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

Report Nos.: 50-280/95-17 and 50-281/95-17

Licensee: Virginia Electric and Power Company
Innsbrook Technical Center
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: September 3 through October 14, 1995

Lead Inspector: For 11/2/95
M. W. Branch, Senior Resident Inspector   Date Signed

Other Inspectors:

D. M. Kern, Resident Inspector
W. K. Poertner, Resident Inspector
L. R. Moore, Region II
L. W. Garner, Region II, Project Engineer

Approved by: 11/02/95
G. A. Belisle, Chief   Date Signed
Reactor Projects Branch 5
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance and surveillance inspections, engineering review, plant support, balance of plant review, deviation report review, and action on previous inspection items. Inspections of backshift and weekend activities were conducted.

Results:

Plant Operations

Control room operators exhibited good command and control and properly implemented abnormal procedures during the September 29 power loss to the 1H and 2J emergency buses (paragraph 3.3).

Operations' identification and pursuit of resolution of a suspected Reactor Coolant System leak associated with pressurizer level tap piping, demonstrated a good questioning attitude (paragraph 4.4).

Maintenance

Station blackout testing evolutions were adequately controlled. Test performance and resolution of a test problem demonstrated good communications between operations, engineering, and maintenance organizations (paragraph 4.2).

Maintenance personnel properly implemented several positive initiatives to improve Unit 1 Rod Control System reliability. Root Cause Evaluation (RCE) 95-08 was thorough and established a comprehensive set of corrective actions (paragraph 4.3).

The RCE associated with the September 14, Turbine Building flooding event, performed by the line organization, represented a commitment to identify and correct conditions which represented high risk for core damage (paragraph 7).

Engineering

The deficiencies discovered during motor operated valve coefficient of friction testing were properly addressed (paragraph 4.1).

The 1A and 2A station batteries experienced repeated low cell voltages and electrolyte stratification during the first half of 1995. A subsequent RCE was comprehensive. The 1A station battery was replaced during the Unit 1 refueling outage. Continuing licensee actions to address battery degradation were appropriate (paragraph 6).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*W. Benthall, Supervisor, Licensing
*H. Blake, Jr., Superintendent of Nuclear Site Services
*R. Blount, Superintendent of Maintenance
*D. Christian, Station Manager
J. Costello, Station Coordinator, Emergency Preparedness
*D. Erickson, Superintendent of Radiation Protection
*B. Garber, Licensing
*R. Garner, Outage and Planning
B. Hayes, Supervisor, Quality Assurance
D. Hayes, Supervisor of Administrative Services
*C. Luffman, Superintendent, Security
*R. Lynch, Administrative Services
J. McCarthy, Assistant Station Manager, Operations and Maintenance
*H. Miller, Quality Assurance
*S. Sarver, Superintendent of Operations
R. Saunders, Vice President, Nuclear Operations
*B. Shriver, Assistant Station Manager, Nuclear Safety and Licensing
K. Sloane, Superintendent of Outage and Planning
E. Smith, Site Quality Assurance Manager
*T. Sowers, Superintendent of Engineering
*J. Swientoniewski, Supervisor, Station Nuclear Safety

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

NRC Personnel

*M. Branch, Senior Resident Inspector
D. Kern, Resident Inspector
*K. Poertner, Resident Inspector
*L. Garner, Project Engineer, Region II

*Attended Exit Interview

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

2. Plant Status

Unit 1 was shutdown on September 8 for a scheduled 37 day RFO. The unit remained shutdown for the rest of the inspection period.

Unit 2 operated at power for the entire period. The C RCP seal leakoff flow dropped below the recommended value during the inspection period.

AP 9.00, RCP Abnormal Conditions, revision 6, was entered and seal flow was closely monitored during the remainder of the inspection period.

3. Operational Safety Verification (71707)

The inspectors conducted frequent tours of the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operational safety and compliance with TSs and to maintain overall facility operational awareness. Instrumentation and ECCS lineups were periodically reviewed from control room indications 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.

3.1 RHR Pump Throughwall Leak

On September 9, at approximately 10:30 p.m., an ISI inspection identified a throughwall leak in the Unit 1 A RHR pump casing. An evaluation determined that the leak was approximately one drop per minute and was located on the suction side of the pump casing. At the time of discovery, the A RHR pump was inservice and the RCS was solid and pressurized to 300 psig. The pump casing was inspected by an NDE engineer and an ultrasonic examination was attempted but was unsuccessful due to the leak location. A visual examination indicated that the defect was a casting flaw, probably due to porosity. The pump was declared inoperable at 3:30 a.m. on September 10, based on ASME Section XI criteria. However, the pump was left in service due to operator concerns with swapping RHR pumps with the RCS solid. These concerns were addressed and the pump was subsequently secured at 9:35 a.m., after the B RHR pump was started for decay heat removal.

The A RHR pump was isolated and the piping drained to determine if adequate isolation could be achieved to perform repairs. The licensee determined that the leakage past the pump isolation valves would not support repairing the pump with the RHR system pressurized. The licensee initially requested enforcement discretion from the NRC to allow entry into the refueling mode of operation with only one operable RHR pump. TS requires that two RHR pumps be operable with the reactor head detensioned and level in the transfer canal less than 23 feet. The NRC determined that the circumstances did not meet the criteria for enforcement discretion. Based on discussions with NRC, the licensee submitted a relief request from ASME Section XI requirements for flaw evaluation requirements. The relief request was based on an analysis that determined that the structural integrity of the pump would be maintained under design basis loadings. The relief request was approved by the NRC on September 12, and the licensee continued with refueling outage activities to commence core offload. Once the core was offloaded, repair of the A RHR pump was initiated. Pump repair was completed prior to core onload.

3.2 Unit 1 Loss of Inventory Event

On September 14, 1995, while shutdown for refueling, the Unit 1 reactor vessel water level standpipe indication experienced an unexpected drop from approximately 18 feet to 13.3 feet. The cause of the event was due to the isolation of the reactor head vent with a nitrogen bubble trapped in the head. As pressure was relieved from the top of the standpipe due to depressurizing the PRT, indicated standpipe level increased. Control room operators increased the letdown rate in order to maintain standpipe level stable at 18 feet. The letdown continued for approximately three and a half hours until the bubble in the reactor head expanded and reached equilibrium. Approximately eleven hours later, reactor vessel head detentioning allowed a vent path for the bubble. This caused the standpipe level to drop to 13.3 feet, the actual reactor vessel water level. RHR cooling was not lost during the event. Details of this event are documented in NRC IR 50-280, 281/95-20.

3.3 Loss of Power to Two Emergency Buses

On September 29 at 8:01 a.m., power was lost to the 1H and the 2J emergency buses. At the time of the event, Unit 1 was in a refueling outage with the core offloaded to the spent fuel pool and Unit 2 was operating at 100 percent power. When power was lost, the #1 EDG and #3 EDG automatically started on bus undervoltage conditions and reenergized the 1H and 2J emergency buses, respectively, as designed. During the event, Unit 2 remained stable at 100 percent power and the Spent Fuel Pool Cooling System remained in service to remove decay heat.

The 1H and 2J emergency bus deenergized due to breaker 15C1 opening. An operator opened the fuse drawer for the F transfer bus potential transformer which caused a simulated undervoltage condition on the F transfer bus and a trip signal to breaker 15C1. When breaker 15C1 tripped, power was lost to the F transfer bus and the 1H and 2J emergency buses which were being supplied from this bus. Offsite power was restored to the F transfer bus at 12:57 p.m. The 2J emergency bus was paralleled with the F transfer bus and the #3 EDG was secured at 2:11 p.m. The 1H emergency bus was paralleled with the F transfer bus and the #1 EDG was secured at 4:04 p.m.; thereby, restoring the electrical distribution system to the configuration that existed prior to the event.

The inspectors were in the control room when the momentary loss of power occurred. The inspectors independently verified plant status and monitored operator actions immediately following the loss of power to the emergency buses and the actions taken to restore offsite power. The inspectors verified proper operation of the EDGs subsequent to their automatic loading onto the 1H and 2J emergency buses and verified that Electrical Distribution System TS requirements were met. The inspectors determined that the operators in the control room exhibited good command and control and properly implemented the abnormal procedures during the event. The licensee will submit an LER in accordance with 10 CFR 50.73 describing this event. The inspectors will review the licensee's root cause and corrective actions when the LER is completed.

3.4 Component Cooling Heat Exchanger Fouling

On October 6 at 8:20 p.m., the RM on the C CCHx alarmed in alert. Subsequent investigation by Operations revealed nothing abnormal and a sample of the SW side of the C CCHx did not indicate any increase in radioactivity. The Hx was performance tested to determine operability per procedure 1-OSP-SW-004, Measurement of Macro Fouling Blockage of CCHx, revision 4. This test determined that the C CCHx was inoperable due to reduced SW flow. The Hx was declared inoperable at 10:50 p.m., and removed from service for cleaning. Prior to declaring the C CCHx inoperable, the A CCHx RM also alarmed in alert at approximately 9:50 p.m. During this same time frame the operators determined that CCHx outlet temperatures were increasing along with Unit 2 containment temperature.

The C CCHx was cleaned and returned to service at 12:55 a.m. on October 7, at which time CC temperatures stabilized. Subsequent testing of the A, B, and D CCHxs determined that they were also inoperable due to reduced SW flows. The A CCHx was cleaned and returned to service at 5:44 a.m. on October 7. The B and D CCHxs were also cleaned and returned to service on October 7.

Based on the CCHx test results, the licensee determined that all four CCHxs were inoperable from 10:50 p.m. on October 6 until 12:55 a.m. on October 7, when the C CCHx was cleaned and returned to service. TS 3.0.1, which required a unit shutdown within six hours, was entered. After the C CCHx was made operable at 12:55 a.m. on October 7, TS 3.0.1 was exited before a unit shutdown was initiated.

Initial investigation by the licensee determined that the SW supply had been swapped from the D CW line to the B CW line at 11:51 a.m. on the day shift and that the B condenser waterbox had been returned to service at 3:32 p.m. The licensee initiated a root cause evaluation to determine the cause of the flow blockage and develop corrective actions to prevent recurrence. The licensee plans to issue an LER describing this event. The root cause had not been completed at the end of the inspection period. The inspectors will review this item further when the licensee's root cause is issued.

3.5 Review of Corrective Actions for PZR Insurge and Outsurge Controls

During the February 4, 1995, Unit 2 cooldown, the licensee experienced difficulty in controlling thermal transients on the PZR. At the time of the event, there was a bubble in the PZR and degas evolutions were in progress. Degassing with a bubble required the RO to balance charging and letdown flows to maintain a relatively constant level in the PZR. Difficulty in balancing these flows was determined to be the cause of exceeding TS limits for PZR heatup rate. This event resulted in a TS violation and is described in detail in IR 50-280, 281/95-06.

As corrective action for the TS violation, the licensee consulted with an industry group that was working on improving methods for controlling routine startup and shutdown evolutions. Prior to the September 8 Unit 1 RFO shutdown, the licensee determined that a chemical degas of the RCS would be used. This process allowed the PZR to be taken solid sooner in the shutdown/cooldown evolution which provided more schedular flexibility and at the same time reducing PZR thermal transients. The inspectors reviewed procedure 1-OP-RC-012, RCS Degas Operations, revision 0, which implemented the chemical degas process. The procedure contained appropriate precautions and limitations, as well as, detailed instructions. During the September 1995 Unit 1 RFO shutdown/cooldown, this method was successfully implemented and no unacceptable PZR thermal transients occurred.

3.6 Containment ESF Sump Inspection

Prior to closeout of the Unit 1 containment at the end of the RFO, the inspectors toured the containment building. The inspectors checked the containment ESF sump for foreign material. The grating was in place and no foreign material was noted. Additionally, the inspectors noted that the condition of the fibrous filters used in the Iodine Removal System were acceptable. The inspectors also verified, prior to unit startup, that the required water seal to prevent containment sump valve thermal pressure locking was present in the containment ESF sump. This verification was based on control room containment ESF sump level instrument indication.

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

4. Maintenance and Surveillance Inspections (62703, 61726, 62705)

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

4.1 MOV COF Testing

The inspectors reviewed the MOV COF Testing Results Report, dated September 27, 1995. The report was a final summary of the COF testing performed on 17 Unit 1 MOVs during this outage. The testing completed the planned COF testing and verification that a COF value of 0.15 was appropriate for use in MOV analyses. The inspectors confirmed that as-found test results supported the conclusion that MOV lubrication problems experienced at North Anna had not occurred at Surry.

Two valves, 1-FW-MOV-160B and 1-SI-MOV-1860A, with as-found COF values of 0.165 and 0.190, respectively, were considered as test failures. Actuator disassembly and inspection revealed that 1-FW-MOV-160B had approximately 10% greater stem nut to stem thread engagement than normal. In addition, the thread machining operation during stem manufacturing had resulted in some stem thread roughness. The actuator was cleaned, lubricated and reassembled. The stem threads were also dressed. A similar examination for 1-SI-MOV-1860A revealed that the stem nut to stem thread engagement was approximately 40% greater than expected and the presence of several small stem thread burrs and dents. The stem was dressed. Since the valve actuator had a relatively small thrust margin above that required for valve operation, the licensee decided to replace the SMB-000 actuator with a SMB-00 actuator. A similar modification was performed to 1-SI-MOV-1860B which had the expected stem nut to stem thread engagement and a 0.105 as-found COF test value. Subsequent testing verified that the COF values for 1-FW-MOV-160B and 1-SI-MOV-1860A and B were less than 0.15. The inspectors concluded that the deficiencies discovered during COF testing were properly addressed.

During data review, the inspectors noted that the valves tested did not represent all possible combinations of stem sizes and valve manufacturers. This observation was discussed with cognizant regional personnel who indicated that COF testing for each stem size by valve manufacturer was not necessary. The sample size and the appropriateness of the valves chosen will be further reviewed as part of the close out inspection for GL 89-10, Safety Related Motor-Operated Valve Testing and Surveillance.

4.2 Electrical Maintenance - SBO Diesel Verification Test

The AAC DG provides the power source for onsite electrical loads during SBO conditions. DCP 92-052-3, AAC DG Installation, Surry Units 1 and 2, revision 0, installed the equipment. In accordance with the licensee's SBO commitment, documented in Virginia Power letter 92-292 to the NRC dated May 10, 1993, the licensee performed a special one-time demonstration test of the AAC DG capability. This test verified for Unit 1, the AAC DG ability to accept Unit 1 electrical loads within 10 minutes of the determination that an SBO condition existed. This capability included starting the AAC DG and completing the electrical alignment to energize the 1J emergency bus. The inspectors reviewed the verification test procedure and the completed AAC DG post modification test documentation. Additionally, the conduct of the verification test was observed and test problem resolution activity was reviewed to verify the test activities met the requirements of RG 1.155, Station Blackout.

The inspectors reviewed test procedure FDTP 92-052-3-6, AAC DG Installation Test, revision 0, to verify appropriate test instructions and acceptance criteria were specified. The procedure provided detailed instructions for equipment operation, establishing initial conditions, precautions, and designation of responsibilities for monitoring and communications. Appropriate sign-offs were provided to assure indicated actions were performed. The inspectors concluded that the test procedure provided adequate guidance for this special test activity.

The inspectors reviewed post modification test documentation for the previously completed testing which verified the four-hour 100 percent load capacity of the AAC DG and the generator control and interlock logic function. FDTP 92-052-3-3, AAC DG Installation Test, revision 0, was performed on June 21, 1995, and verified the four hour capacity. A test anomaly related to cylinder exhaust temperature monitoring was identified and adequately resolved. FDTP 92-052-3-2, AAC DG Installation Test, revision 0, was performed on September 15, 1995, and verified the logic function of starting the AAC DG and energizing the AAC DG 4160 V bus on an SBO signal. The inspectors concluded that the tests adequately verified the AAC DG capacity and starting logic.

The inspectors observed the test which verified the 10 minute response capability and AAC DG response to loading of a large pump. The test was initiated on September 27, 1995. The licensee's pretest briefing of operators and involved test personnel adequately addressed plant conditions and test evolutions. The initial portion of the test included phase rotation and synchronization checks of the breaker alignment from the 1J emergency bus to the AAC DG 4160 V bus. The inspectors observed appropriate personnel and equipment safety precautions and adherence to test procedure steps sequence.

The test was discontinued when a problem was identified with the breaker communication network that provided the permissive signal to allow manual closure of the control panel breakers to energize the 1J emergency bus from the AAC DG. A defect in the fiber optic communication network resulted in intermittent loss of the signal which communicated the condition of the D transfer bus to the programmable controller in the AAC DG control panel. The defect impacted the design capability of the AAC DG to energize the emergency bus. DR S-95-2291 was initiated to document the problem. The test was discontinued pending resolution of the problem.

The breaker communication network defect was identified to be a defective modem which was replaced. The test was continued on October 6. The inspectors observed that the AAC DG started and was aligned to the 1J emergency bus in less than the specified 10 minutes. The voltage response during loading was acceptable as evidenced by adequate margin being maintained between the voltage dip and the emergency bus low voltage setpoint. The test adequately verified the 10 minute capability for Unit 1 specified in the licensee's SBO commitment. The inspectors concluded that the test evolutions were adequately controlled, communications were appropriate, and overall test conduct was good. Test activities were conducted in accordance with the requirements of RG 1.155. Additionally, the test performance and resolution of a test problem demonstrated good communications between the operations, engineering, and maintenance organizations.

4.3 Corrective Actions to Improve Control Rod Reliability

The licensee experienced two dropped control rod operating events in May 1995. Causal factors and immediate corrective actions were previously documented in NRC IR 50-280, 281/95-08. The inspectors noted that, prior to the May rod control failures, recommended corrective actions from previous rod control RCEs to address the adverse rod control cabinet environment had not been implemented in a timely manner. RCE 95-08, Unit 2 Dropped Rod Event, assessed control rod system performance and identified several corrective actions to improve reliability. The inspectors reviewed RCE 95-08 and maintenance documents, conducted interviews, and observed maintenance activities to assess corrective action implementation.

RCE 95-08 identified sixteen corrective actions which were grouped into five categories; environmental, circuit card testing, circuit card handling, circuit card replacement, and enhancements. Management accepted all sixteen recommendations and CTS items were properly established. The inspectors verified that responsibility for each item was specifically assigned and observed that corrective actions were being implemented within the CTS specified schedules.

Rod control cabinet inspections and circuit card testing were performed by the vendor using procedure 0-NSID-EIS-85-11, Full Length Rod Control System Maintenance, revision 0, during the Unit 1 RFO. Testing included fifty spare rod control circuit cards in addition to all installed Unit 1 circuit cards. The inspectors observed portions of the circuit card testing and reviewed the completed test results. The circuit cards were generally in good condition based on the visual examination. However, circuit card bench testing identified eight discrepancies which were not evident by visual inspections. Each discrepancy was repaired with satisfactory retest results. The licensee also implemented 0-NSD-EIS-95-047, CRDM Timing Modification and Verification Testing, revision 0, to address industry concerns regarding a 1993 uncontrolled rod withdrawal at another nuclear facility.

Maintenance personnel completed several actions to improve their capability to verify circuit card performance prior to on-line installations. Technicians built a circuit card test device and developed procedure 0-ICM-RD-001, Rod Control Circuit Card Checkout, revision 0. Technicians now have the ability to conduct testing on regulation, failure detection, and signal processing cards as part of receipt inspection and prior to circuit card installation in the rod control cabinets. Prior to May 1995, receipt inspections were less comprehensive and were done by warehouse personnel. Technicians identified and corrected four circuit card discrepancies during circuit card receipt inspections for the Unit 1 RFO. The inspectors reviewed procedure 0-ICM-RD-001 and discussed circuit card test device construction with technicians. The recently developed test methods were consistent with vendor testing practices.

Prior to June 1995, the rod control cabinets operated in an environment which routinely exceeded the manufacturer's recommended temperature. RCE 95-08 concluded prolonged operation at excessive temperatures could reduce circuit card service life. The inspectors noted that twelve new phase control cards and eleven new voltage regulator cards were installed during the RFO to address accelerated aging concerns. Spot coolers were installed in June as a temporary modification to reduce rod control cabinet temperatures. The inspectors confirmed that a permanent modification to increase upper switchgear room cooling capacity is scheduled for installation this Winter. In addition, operators are now required to record upper switchgear room temperature each shift. If room temperature exceeds 83 degrees F, the operator must inform the SS and initiate a DR to correct the condition. The inspectors determined that licensee actions to address the adverse rod control cabinet operating environment were appropriate.

During the inspection period, maintenance and engineering personnel performed walkdowns of the CRDM containment electrical penetrations. All connections were satisfactory and no damage was identified on the cabling. The inspectors reviewed the WOs associated with these inspections and also inspected a limited sample of the electrical penetrations inside containment. The penetrations inspected were not damaged and appeared to be well protected.

The inspectors concluded that the licensee had properly implemented several positive initiatives to improve rod control system reliability. RCE 95-08 was thorough and established a comprehensive set of corrective actions which management has committed to implement. Although corrective actions are not yet complete, CTS items have been properly established and will be tracked to assure full implementation.

4.4 PZR Nozzle Leaks

On September 12, while performing a tagout on PZR level transmitter 1-RC-LT-1460, an operator noticed a slight boron buildup around the level tap nozzle upstream of isolation valve 1-RC-126 where the nozzle penetrates the PZR. This observation indicated a possible throughwall leak on the PZR penetration. A DR was initiated and on September 13, engineering walkdowns of the nine PZR instrument nozzles identified that another instrument nozzle upstream of 1-RC-130 also appeared to have a throughwall leak. There are four nozzles on the upper portion of the PZR and five instrument nozzles on the lower portion of the PZR. Both leaking nozzles were on the upper portion of the PZR and are located in the transition region between the shell and dome of the PZR. At the time of initial discovery, the RCS was depressurized and level was being maintained in the PZR.

Subsequent to opening the PZR manway, a visual inspection of the two suspect nozzles using a remote camera identified staining inside the PZR under the nozzles apparently originating from inside the nozzles. Based on the throughwall indications, the licensee developed DCP 95-036 to replace the defective nozzles with components manufactured from 316L stainless steel bar stock. In addition to performing detailed inspections of all four upper nozzles, the licensee also inspected two suspect lower nozzles. The inspection consisted of a visual inspection and a liquid penetrate examination conducted from outside the PZR. The penetrate examinations conducted on the leaking nozzles revealed a circumferential indication centered at 12 o'clock and extending through an arc of approximately 100 degrees on both nozzles. No indications were evident on the other four nozzles.

The licensee extracted the nozzle upstream of 1-RC-126 from the PZR. A detailed metallurgical examination is planned to determine the failure mode. With the unit at normal operating pressure, the licensee performed a cursory inspection of the Unit 2 PZR nozzle areas and did not identity any leakage. Insulation was not removed to perform the inspection.

The inspectors monitored the actions to identify and repair the leaking PZR nozzles throughout the reporting period. The licensee will submit an LER in accordance with 10 CFR 50.73 describing this event. The inspectors will review this item further when the licensee's failure analysis is complete. Operation's identification of the suspected RCS leak during tagging evolutions, demonstrated a good questioning attitude.

4.5 Control Rod Assembly Partial Movement, Procedure 2-OPT-RX-005, revision 5

The inspectors observed the performance of procedure 2-OPT-RX-005, revision 5, Control Rod Assembly Partial Movement. This procedure demonstrates the operability of the control rod assembly drive mechanisms and control circuits. The procedure implements TS 4.1, Table 4.1-2A requirements for quarterly partial movement of all control rods. The inspectors observed the procedure being performed on the D rod control bank. The evolution was conducted in accordance with the controlling procedure and the control bank met the acceptance criteria contained in the procedure for operability.

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

5. Engineering Review (37551)

Fuel Failure Review

Fuel sipping determined that three Unit 1 cycle 13 fuel assemblies contained fuel rods with failed cladding. Visual inspections were unable to determine the exact cause of the failures. Although one assembly may have been damaged by debris, the failures were in fuel assemblies that had experienced operating conditions similar to fuel assemblies that had failed during Unit 1 cycle 12.

Fuel sipping of Unit 1 cycle 12 fuel assemblies identified four with cladding failures. Visual and UT inspections, as well as, some single fuel rod examinations were unable to locate which fuel rod was leaking in the fuel assemblies. Thus, no failure mechanism was identified. Oxide measurements revealed approximately 4 or 5 mils more corrosion than anticipated. This information was incorporated into the Westinghouse corrosion model. Also, the four failed cycle 12 fuel assemblies had experienced similar exposure histories. These fuel assemblies had been burned twice before being located in the high power regime of the cycle 12 core. Thus, these assemblies had lead rods (the rod with the most burnup) with burnups in the mid-fifty thousand MWD/MTU range. The licensee's evaluation concluded that the high burnup and corrosion rates associated with the Zircaloy-4 cladding had been primary contributors to these cladding failures. This information was not available prior to the start of Unit 1 cycle 13.

To reduce the potential for fuel failures in Unit 1 cycle 14, twice burned fuel assemblies are being loaded into only low power core regimes, i.e., only around the core's periphery, and the lead rod burnup in the highest power fuel assemblies will be less than fifty thousand MWD/MTU. In addition, new fuel assemblies loaded into the core have ZIRLO cladding. Test assemblies with ZIRLO cladding have had measured corrosion rates less than half of that seen with assemblies clad in either Zircaloy-4 or improved Zircaloy-4. The inspectors agreed that these actions should reasonably preclude fuel rod failures due to burnup and corrosion during the upcoming Unit 1 cycle 14.

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

6. Plant Support (71707, 71750)

1A Station Battery Replacement

The licensee has demonstrated increased sensitivity to battery performance since an inoperable station battery event in October 1994 (see NRC IR 50-280, 281/94-32). RCE 95-03, Batteries, was performed to evaluate an increased number of battery performance problems and battery DRs which were observed during the first half of 1995. The inspectors noted that the RCE scope was comprehensive and recommended corrective actions were technically sound.

The most significant recommendations effected the station batteries. The 1A and 2A station batteries experienced repeated low cell voltages and electrolyte stratification. The 1A station battery was replaced during the Unit 1 RFO. The inspectors reviewed purchase order CNT 497969 and various receipt documents for the replacement Class 1E type GN-23 battery cells. Receipt documentation was complete and included successful factory performance and seismic testing documentation.

Procedure 1-EPT 0106-06, Main Station Battery 1A Refueling Performance Test, revision 3, was performed as a post installation test. The inspectors reviewed the test results with the system engineer. The battery successfully demonstrated 100 percent design capacity and met the requirements of TS 4.6.C.1.

The inspectors noted that the most significant cause of the repeated station battery DRs was the limited effectiveness of equalizing charges as a corrective maintenance. Equalization charge voltage has been limited due to DC bus limitations. The vendor recommends a higher equalizing charge voltage than is currently being used. Engineers have recommended two actions to address this limitation. The first action requires the station battery to be open circuited and connected to a portable charger strong enough to charge the entire 60 cell battery to the peak vendor recommended voltage (2.42 volts per cell). A periodic PM would be established to perform this charge during RFOs as needed. The second action involves individual cell charges which can be performed at manufacturer recommended voltages while the station battery is in service. The licensee has observed limited success using the individual cell charges alone. The system engineer informed the inspectors that plant modifications to support doing the elevated voltage equalizing charge are ahead of schedule. Unit 1 battery room wall penetrations for charging cable connections were installed during the Unit 1 RFO. The current schedule indicates that modifications to support the elevated voltage equalizing charge will be complete on both units by the end of 1996. The inspectors reviewed CTS item tracking for all RCE 95-03 recommendations. Each recommendation was accepted by management and was on schedule. The inspectors concluded that licensee actions to address battery degradation were appropriate.

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

7. TB Flooding (93702)

On September 14, flooding was reported in the Unit 1 TB. The inspectors responded to the TB basement in order to assess the extent of the event. Unit 1 was in CSD during the event. During preparation for inspections and maintenance on the C 96-inch CW inlet line, water entered Unit 1 TB basement via open 30-inch manways on the 96-inch CW and 48-inch SW lines. The previously dewatered C HL bay was found filling with water. Crews responded by installing an additional sump pump at the C HL bay, pumps in the TB basement were operated, and the 30-inch manway covers were reinstalled.

The licensee conducted a category 2 RCE to determine the causes of the event. The RCE assembled the following information:

Stop logs were installed in the A, C, and D HL bays and all three HL bays had been dewatered prior to the event. The B 96-inch intake was open and supplying SW to the CCHxs. The 96-inch blanks were installed in A and C bays. The 30-inch manways on the A and C headers were removed in the TB basement to allow access for inspections and repairs. Four four-inch hydraulic submersible sludge pumps were available at the HL. One was installed in each of the A, C, and D bays, with one spare. These type pumps are variable speed and are throttled to maintain a minimum water level in the HL bays.

At 5:00 a.m. on September 14, C HL north bay was reported dry and C south bay had 12 to 18-inches of water. A hydraulic sump pump was running in the sump in the north side of the C HL, maintaining the bay dry. A water level is normally present in the south bay of the C HL. The water normally spills over and collects in the sumps. This observation was considered normal inleakage past the stop logs.

The C 96-inch line in the TB basement was previously pumped down, via the opened manway, on night shift September 13. The 48-inch header manway was removed following pump down. At approximately 7:40 a.m. on September 14, TB craft were dewatering the A header. Personnel observed one to two feet of water in the C 96-inch pipe at the manway. This appearance of water did not alert the crew that any required corrective actions were necessary. They did not know the level of the previous shift's dewatering operation of the C header.

Between 8:15 a.m. and 8:30 a.m., TB craft observed the water level to be within one to two inches of the top of the pipe at the C 96-inch line manway in the TB basement. The foreman was notified of a potential problem and instructed the TB crew to install a prestaged electric pump in the C manway. The foreman went to the HLIS to verify that the C hydraulic sludge pump was operating.

At 8:40 a.m., the foreman informed personnel at the HLIS of the rising water level in the TB C 96-inch line. He instructed personnel at the HLIS to relocate the hydraulic sludge pump from the D bay to C bay to assist in pumping down the C bay.

At 9:00 a.m., personnel at the HLIS observed the water level was 1-inch to 2-inches from the top of the 96-inch blank and rising rapidly. The TB crew reported the electric pump was not keeping up with water inflow. At this point, water started coming out of the open 30-inch manways on the C 96-inch and 48-inch headers and running onto the floor.

At 9:17 a.m., the control room was notified of water on the floor in the TB. Operations dispatched operators to investigate. Operations initiated AP-13.

All personnel associated with the 96-inch line and HLIS work areas were accounted for.

The RCE determined that the root cause of the event was equipment performance. Design of the J-seal on the stop logs was questioned and is being reviewed by Engineering. There were several contributing causes to the event as well. They included lack of procedural controls for installing the 96-inch blank at the HL and the need for a HL floodwatch for future activities. Procedures are currently being developed to resolve these concerns. Completion of procedure implementation and J-seal design review is being tracked by the licensee's CTS.

The RCE associated with the September 14 TB flooding event, performed by the line organization, represented a commitment to identify and correct conditions which represent a high risk for core damage.

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

8. DR Review (40500)

The inspectors reviewed ten DRs issued at the beginning of the RFO to verify that equipment problems were being properly addressed. Specifically, the inspectors reviewed the proposed or actual corrective actions for DR S-95-2050, 2051, 2053-2059 and 2061 which were originated on September 9 and 10. The inspectors verified that WOs were issued when required and these WOs were either performed or planned to be completed prior to the end of the RFO if necessary, i.e., work that could only be performed while the unit was shutdown was not being deferred. Based on this sample, emergent equipment problems were being satisfactorily addressed.

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

9. Action on Previous Inspection Items (92701, 92901, 92902, 92903)

9.1 (Closed) IFI 50-280, 281/89-32-04, Resolve Inoperability Problem of Component Cooling Water (CCW) Service Water Radiation Monitor RM-SW-107

This item addressed a reliability problem with the CCW SW Hx RMs. The monitors experienced chronic failures due to frequent plugging of the sample line and jamming of the monitors' pumps with debris. The interim corrective action was periodic grab sampling and analysis of the system. The permanent corrective action was a design change to install a different type of RM.

The design changes were implemented in 1990 and 1992. DCP 89-15-3, Replacement of Rad Monitor RM-SW-107, dated February 28, 1990, and DCP 89-21-3, Installation of RM-SW-107A, B, and C, dated July 11, 1992, implemented the permanent corrective actions. The new design used sodium iodine crystal detectors and has provided continuous on-line monitoring since installation. The inspectors concluded the CCW SW RM operability problem had been resolved.

9.2 (Closed) IFI 50-280, 281/93-18-01, Followup of License Actions Associated with Surry Station Engineering Tracking Item No. 51353

This item addressed Appendix R Fire Protection Program compliance issues initially identified at North Anna and tracked at Surry via CTS Item No. 51353. The compliance issues were related to the licensee's commitments to NRC BTP 9.5-1 Appendix A guidelines and their incorporation into the licensee's Fire Protection Program. For example, the implementing Fire Protection Program documents did not include program administrative requirements specified in BTP 9.5-1 such as the designation of overall program ownership and personnel functional responsibilities. The licensee identified a similar finding in 1994 annual Quality Assurance Fire Protection Audit S94-10. Corrective actions included initiation of studies of Fire Protection Program commitments against program documents to verify implementation of commitments. Completion of the studies would then permit licensing actions to remove the Fire Protection Program from the station TSs.

The study to verify the BTP 9.5-1 Appendix A commitments was documented in NES 2791, tracked by CTS Item No. 51353 and completed on June 16, 1994. Six discrepancies were identified and resolved. The commitments of the Appendix R Safety Evaluation Reports were verified in study NES NP-3006, tracked by CTS Item No. 2826, and were completed on May 31, 1995. A licensee memorandum from L.T. Warnich, Corporate Fire Protection, to Licensing, dated June 12, 1995, specified that the station's actions to remove the Fire Protection Program from the TSs were complete. These actions included the verification of applicable commitments into the station Fire Protection Program. The inspectors reviewed VPAP-2401, Fire Protection Program, revision

3, and verified that program ownership and responsibilities were designated. Additionally, the inspectors verified the S94-10 audit findings were resolved. The inspectors concluded the Appendix R compliance issues identified by CTS Item No. 51353 had been resolved.

9.3 (Closed) IFI 50-280, 281/94-30-01, Review the Results of the Design Study of the Turbine Driven Auxiliary Feedwater (TDAFW) Pump Overspeed Trip Setpoint

This item addressed a problem with the reliability of the TDAFW pumps due to a relatively low overspeed trip setpoint. The trip point had been lowered in 1991 to 107 percent because the previous 125 percent setpoint permitted pressurization of the downstream piping above the design limits. The lowered trip setpoint reduced the margin between the normal operating speed and the overspeed trip condition. Subsequently, several pump trips occurred, usually during pump starting. Root cause investigation determined that a major contributor to the trips was binding of the governor valve due to build up of corrosion and minerals on the valve stem.

Interim corrective actions included replacement of the valve stem material with chrome plated steel and periodic cleaning and maintenance of the governor valve. Since the implementation of the interim actions in August 1994, there have been no additional TDAFW pump trips attributable to governor valve stem binding. Design Study NP-2945, TDAFW Pump Overspeed Trip Evaluation, was initiated to examine a long term resolution and was completed on July 12, 1995. The study provided six recommendations including reduction of normal operating speed, reduction of valve stroke, and installing inconel governor valve stems. The design change development for these recommendations was approved in the 1996 design budget. The inspectors concluded that the interim actions improved TDAFW pump reliability and that the licensee was appropriately addressing TDAFW pump overspeed trip problems.

10. Exit Interview

The inspection scope and findings were summarized on October 19, 1995, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results addressed in the summary section and those listed below.

Item Number	Status	Description/(Paragraph No.)
IFI 50-280, 281/89-32-04	Closed	Resolve Inoperability Problem of CCW SW Radiation Monitor RM-SW-107 (paragraph 9.1).

Item Number	Status	Description/(Paragraph No.)
IFI 50-280, 281/93-18-01	Closed	Followup of License Actions Associated With Surry Station Engineering Tracking Item No. 51353 (paragraph 9.2).
IFI 50-280, 281/94-30-01	Closed	Review the Results of the Design Study of the TDAFW Pump Overspeed Trip Setpoint (paragraph 9.3).

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

11. Index of Acronyms

AAC DG	ALTERNATE AC DIESEL GENERATOR
AC	ALTERNATING CURRENT
ASME	AMERICAN SOCIETY OF MECHANICAL ENGINEERS
BTP	BRANCH TECHNICAL POSITION
CC	COMPONENT COOLING
CCHx	COMPONENT COOLING HEAT EXCHANGER
CCW	COMPONENT COOLING WATER
CFR	CODE OF FEDERAL REGULATIONS
COF	COEFFICIENT OF FRICTION
CRDM	CONTROL ROD DRIVE MECHANISM
CSD	COLD SHUTDOWN
CTS	COMMITMENT TRACKING SYSTEM
CW	CIRCULATING WATER
DCP	DESIGN CHANGE PACKAGE
DR	DEVIATION REPORT
ECCS	EMERGENCY CORE COOLING SYSTEM
EDG	EMERGENCY DIESEL GENERATOR
ESF	ENGINEERED SAFETY FEATURE
FDTP	FINAL DESIGN TEST PROCEDURE
GL	GENERIC LETTER
HL	HIGH LEVEL
HLIS	HIGH LEVEL INTAKE STRUCTURE
Hx	HEAT EXCHANGER
IFI	INSPECTOR FOLLOWUP ITEM
IR	INSPECTION REPORT
ISI	INSERVICE INSPECTION
LER	LICENSEE EVENT REPORT
MOV	MOTOR OPERATED VALVE
MTU	METRIC TONS OF URANIUM
MWD	MEGAWATT DAYS
Na	SODIUM
NDE	NONDESTRUCTIVE EXAMINATION
NRC	NUCLEAR REGULATORY COMMISSION
PM	PREVENTIVE MAINTENANCE
PRT	PRESSURIZER RELIEF TANK

PSIG	POUNDS PER SQUARE INCH - GAGE
PZR	PRESSURIZER
RCE	ROOT CAUSE EVALUATION
RCP	REACTOR COOLANT PUMP
RCS	REACTOR COOLANT SYSTEM
RFO	REFUELING OUTAGE
RG	REGULATORY GUIDE
RHR	RESIDUAL HEAT REMOVAL
RM	RADIATION MONITOR
RO	REACTOR OPERATOR
SBO	STATION BLACKOUT
SS	SHIFT SUPERVISOR
SW	SERVICE WATER
TB	TURBINE BUILDING
TDAFW	TURBINE DRIVEN AUXILIARY FEEDWATER
TS	TECHNICAL SPECIFICATION
UT	ULTRASOUND TEST
V	VOLTS
VPAP	VIRGINIA POWER ADMINISTRATIVE PROCEDURE
WO	WORK ORDER