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

Report Nos.: 50-280/91-26 and 50-281/91-26

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

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

Facility Name: Surry 1 and 2

Inspection Conducted: August 18 through September 28, 1991

Inspectors: A. Ruff For 10/28/91
M. W. Branch, Senior Resident Inspector Date Signed

A. Ruff For 10/28/91
J. W. York, Resident Inspector Date Signed

A. Ruff For 10/28/91
S. G. Tingen, Resident Inspector Date Signed

Approved by: 10/28/91
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, action on previous inspection findings, and emergency safeguards system walkdown. During the performance of this inspection, the resident inspectors conducted review of the licensee's backshift or weekend operations on August 25, 26, and 27, September 4, 5, 7, 12, 14, 15, and 22.

Results:

In the operations functional area, operations performance during shutdown, outage and startup was identified as a strength (paragraph 3.b). During the Unit 2 shutdown and startup, operators operated the unit in a safe and efficient manner and adhered to procedure requirements. During the brief Unit 2 outage, operators were attentive to their duties. Systems that required maintenance were properly isolated, returned to service, and tested. Communication between operations shift personnel was good and communication

between operations and other departments was also good. The brief outage was completed with minimal errors and on schedule. Operation performance was an improvement over that observed during the previous Unit 2 startup which was documented as a weakness in Inspection Report 50-280, 281/91-18.

During the inspection period, two reactor runbacks occurred in Unit 2. In the operations functional area, operator response to the runbacks was generally good. A weakness was identified involving operators overborating following the August 23 reactor runback (paragraph 3.a).

In the maintenance functional area, the troubleshooting activities associated with the Unit 2 A reactor trip breaker were thoroughly and efficiently accomplished. Management involvement was evident and the electricians accomplishing the troubleshooting appeared conscientious and knowledgeable (paragraph 5.a.).

In the maintenance functional area, several problems associated with implementation of the new post-maintenance test program were identified (paragraphs 5.a and 5.b).

In the maintenance functional area, the lack of detailed procedures for performing maintenance on certain air operated valves was identified as a weakness (paragraph 5.c).

In the operations functional area, configuration deficiencies discovered during a walkdown of the emergency service water pump house were identified as a weakness (paragraph 7).

An unresolved item was identified which involved administrative control of containment isolation valves (paragraph 3.d).

An unresolved item was identified which involved resolution of preservice and inservice inspection deviations (paragraph 6.b).

REPORT DETAILS

1. Persons Contacted

<u>Licensee Employees</u>

R. Allen, Supervisor, Shift Operations
*W. Benthall, Supervisor, Licensing
*R. Bilyeu, Licensing Engineer
*D. Christian, Assistant Station Manager
J. Downs, Superintendent of Outage and Planning
D. Erickson, Superintendent of Health Physics
*R. Gwaltney, Superintendent of Maintenance
*M. Kansler, Station Manager
T. Kendzia, Supervisor, Safety Engineering
*H. Kibler, Engineer, Testing
*J. McCarthy, Superintendent of Operations
*A. Price, Assistant Station Manager
*R. Saunders, Assistant Vice President, Nuclear Operations
*E. Smith, Site Quality Assurance Manager
*T. Sowers, Superintendent of Engineering

<u>NRC Personnel</u>

*M. Branch, Senior Resident Inspector
*P. Fredrickson, Section Chief, Division of Reactor Projects
*S. Tingen, Resident Inspector
*J. York, Resident Inspector

* Attended exit interview.

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

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

2. Plant Status

Unit 1 began the reporting period in power operation. On August 26, the unit experienced a turbine runback from 100 to 70 percent power when the A and B RSSTs were deenergized by the loss of switchyard bus 5. On August 27, the unit was returned to 100 percent power. Details of that transient are discussed in paragraph 3.f. Throughout the inspection period, power level was reduced numerous times to clean condenser waterboxes. The unit was at power at the end of the inspection period, day 283 of continuous operation.

Unit 2 began the reporting period at approximately 90 percent power due to fuel restrictions associated with the recovery of dropped control rod D4. On August 20, the unit was returned to 100 percent power. On August 23, the unit experienced a turbine runback to approximately 50 percent power when control rod D4 again dropped into the core. Details of that transient as well as the corrective actions associated with the attempts to recover rod D4 are discussed in paragraphs 3.a and 5.d. The unit operated at 60 percent power until September 7. The unit was shutdown on September 7, in order to troubleshoot rod D4. On September 15, the unit was restarted, and was at 100 percent power on September 18. The unit was at power at the end of the inspection period, day 14 of continuous operation. Throughout the inspection period, power level was reduced numerous times to clean condenser waterboxes.

3. Operational Safety Verification (71707 & 42700)

The inspectors conducted frequent visits to the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operations safety and compliance with TS and to maintain awareness of the overall operation of the facility. Instrumentation and ECCS lineups were periodically reviewed from control room indication to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. Deviation reports were reviewed to assure that potential safety concerns were properly addressed and reported.

a. Unit 2 Dropped Rod D4

On August 23, Unit 2 experienced another dropped rod, the same rod (D4) previously dropped on August 14. The trouble shooting and repair of this rod are discussed in paragraph 5.d of this report. The inspectors noted on the Tave recorder that after the rod dropped at 4:35 a.m., Tave dropped to 532 degrees F by 4:47 a.m. Technical Specification 3.1.E.4 states the reactor shall not be made critical when RCS temperature is below 522 degrees. Since Tave was lower than normal and close to the lowest allowed value, the inspectors questioned the reason for the low value. The licensee stated that overboration was the cause. The abnormal procedure used for a dropped rod, 0-AP-1.01, Control Rod Misalignment, dated September 30, 1991, requires in steps 4 and 19 that if the delta flux is not in the band that the operator should borate as necessary. This overboration event is identified as an operations weakness in that operator training and/or procedural guidance did not prevent its occurrence. The inspectors also noted that during the August 14 dropped rod event and subsequent turbine runback, operators also overborated the reactor. The August 14 event and overboration, during which Tave dropped to 551 degrees, was not as significant as the overboration that occurred on August 23.

b. Unit 2 Outage

On September 8, portions of the Unit 2 cooldown from 547 degrees F to 160 degrees F were monitored. The inspectors observed the licensee's performance from the control room, and reviewed procedures 2-OP-3.2, Unit Cooldown From HSD to 345 degrees F, dated August 6, 1991, and 2-OP-3.3, Unit Cooldown From 345 degrees F to HSD, dated January 1, 1990. The cooldown was satisfactorily accomplished. Operators conducted their duties in a safe and efficient manner and adhered to procedural requirements.

During the brief Unit 2 outage, operators were attentive to their duties. Systems that required maintenance were properly isolated, returned to service, and tested. Communication between operations shift personnel and other departments was good. The brief outage was completed with minimal errors and on schedule.

On September 15, portions of the Unit 2 reactor plant startup were monitored. The inspectors observed the licensee's performance from the control room and safeguards building, reviewed procedures 2-GOP-1.4, Unit Startup HSD to 2 Percent Reactor Power, dated September 12, 1991, and 2-PT-14.2, Main Steam Trip And Non-Return Valve Operability Verification, dated May 28, 1991. The startup was satisfactorily accomplished.

Operations performance during the above evolutions is identified as a strength.

c. AFW Header Temperature Indication

On September 24, the inspectors noted the temperature readings on the two Unit 2 AFW headers were approximately 100 degrees F. These readings appeared to be lower than previous temperature readings. Consequently, the inspectors questioned the accuracy of the thermocouples. Additionally, there were MR tags attached to the two meters indicating that a calibration was required. One of the MR tags also indicated that the probe was disconnected. The licensee's investigation of the inspectors observations included reading the piping with thermography instrumentation and evaluating the significance of the notes on the MR tags. The licensee determined that the readings were correct and that the note on the MR tags was intended to convey a need to periodically calibrate the meters. The licensee is still trying to determine the intent of the note that indicates the probe was disconnected. Due to insulation, the probe is not visible. The inspectors will continue to monitor the AFW piping temperature and will evaluate the licensee explanation associated with instrument accuracy and probe connection.

d. Unit 1 RCP B Shroud Cooler CC Water Leak

On August 28, the licensee discovered that a weld in the CC piping supply to the Unit 1 RCP B cubicle shroud cooler was cracked and leaking CC water into the containment. Operators isolated the leak by shutting the shroud cooler inlet and outlet isolation valves and also secured the shroud cooler fan. The licensee determined that repair of this leak was not practicable while the unit was operating and decided to delay repairs until a unit outage. Operating with the RCP B cubicle shroud cooler fan secured was not an operational problem. After discovery of the leak, the licensee determined that containment integrity was violated due to the failure of the membrane barrier and entered a six hour clock to hot shutdown in accordance with TS 3.0.1. After the leak was isolated, the six hour clock was exited. The inspectors reviewed the licensee's immediate corrective actions to restore containment integrity and consider that the corrective actions were adequate. The inspectors review of this event included section 5.2, Containment Isolation, of the FSAR. The FSAR provides the design basis for the containment isolation system. The inspectors noted that the CC inlet piping to shroud cooler contained a manual isolation valve outside containment (1-CC-218) and a check valve inside containment (1-CC-58). Section 5.2 of the FSAR stated that the manual valve was a containment isolation valve and was required to be administratively controlled. The inspectors noted that valve 1-CC-218 was not administratively controlled and questioned why it was not. This was discussed with the licensee, but was not resolved at the end of the inspection period. Pending additional information from the licensee, this issue is identified as URI 50-280/91-26-01, Administrative Control Of Containment Isolation Valves.

e. Licensee 10 CFR 50.72 Reports

(1) On September 3, at 8:42 a.m., the licensee made a report in accordance with 10 CFR 50.72 regarding a Virginia Power employee that was transferred offsite via the Surry Power Station ambulance. The employee had severe chest pains. No radiological contamination was involved.

(2) On September 7, at 10:54 a.m., the licensee made a report in accordance with 10 CFR 50.72 regarding a Virginia Power employee that was transferred offsite via the Surry Power Station ambulance. The employee had cut his thumb which resulted in severe bleeding. No radiological contamination was involved.

(3) On September 9, at 5:57 a.m., the licensee made a report in accordance with 10 CFR 50.72 regarding the failure of the Unit 2, "A" RTB to open when a manual trip signal was initiated. At the time of this event, the unit was in cold shutdown with all control rods inserted. RTBs "A" and "B" were closed to allow paralleling the rod drive MG set in preparation for control rod exercise testing. After paralleling the MG sets, a manual scram

signal was initiated. When the manual trip pushbutton was initially depressed, the "A" RTB failed to open and the "B" RTB opened as required. The same manual trip pushbutton was depressed a second time and the "A" RTB opened. The licensee's investigation of this event concluded that failure of the "A" RTB to initially open was because the operator did not fully depress the manual trip pushbutton. The inspectors monitored the maintenance associated with the failure of the "A" RTB to initially open and this is discussed in paragraph 5.a. The licensee subsequently retracted this 10CFR 50.72 report after they determined that the pushbutton would have properly worked if it had been fully depressed.

(4) On September 12, at 12:00 p.m., the licensee made a report in accordance with 10 CFR 50.72 regarding the inoperability of No. 2 EDG over the period of August 12 through 26. On August 26, No. 2 EDG automatically started due to an undervoltage on the Unit 2 H emergency bus. No. 2 EDG reached adequate speed for its output breaker to close and energized the H bus. However, the operator noted, after approximately ten minutes of operation, that the frequency was lower than expected. The frequency was approximately 53 hertz in lieu of the required 60 hertz. Operators took manual control of the No. 2 EDG and returned the frequency to normal. This event is discussed in the following paragraph.

f. Evaluation of August 26, Loss of Switch Yard Bus No. 5

Unit 1 experienced a turbine runback from 100 to 70 percent power due to a momentary loss of the IRPI semi-vital power supply as a result of deenergization of switchyard bus No. 5. Unit 2 remained at 60 percent power throughout the transient. Switchyard bus No. 5 supplies power to RSSTs A and B which in turn supply power to the 4160 volt emergency buses. The 1J and 2H emergency buses were deenergized and this resulted in the autostart and loading of the Nos. 2 and 3 EDGs. The EDGs remained running for approximately 17 hours while the failed 34.5 KV switchyard control power transformer was being replaced. During the transient, the control room operator noted that the No. 2 EDG speed was 800 RPM and not at the required nominal value of 900 RPM so he manually adjusted its speed. The failure of the No. 2 EDG to automatically operate at its nominal speed is discussed in detail later in this section.

During the above transient, while the EDGs were supplying vital bus power, the plant was being operated in an off-normal condition. The initial loss of the RSSTs resulted in the plant being in a six-hour to hot shutdown action clock per TS 3.0.2 due to a TS requirement on control room chillers. This clock was exited after a temporary jumper was installed and the failed switchyard transformer was electrically disconnected from bus 5. This allowed the control room chillers to be aligned for normal and emergency power. To electrically reconnect the new transformer and remove the temporary jumper it would be necessary to reenter the shutdown requirement of TS 3.0.2. Since voluntary entry into shutdown LCOs such as TS 3.0.2 has been discourged by the NRC, the licensee initiated communications with the NRC on this issue. During a telephone conversation between the licensee and the NRC, it was agreed that entry into TS 3.0.2 would be appropriate. When the new transformer was ready to be reconnected, the licensee entered the TS action, powered the emergency buses from the EDGs and deenergized the RSSTs. The licensee exited the TS action by restoring normal power to the buses and securing the EDGs.

The inspectors were onsite for a major portion of the event and monitored the licensee actions to replace the failed transformer as well as restoring normal electrical power to the station. With the exception of the problems with the No. 2 EDG discussed below, the inspectors did not identify any violation or deviations in this area.

The licensee evaluated the performance of the No. 2 EDG during the above transient and determined that the EDG did not meet all power requirements when operating at the reduced speed and frequency. The EDG is required to automatically achieve and maintain the proper frequency after receiving an automatic start signal. The licensee attributed the No. 2 EDG failure to an improperly adjusted governor speed control knob following surveillance testing that occurred on August 12. On August 12, a surveillance test was performed on No. 2 EDG in accordance with procedure 2-OP-EG-6.1, Number 2 Emergency Diesel Generator, dated September 13, 1991. At the end of the surveillance test, operators failed to properly adjust the governor speed control knob in accordance with the procedure. Adjustment of the governor speed control knob was required to ensure that the EDG would operate at the required speed and frequency upon receipt of an automatic start signal. Adjustment of the governor speed control knob was corrective action implemented in response to a recent failure of the No. 3 EDG to operate at the correct speed which was discussed in Inspection Report 50-280, 281/91-24.

The No. 2 EDG was secured at approximately 8:30 p.m. following the August 26, automatic start. The EDG shutdown procedure instructed the operator to manually reset the speed control knob after the EDG was secured. This action masks the ability to determine the previous manual speed setting. However, this action results in restoring the proper autostart setting for the EDG. The setting of the No. 2 EDG speed control knob was verified correct on September 5, when the No. 2 EDG was tested and satisfactorily operated at its required speed.

The failure of the No. 2 EDG was discussed during the September 17 enforcement conference. Since the failure of the No. 2 EDG to maintain rated speed and frequency, additional corrective actions have been implemented to ensure that EDGs reach and maintain the required speed after receipt of an automatic start signal. These corrective actions included adjustment of the governor limits switches, increased fast start surveillance frequency, and verifying that the governor gear match marks are properly aligned.

g. Unit 2 SW Piping Inspection

During the Unit 2 outage the licensee inspected the "D" 96 inch main condenser inlet header and both 48 inch SW supply headers to the Unit 2 containment RSHXs. The 96 inch header was drained, inspected and cleaned. Prior to cleaning the 96 inch header, the inspectors also inspected the header. Hydroid growth on the header walls was approximately three to four inches long. Based on this, the licensee concluded that hydroid growth was small. Throughout the summer, main condenser water boxes required frequent cleaning. One of the major sources of water box fouling was hydroids. The licensee is currently evaluating the source of the hydroids to the water boxes. Divers were utilized to inspect the 48 inch SW headers. Results of this inspection were that hydroid growth was minimal. The licensee considers that the program implemented to prevent hydroid growth in the 48 inch headers has been successful in minimizing the hydroid growth in these headers.

Within the areas inspected, no violations were identified.

5. Maintenance Inspections (62703 & 42700)

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

The following maintenance activities were reviewed:

a. Repair of Unit 2 Manual Trip Pushbutton

On September 9, the inspectors witnessed troubleshooting activities associated with manual trip pushbutton failure to open Unit 2's "A" RTB. This event was previously discussed in paragraph 3.e(3). Troubleshooting was accomplished in accordance with WO 3800115819. A special SNSOC meeting was convened to discuss and approve the troubleshooting instructions for this WO. The troubleshooting centered around checking the "A" RTB and its manual trip pushbutton for proper operation. Testing of the RTB's shunt trip and under-voltage coils proved that the breaker operated satisfactorily. Testing of the manual trip pushbutton revealed that if the button was only partially depressed, the "B" RTB received an open signal and the "A" RTB would not receive an open signal. When the pushbutton was fully depressed, the "A" RTB also received an open signal and opened. Operation of the pushbutton was discussed with Westinghouse who stated that the pushbutton was operating correctly. Attached to the back of the manual trip pushbutton is a stack of five contact blocks. Each contact block contains two sets of contacts, one set is normally open and the other set normally shut. When the manual trip pushbutton is depressed, the first contact block deenergizes the "B" RTB undervoltage coil and energizes the "B" RTB shunt trip coil. The third contact block accomplishes the same function for the A RTB. In order to enhance the operation of the pushbutton, the first and third contact blocks were replaced. After replacement of the two contact blocks, the "A" and "B" RTBs opened when the manual trip pushbutton was partially depressed.

The inspectors reviewed the completed work package for troubleshooting the failure of the "A" RTB to open. With the exception of post maintenance testing, no discrepancies were noted. The inspectors considered that the troubleshooting activities were thorough and efficiently accomplished. Management involvement was evident and the electricians accomplishing the troubleshooting were conscientious and knowledgeable.

The PMT for this maintenance required that 2-PT-8.2, Reactor Protection Logic, be performed. The inspectors reviewed the performance copy of 2-PT-8.2 and considered that the PMT did not recognize the proper retest. However, the manual pushbutton was properly retested because the electrician accomplishing this maintenance went beyond the PMT scope. The maintenance required the removal and installation of all five of the contact blocks attached to the right hand manual trip pushbutton. The inspectors considered that improper assembly of the contact blocks could result in improper operation of the pushbutton, and that a correct PMT would have required that all ten contacts enclosed in the five contact blocks be tested to ensure that they properly repositioned when the pushbutton was depressed. 2-PT-8.2 did not accomplish this. The inspectors discussed testing of the pushbutton with the electricians who performed the maintenance. The electricians stated that, although not documented, the contacts were tested after installation of the pushbutton. The failure to specify a correct PMT for this maintenance was identified as a weakness.

b. Repairs to Valve 2-RC-63

Valve 2-RC-63 is a manually operated three inch diameter gate valve in the B loop RTD bypass line. There was a 10 to 12 drops per minute body-to-bonnet leak in this valve identified during the Unit 2 forced outage which commenced on September 7. Since there were no other valves downstream to isolate this valve, the licensee utilized two redundant freeze seals approximately ten feet apart. Upstream isolation of the valve was satisfied by closing valves 2-RC-55 and 2-RC-56.

The inspectors reviewed the 10 CFR 50.59 safety analysis (91-211) and noted that the licensee had considered actions that would be taken if the freeze seal was lost. At 50 psig RCS pressure, a leak of 1140 gpm would be experienced from the 3 inch diameter pipe. The low head SI pump can deliver approximately 3200 gpm and this would be sufficient to prevent uncovering the core. In addition, if the seal were lost, the loop stop valves would be utilized to isolate this loop.

WO 3800115884 was used to remove the valve bonnet and internals, to cap the valve packing drain line, and to install a blind flange. Engineering analysis determined that it was not necessary to have this isolation valve in the system. WO 3800115883 was used to install the freeze seals. Mechanical maintenance procedure no. 0-MCM-0401-01, Valves and Traps In General, dated August 1, 1991, was used for the valve repair. Corrective mechanical maintenance procedure MMP-C-FS-260, Freeze Sealing-Liquid Nitrogen Method-Single Freeze, dated July 9, 1991, was used twice to install the double freeze seal. The freeze seal procedure did require that temperature detection devices be used to warn against the possibility for thawing the freeze seal (as recommended in IN-91-41). During the same type of maintenance repair on valve 2-RC-95 (ref. Inspection Report 50-280, 281/91-14) there was some concern about and a weakness identified on operations involvement with authorization to melt the freeze seals. The inspectors noted improvement in this activity, in that the procedure had been changed and the shift supervisor is aware when this operation begins and ends.

On September 14, deviation report S-91-1404 identified the fact that post maintenance testing did not require the performance of periodic test PT-53.1A, ASME System Pressure Tests, dated October 3, 1989, after performance of the previously described valve maintenance. After opening and reclosing of a system, the ASME Code, Section XI, requires that a Class 1 system have a leakage test conducted after pressurization to normal operating pressure. Operations detected this deviation and the periodic test was performed before returning this system to service. The failure of the PMT program to properly identify the correct post maintenance test requirements is identified as a weakness similar to the one identified in paragraph 5.a. Other PMT problems were also identified in Inspection Reports 280,281/91-21 and 24, associated with an ESW pump and No. 3 EDG. The PMT problem associated with the EDG resulted in escalated enforcement action. The inspectors concluded that PMT implementation problems are hindering the effectiveness of the new PMT program and that more management attention is needed to properly implement this program.

c. Past Maintenance on Valve TV-DA-200A

During the reactor trip/safety injection event that occurred on August 2, (ref. Inspection Report 50-280, 281/91-21) SI Phase I isolation occurred which requires certain valves to close for containment isolation. Valve TV-DA-200A, which is the containment sump trip isolation valve, failed to fully close. The licensee performed a Cause Determination Evaluation (licensee report no. 114373). A memorandum from the system engineer dated August 5, 1991, stated that disassembly of this valve after the trip/safety injection revealed that there were more springs installed in the valve seats than were recommended on the drawing (40 installed versus 20 required on the drawing). The memo also stated that these excess springs have the possibility to cause binding in the valve operation and to increase the stroke time.

The repair on this valve was performed in October 1988, using a generic procedure. The CFE report stated that the usage of a detailed procedure for this valve would have prevented this error of installing too many springs. There are a total of four of these valves, two in each unit. The other three valves have been evaluated through data from perodic tests, stroke times, etc., and are functioning properly.

A previous station deviation, S-91-0515 dated April 17, 1991, reported that the cage spacer was left out on pressurizer spray valve no. 2-RC-PCV-2455A during a maintenance repair. The corrective action plan for this deviation stated that the lack of a detailed procedure was a contributor to leaving the spacer out of the valve during reassembly. It was pointed out in this response, that the lack of specific maintenance repair procedures for some of the air operated valve is a generic problem.

The inspectors reviewed a request for new procedures from maintenance engineering to the procedure group dated August 23, 1991. This request gave a list of the valves and the priority for developing the procedures.

This lack of adequately detailed procedures for performing maintenance on certain air operated valves is identified as a weakness.

d. Repair of Dropped Control Rod D4

During the last inspection period, the inspectors reported the dropping of the D4 control rod in Unit 2 on August 14 (ref. Inspection Report 50-280, 281/91-21). The licensee replaced the fuses, took electrical measurements, visually examined the circuit, and extracted the dropped rod. No apparent root cause for dropping the rod could be determined. On August 23, at 4:35 a.m. the same rod was dropped again.

The licensee performed additional tests such as meggering the cables, visually examining cables in the containment and in the rod control cabinet, and installing a separate DC power supply for testing the circuit at a higher amperage and voltage. None of these tests identified the problem.

The licensee, in conjunction with Westinghouse, decided to install a temporary modification in the rod control circuitry. This modification would allow the D4 rod to be removed from the core and held by both the moveable and the stationary gripper coils. Both of these coils had their own separate circuits and were connected to the DC hold bus. This would allow the rod to be tripped but not moved. When an attempt was made to lift the rod out of the core the moveable gripper coil shorted out and the licensee decided to shutdown to make the necessary repairs.

WO 3800115065 and corrective electrical maintenance procedure EMP-C-EPCR-39, Control Rod Position Detector Assembly and the Operating Stack Assembly Removal and Repair, dated December 18, 1988, were used to make the repairs. The licensee decided to replace all three coils and the control rod drive electrical cable. Electrical testing showed only the moveable coil was defective. In addition, some cracking was observed in this coils insulation. A cold rod drop test showed that the D4 rod moved and tripped successfully. No discrepancies were identified by the inspectors.

Within the areas inspected, no violations were identified.

6. Surveillance Inspections (61726, 42700)

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

- Test prerequisites were met.
- Tests were performed in accordance with approved procedures.
- Test procedures appeared to perform their intended function.
- Adequate coordination existed among personnel involved in the test.
- Test data was properly collected and recorded.

The following surveillance activities were either reviewed or observed:

a. Hot Rod Drop Testing

On September 11, the inspectors witnessed the performance of periodic test NPT-RX-007, Hot Rod Drops, dated September 11, 1991, performed only on rod D4 which was repaired during the outage. The inspectors observed testing from the control room. The rod was withdrawn 225 steps and then dropped. The cycle allowed for this test was a maximum of 2.4 seconds and the actual time measured by the reactor engineer was 1.26 seconds. No discrepancies were identified.

b. Inservice Testing of Welds

Inspection Report 50-280,281/91-21, discussed the potential problem that existed at Surry concerning the inclusion of longitudinal welds in the ISI program. The licensee issued a memorandum outlining the approach to be used for resolution of this potential problem. It was also stated that a deviation would be written and dispositioned for any variations from the ISI program.

The licensee's initial ISI program committed to the 1974 ASME Code through 1975 Summer Addendum for inspection and testing of equipment. Table IWC-2520, Examination Categories, Section C-G, requires that longitudinal weld joints in pipe fittings (i.e., in tees, elbows, recesses) be included in the ISI program unless approval is given to exclude these welds. This code does not require longitudinal welds in piping to be inspected.

The licensee's evaluation of the program resulted in two station deviations. Station deviation S-91-1183 stated that the possibility existed that main steam fittings having longitudinal welds may not have been included in the initial ISI program. There were no weld maps (Grinnell drawings) for the main steam fittings and a records search of inspections performed during the first ISI interval indicated that no longitudinal welds were examined. The licensee stated that this did not constitute a Code violation because there are five types of welds in this category (i.e., circumferential butt welds, longitudinal weld joints in pipe fittings, etc.) and 50 percent of the total number of the five types of welds are to be inspected during the life of the plant. The corrective action associated with this deviation also stated that the Code is not clear that the overall sample be prorated to the number of each type of weld nor is it clear that each type of weld has to be considered in the representative sample for a specific interval. The action plan for this deviation requires that one main steam weld in Unit 1 (located on the longitudinal weld of a fitting) and two welds in the same system on Unit 2 be examined. This is the same population that would have been examined had the system's longitudinal welds been in the first ISI interval. The two Unit 2 MS system welds examined during a recent forced outage were found to be acceptable. This leaves only the one Unit 1 MS system weld to be inspected during a shutdown outage.

The second station deviation (S-91-1197) was written when the records review revealed that preservice examinations were not performed on 10 inch diameter recirculation spray system piping (for both units) that was replaced by DCP 87-22 and DCP 87-23. These welds had been inspected, but the preservice base line inspection (surface inspection) required by ASME Section XI was not performed.

Pending further NRC technical review of these deviations, this is identified as Unresolved Item 280,281/91-26-02, Resolution of Preservice and ISI Deviations.

Within the areas inspected, no violations were identified.

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

(Closed) Violation 280,281/89-34-02, Failure to Implement Adequate Control Measures To Prevent The Use of Incorrect Materials Or Parts. The issue involved the use of incorrect gasket material during maintenance associated with the installation of Units 1 and 2 pressurizer safety valves and the assembly of SI check valves 2-SI-79 and 2-SI-91. The licensee responded to this violation in a letter dated February 6, 1990. In the letter the licensee stated that corrective action had been implemented which established an Engineering Parts Validation Program whereby engineering personnel are required to ensure that correct parts/components (with regard to technical data and materials) are installed in the respective system per design and licensing requirements. During a previous inspection period, the inspectors were unable to close this violation because the original Engineering Parts Validation Program had been cancelled. The licensee has replaced the Engineering Parts Validation Program with other methods of material control. The licensee has implemented a comprehensive material procurement program which is described in Station Administrative Procedure VPAP-0702, Identification and Control of Material, Parts, and Components, dated September 17, 1990. VPAP-2002, Work Requests and Work Orders, dated July 1, 1990 was revised to require craft personnel to verify correct gasket material by measurement or inspection prior to installation. The inspectors reviewed VPAP-0702 and VPAP-2002 and consider that these corrective actions were satisfactorily implemented, therefore this item is closed.

Within the areas inspected, no violations were identified.

8. ESF System Walkdown (71710)

The inspectors walked down the ESW system. Drawings 11448-FM-071A and 071E were utilized for this walkdown. Additionally, procedures OP-49.2A, Emergency Service Water System Valve Alignment, dated February 25, 1991; 1-PT-25.3A, Emergency Service Water Pump 1-SW-P-1A, dated September 12, 1991; OP-49.2, Diesel Driven Emergency Service Water Pump Operation, dated February 25, 1991, were used to accomplish this walkdown. The following discrepancies were identified during the walkdown:

- The instrumentation valves associated with flow instruments 1-SW-FE-121A, B and C were not aligned in accordance with OP-49.2 or 1-PT-25.3A restoration steps. These procedures require that the instrument drain valves be opened and remain open when the ESW system is not in use. The drain valves were shut with pipe caps installed over the drain lines. The ESW system was not operating when the walkdown was performed.

- The inspectors noted that the instrument root valves associated with 1-SW-FE-121A were shut and the same valves associated with 1-SW-FE-121B and C were open. OP-49.2 and 1-PT-25.3A provided conflicting restoration instructions for aligning instrumentation valves associated with flow instruments 1-SW-FE-121A,B and C. After discussing this issue with the system engineer, the inspectors concluded that 1-PT-25.3A was correct. OP-49.2 specified that the instrument root isolation valves be shut while 1-PT-25.3A specified that the instrument root isolation valves be opened. The system engineer stated that it was desirable to leave the instrument root valves and instrument drain valves open so the lines would be drained for freeze protection.

- System drawings illustrated that flow instruments 1-SW-FE-121A, B and C existed, but did not illustrate the instrument valves associated with the flow instrumentation. This was discussed with engineering who stated the these flow instruments were recently installed as a design change and that, through the design change process, these drawings will be revised to show that these valves exist.

- Valve lineup procedure OP-49.2A did not provide instructions for aligning the instrument valves associated with flow instruments 1-SW-FE-121A, B and C. However, the procedures that operated and tested the ESW system, OP-49.2 and 1-PT-25.3, did provide instructions for aligning these valves.

- The inspectors noted several components that were not labeled. Air dampers 1-VS-DMP-102,103,104,105, and 106, vent valves for pressure instruments 1-SW-PI-107A, B and C, duplex strainer 1-SW-STR-4A, and the instrument valves associated with 1-SW-FE-121A, B and C were not labeled.

- The inspector noted that the system drawings and system valve lineup provided conflicting instructions for positioning valves 1-SW-291, 555, 554, 560, 561, 566, and 567. After discussions with engineering, it was concluded that the valve positions specified in the valve lineup procedure was correct. The valves were in the positions specified by the valve lineup procedure when the inspectors walked down the system. The inspectors were informed that station policy did not require that system drawings show correct valve position. Procedures and valve lineups were utilized to align systems not station drawings.

- The system drawing did not illustrate the level indication system for the ESW diesel fuel oil storage tank and did not illustrate the vent valves located upstream of pressure gages 1-SW-PI-107A, B and C.

The inspectors consider housekeeping in the ESW pump house to be good. The deficiencies noted were not significant but indicated that a weakness existed in the area of configuration control of the ESW system. In previous inspections periods, the inspectors have walked down other ESF system and did not identify similar deficiencies. However, the inspectors have noted that instrument valves throughout the station are not always numbered or identified. The licensee promptly initiated actions to correct these deficiencies after identification by the NRC.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and results were summarized on October 2, 1991 with those individuals identified by an asterisk in paragraph 1. The following summary of inspection activity was discussed by the inspectors during this exit.

Item Number	Status	Description and Reference
URI 50-280/91-26-01	Open	Administrative Control Of Containment Isolation Valves, paragraph 3.d.
URI 50-280,281/91-26-02	Open	Resolution of Preservice and ISI Deviations, paragraph 6.b.
VIO 50-280,281/89-34-02	Closed	Failure to Implement Adequate Control Measures To Prevent The Use of Incorrect Materials Or Parts, paragraph 7.

The licensee acknowledged the inspection conclusions with no dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

10. Index of Acronyms and Initialisms

AFW - AUXILIARY FEEDWATER
ASME - AMERICAN SOCIETY OF MECHANICAL ENGINEERS
CC - COMPONENT COOLING
CFE - COMPONENT FAILURE EVALUATION
CFR - CODE OF FEDERAL REGULATIONS
DC - DIRECT CURRENT
DCP - DESIGN CHANGE PACKAGE
ECCS - EMERGENCY CORE COOLING SYSTEM
EDG - EMERGENCY DIESEL GENERATOR
ESF - ENGINEERED SAFETY FEATURE
ESW - EMERGENCY SERVICE WATER
F - FAHRENHEIT
FSAR - FINAL SAFETY ANALYSIS REPORT
GPM - GALLONS PER MINUTE
HSD - HOT SHUTDOWN
IN - INFORMATION NOTICE
IRPI - INDIVIDUAL ROD POSITION INDICATION
ISI - INSERVICE INSPECTION

KV	-	KILOVOLT
LCO	-	LIMITING CONDITION OF OPERATION
MG	-	MOTOR GENERATOR
MR	-	MAINTENANCE REQUEST
NA	-	NOT APPLICABLE
NCV	-	NON-CITED VIOLATION
NRC	-	NUCLEAR REGULATORY COMMISSION
PMT	-	POST MAINTENANCE TEST
PSIG	-	POUNDS PER SQUARE INCH GAUGE
RCP	-	REACTOR COOLANT PUMP
RCS	-	REACTOR COOLANT SYSTEM
RPM	-	REVOLUTIONS PER MINUTE
RSHX	-	RESIDUAL HEAT EXCHANGER
RSST	-	RESERVE STATION SERVICE TRANSFORMER
RTB	-	REACTOR TRIP BREAKER
RTD	-	RESISTANCE TEMPERATURE DEVICE
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR AND SAFETY OPERATING COMMITTEE
TS	-	TECHNICAL SPECIFICATIONS
URI	-	UNRESOLVED ITEM
VPAP	-	VIRGINIA POWER ADMINISTRATIVE PROCEDURES
WO	-	WORK ORDER