stations were equipped in accordance with commitments contained in the PSP and were capable of communicating and effectively controlling the security force during routine and contingency operations. Alarm station operators were knowledgeable of their duties, appropriately trained, and capable of effective utilization of access control, intrusion detection, and communication equipment available in the alarm stations. The inspectors verified that the CAS and SAS were independent and diverse to the extent that no single act could remove the capability of the security force to call for assistance or otherwise respond to a threat. There were no operational activities observed in the alarm stations that would interfere with the execution of response to alarms or other contingencies. Intrusion detection equipment annunciated audibly and visually, as required. The alarm stations were continually manned by trained alarm station operators.

c. Conclusions

Based on alarm station operations in the areas of access control, intrusion detection, monitoring of alarms, and communication capabilities, the inspectors concluded that the Central and Secondary Alarm Stations' functions and communications systems were effective and met regulatory requirements specified in the PSP and implementing procedures.

S1.3 Protected Area Access Control

a. Inspection Scope (81700)

The inspectors reviewed the Access Control Program to determine if the licensee was properly removing favorably terminated individuals' unescorted access to protected and vital areas.

b. Observations and Findings

Chapter 3 of the PSP requires that an individual's access authorization be revoked when unescorted access is no longer required.

The inspectors conducted a review of the licensee's access control program by selecting records for 22 individuals who were employed by contract organizations and had recently been favorably terminated. These records were compared to the licensee's security computer database to verify the licensee was appropriately deactivating badges when individuals no longer had a need for access.

Of the records reviewed, the inspectors questioned the badging status of four individuals, since it appeared these individuals were terminated yet remained active in the security computer as well as in the hand geometry system. However, upon further review, the licensee demonstrated to the inspectors that those individuals in question were currently performing work at the licensee's North Anna Power Station and remained active in the Surry system on an as-needed basis during the time in question. All four individuals' badges were deactivated on July 28, 1999, when the licensee determined services were no longer required.

c. Conclusions

The licensee's access control program was effective in ensuring that favorably terminated employees' badges were deactivated in accordance with the PSP and implementing procedures.

S2 Status of Security Facilities and Equipment

S2.1 Testing and Maintenance

a. Inspection Scope (81700)

The inspectors determined if the licensee was appropriately testing and maintaining security equipment in operational order as required by the PSP and implementing procedures.

b. Observations and Findings

The licensee was required to operability test security related equipment once every seven days. The inspectors reviewed a sample of test records, which are electronically documented in the Security Shift Blotter, for the period of June through September 1999. Additionally, the inspectors reviewed post operational test records. All records reviewed indicated that testing was being performed in accordance with PSP and procedure commitments. Both open and closed maintenance work orders were reviewed and the inspectors determined that the licensee was promptly and appropriately repairing security related equipment.

The inspectors observed functional testing of one perimeter zone, which is completed on a quarterly basis. The licensee appropriately tested the zone in accordance with applicable procedures.

c. Conclusions

The licensee was testing and maintaining security related equipment as required by the PSP and implementing procedures. Security related equipment was being repaired in a timely manner.

S2.2 Compensatory Measures

a. Inspection Scope (81700)

The inspectors reviewed compensatory measures implemented by the licensee during testing and maintenance periods to determine if they met the PSP requirements.

b. Observations and Findings

The inspectors reviewed the Security Shift Blotter to determine if compensatory measures were implemented during periods when security equipment was not functional. Records reviewed indicated that appropriate compensatory measures were in place at these times. However, minor documentation errors in the Security Shift Blotter were noted by the inspectors which either referenced the wrong procedure or failed to identify fully what compensatory measures actually occurred. The licensee was reviewing those errors to determine corrective actions.

The inspectors observed appropriate compensatory measures in place during a functional test of a perimeter zone.

c. Conclusions

Compensatory measures observed and reviewed through documentation met the requirements outlined in the PSP.

S3 Security Safeguards Procedures and Documentation

S3.1 Security Program Plans

a. Inspection Scope (81700)

The inspectors reviewed a recently submitted revision to the licensee's PSP to determine if the changes incorporated were appropriately made under the provisions of 10 CFR 50.54(p).

b. Observations and Findings

Revision 5 to the PSP, dated March 17, 1999, allowed the licensee to discontinue a walkthrough inspection by operations and security prior to securing from refueling and major maintenance outages. The inspectors verified that this change did not pertain to those areas that were devitalized.

c. Conclusions

Revision 5 of the PSP was appropriately submitted under the provisions of 10 CFR 50.54(p).

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on November 18, 1999. The licensee acknowledged the findings presented.

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

PARTIAL LIST OF PERSONS CONTACTED

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
C. Luffman, Manager, Security
R. Savedge, Security Supervisor
T. Sowers, Manager, Station Safety & Licensing
B. Stanley, Supervisor, Licensing
J. Swientoniewski, Director, Nuclear Oversight
W. Thornton, Superintendent, Radiological Protection

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Process to Identify, Resolve, and Prevent Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 81700:	Physical Security Program for Power Reactors
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities

ITEMS OPENED AND CLOSED

Opened

50-280, 281/99007-01	NCV	Failure to report EDG automatic initiations, due to a loss of voltage on the 1H and 2J emergency busses, within 4 hours as required by 10CFR50.72 (Section O1.2)
50-280, 281/99007-02	URI	Review licensee's efforts at correcting PORV backup air system problems (Section O7.3)
50-281/99007-03	NCV	Failure to meet the requirements of TS 3.16.B, EDG inoperable greater than 7 days (Section O8.1)

50-281/99007-04	NCV	Failure to properly complete post maintenance testing prior to declaring the A LHSI pump operable (Section M1.1)

Closed

50-280, 281/99007-01	NCV	Failure to report an EDG automatic initiation, due to a loss of voltage on the 1H and 2J emergency busses, within 4 hours as required by 10CFR50.72 (Section O1.2)
50-281/99007-03	NCV	Failure to meet the requirements of TS 3.16.B, EDG inoperable greater than 7 days (Section O8.1)
50-281/99004-00	LER	EDG inoperable longer than allowed by TS due to governor compensation valve (Section O8.1)
50-280/98013-00, 01	LER	Turbine/Reactor trip on high steam generator level due to instrument failure (Section O8.2)
50-280/98014-00	LER	Manual reactor trip in response to main feedwater regulating valve failure (Section O8.3)
50-281/99003-00	LER	Auto reactor trip on low coolant flow due to loop stop valve failure (Section O8.4)
50-281/99007-04	NCV	Failure to properly complete post maintenance testing prior to declaring the A LHSI pump operable (Section M1.1)
50-280/1998-006-00	LER	Unisolable through wall leak for RCP thermowell (Section M8.1)
50-280/1998-009-00	LER	Nonisolable leak of reactor coolant pump seal injection line weld (Section M8.2)