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

Report Nos.: 50-280/93-24 and 50-281/93-24

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: October 3 through November 6, 1993

Inspectors:

L. W. Garner for — 11-30-93
M. W. Branch Senior Resident Inspector — Date Signed

L. W. Garner for — 11-30-93
J. W. York, Resident Inspector — Date Signed

L. W. Garner for — 11-30-93
S. G. Tingen, Resident Inspector — Date Signed

Approved by: K. D. Landis — 11/30/93
G. A. Belisle, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of plant status, operational safety verification, maintenance inspections, surveillance inspections, balance of plant inspection, action on previous inspection items, emergency response training for off-site support groups and engineered safety feature system walkdown. While performing this inspection, the resident inspectors conducted reviews of the licensee's backshifts, holiday or weekend operations on October 12, 21, 26, 30, 31 and November 1, 2, and 3, 1993.

Results:

In the Operations area, the following items were noted:

Measures implemented to compensate for reactor coolant system leaking into the Unit 1 B safety injection accumulator did not prevent the boron concentration in the accumulator from decreasing below the Technical Specification (TS) minimum requirements on two occasions (paragraph 3.e).

The initial Station Nuclear Safety and Operating Committee screening of the deviation report documenting that boron concentration in the Unit 1 B safety injection accumulator was below TS minimum requirements categorized the event as not reportable. After additional engineering review, the event was considered reportable. A licensee event report will be written (paragraph 3.e).

Although the licensee had recently completed a component relabeling program, seven components in the Unit 1 and 2 charging pump service water support systems were not labeled with the new label plates (paragraph 9).

In the Maintenance/Surveillance area, the following items were noted:

During the period, two Unit 1 rod control system problems occurred that resulted in rod control system urgent failure alarms (paragraphs 3.a and 4.c).

During summer months, recurring operational problems with the 555-ton mechanical chiller condensers continued to cause entry into TS action statements for containment partial pressure. This challenged operators unnecessarily (paragraph 3.f).

The licensee's temporary leak sealant program was identified as a strength (paragraph 4.a).

During the previous Unit 2 refueling outage, a new type of packing was installed in the auxiliary feed water pumps that required special installation and run-in instructions. The packing was installed correctly but the process could have been done more efficiently (paragraph 4.e).

The use of the motor operated valve diagnostic equipment for troubleshooting the reactor trip bypass breaker was innovative, provided the licensee with additional diagnostic information, and was considered a strength (paragraph 4.b).

During reactor protection system logic testing, the inspectors observed good communication between all parties, as well as, good self checking techniques by the personnel manipulating the test switches. This was considered extremely important since the procedure directed approximately 500 various switch operations (paragraph 5).

In the Engineering/Technical Support area, the following item was identified:

> The licensee's ability to utilize advanced metallurgical analysis techniques for failure analysis cases, such as the cast aluminum-bronze service water valves, was a continuing strength (paragraph 3.b).

In the Plant Support area, the following item was noted:

> The licensee was proactive in working with the state and local governments in resolving Federal Emergency Management Agency emergency exercise items (paragraph 8).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

W. Benthall, Supervisor, Licensing
* R. Bilyeu, Licensing Engineer
* H. Blake, Jr., Superintendent of Nuclear Site Services
* R. Blount, Superintendent of Maintenance
D. Christian, Assistant Station Manager
J. Costello, Station Coordinator, Emergency Preparedness
* J. Downs, Superintendent of Outage and Planning
* D. Erickson, Superintendent of Radiation Protection
A. Friedman, Superintendent of Nuclear Training
B. Hargrave, Nuclear Materials
* M. Kansler, Station Manager
* C. Luffman, Superintendent, Security
* J. McCarthy, Assistant Station Manager (Acting)
* A. Price, Assistant Station Manager
* K. Sloane, Superintendent of Operations (Acting)
* M. Small, Senior Reactor Operator
* E. Smith, Site Quality Assurance Manager
* D. Souza, Senior Reactor Operator
* T. Sowers, Superintendent of Engineering
J. Swientoniewski, Supervisor, Station Nuclear Safety

NRC Personnel

* M. Branch, Senior Resident Inspector
* 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 operated at full power for the majority of this inspection period. On November 4, the unit began a power coast down. At the end of the inspection period the unit was at 98% power.

Unit 2 operated at approximately 98% power throughout the period in order to minimize level oscillation in the C SG.

3. Operational Safety Verification (71707, 42700)

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.

a. Unit 1 Control Rod Drive System Urgent Failure Alarms

At 6:24 a.m., on October 13, a Unit 1 rod control system urgent failure alarm was received. By design, an urgent failure locks up the rod control system and prevents normal rod motion. It does not prevent rods from tripping into the core if a protective actuation was initiated. A two hour TS action statement to clear the alarm was entered in accordance with TS 3.12.C.3. At 8:24 a.m., the two hour action statement was exited and a six hour action statement to HSD was entered. The rod control internal alarm was reset and the urgent failure alarm cleared. The cause for the urgent failure alarm was not determined. Procedure 1-PT-6, Control Rod Assembly Partial Movement, was satisfactorily performed and the six hour action statement was exited.

On October 21, another rod control system urgent failure alarm occurred in Unit 1. This event is discussed in paragraph 3.d and 4.c.

b. Through-Wall Leaks in SW Valve Bodies

On October 12, the licensee documented a deficient condition on DR S-93-1350 which involved several valves in the SW system used for charging pump lube oil and seal cooling. The DR described a condition where SW was seeping through what appeared to be porosity in the cast valve bodies. Eleven valves from each unit exhibited some degree of corrosion attack, from weepage to visual corrosion products present on the outside of the valves.

The portion of the SW system with the leaking valves provided cooling water to the charging pump lubricating oil and seal cooler heat exchanger. These leaking Jamesbury ball valves provided maintenance isolation capability. This low pressure system (approximately 45 psi) normally flows approximately 50 gpm and varies on a seasonal basis. The flow velocity is sometimes as low as two to three feet per second. Flow below approximately five feet per second lends the system to the potential to fouling which can promote the formation of MIC nodules.

The SW valves in question are cast aluminum-bronze, alloy C 95400. After discovering the problem, the licensee replaced several valves that exhibited through-wall leakage. Originally, this system was constructed of plastic components. In 1986 because of Appendix R considerations, the components were changed to aluminum-bronze.

The valves that were removed were taken to the site metallurgical laboratory for determining the failure mechanism. A chemical analysis of one of the cast valves showed that the chemical composition requirements in ASTM B 148, Standard Specification for Aluminum-Bronze Sand Castings, were met.

Cross sections of leaking areas (under MIC nodules) revealed that the aluminum rich phases had been leached out leaving a porous structure through which the weeping/leaking occurred. Also, this examination showed that the through-wall dealloying did not exceed 25 percent of the circumference for any given cross section. Corrosion product analysis on the outside of the valves showed a large percentage of aluminum thus confirming the dealloying process.

Some sections from the first valve removed were used to perform tensile tests. Samples were taken from the unaffected, as well as, the dealloyed sections of the cast material. The visual and metallographic evaluations, along with the tensile tests results, were used as the basis for the licensee's evaluation that the valves would maintain their structural integrity in the identified degraded condition until they could be replaced.

Discussions between the licensee and the NRC concluded that the licensee needed to request relief from the ASME Section XI Code in order to continue to operate without immediate repair of the defects. This determination was consistent with the guidance contained in GL 91-18 and 90-05. The licensee indicated that they disagreed with the NRC's interpretation on addressing operational leakage under the ASME Code. However, after determining structural integrity of the valves in question, the licensee indicated that they would comply with the NRC's interpretation for this case and on November 2, a relief request was submitted for NRC's review. The licensee indicated that they plan to address this issue further and have requested a meeting with the NRC to present their position.

The inspectors are following the licensee's actions to evaluate the root cause of the material failure, the reportability of the issue, and replacement of the defected valves. At the end of the inspection period, the licensee had replaced some of the SW valves that were subject to through-wall leakage and were developing plans for replacing the remaining valves. The licensee's ability to utilize advanced metallurgical analysis techniques for failure

analysis cases, such as the cast aluminum-bronze service water valves, is a continuing strength.

c. Unit 2 C SG Special Test

Since Unit 2 startup in May of 1993, the C SG has experienced level oscillation whenever attempts were made to increase reactor power to 100%. Consequently, the unit operated at a reduced power of approximately 98%. The licensee's original investigation centered around FW flow control. Gain adjustments were made to the C FWRV in an attempt to dampen the SG level oscillations. The adjustments to the FWRV controls did slow down the valve's response to level oscillations; however, it was unsuccessful in resolving the level oscillations to a point that power could be increased back to 100%.

The licensee contracted a failure analysis expert in an attempt to find other possible causes for the level oscillations. Additionally, the licensee held discussions with their NSSS and SG supplier to determine if other plants had experienced this type of SG level phenomenon. There were several possible causes discussed which refocused the licensee's attentions to possible mechanical or thermodynamic changes internal to the SG. The possible internal causes included damage to the feedwater "J-Tube", or sludge buildup in the upper tube support region of the SG. During a forced shutdown in August 1993, the licensee performed a limited visual inspection of the internals of the C SG through restrictive openings and no obvious defects were identified.

The inspectors reviewed the safety evaluation (93-196) that supported the special test (2-ST-306) and attended the pre-shift operating crew briefing. The scope and precautions contained in the test procedure were discussed in detail and questions were directed to the test director who resolved them in an acceptable manner.

The test entailed raising the C SG program level from the normal 44% to 49% and monitoring the SG for level oscillations, both at the existing 98% reactor power and at 100% power. The test directed holding at this new SG level for 48 hours and then raising the program level to 54% and monitoring the resultant plant response for an additional 48 hours.

At the 98% reactor power, the level oscillations in the C SG appeared to have stabilized after the program level was increased to 49%. However, when reactor power was increased to 100%, the maximum level (on the narrow range instrumentation) oscillation of +/- 20% magnitude was experienced. The operators stabilized the SG level in accordance with the precautions of the special test procedure and the test was suspended at the direction of the SS and test director. After reviewing the test results, plant management directed that the C SG level setpoint be returned to

the 44% value and that reactor power be controlled to minimize level oscillations.

The C SG level setpoints were returned to the 44% value and reactor power was lowered to 98%, and level oscillation was reduced to the pre-test value. The inspectors continued to monitor the licensee's corrective actions in this area and will review any C SG planned outage related activities.

d. Notice of Enforcement Discretion

On October 21, the NRC granted Enforcement Discretion to TS 3.12.C.3 for Unit 1 only. On October 21, the Unit 1 Bank D control rod assemblies became inoperable when a rod control system urgent failure alarm occurred when operators were performing 1-PT-6, Control Rod Assembly Partial Movement. TS 3.12.C.3 requires that inoperable control rod assemblies be restored to operable status within 2 hours or that the plant be put into a hot shutdown condition within the next 6 hours. The discretion permitted continued operation of Surry Unit 1 in Power Operation for a period of 72 hours versus the 2 hours specified in TS 3.12.C.3. This additional time was projected to allow troubleshooting and possible repairs to the Control Rod Drive System. Although the Bank D control rod assemblies were immovable on demand from the Control Rod Drive System, the ability of the control rod assemblies to perform their intended safety function (trip into the core) when a safety system setting was reached was not effected. A blown fuse was identified as the cause of the rod control system urgent failure alarm which resulted in the immovable Bank D control rod assemblies. The fuse was replaced and the control rods were satisfactorily tested in accordance with 1-PT-6. The Control Rod Drive System was returned to operable status approximately one hour after the Notice of Enforcement Discretion as verbally approved by the NRC.

Since rod control system failures appear to be a continuing problem, the NRC requested the licensee discuss their assessment of previous failures with NRC management. The inspectors continue to monitor the licensee's rod control system reliability improvement activities and are currently reviewing the RCM study of that system and the status of implementing any recommended corrective actions.

e. Unit 1 B Accumulator In-Leakage

On October 9 and 15, 1993, sample analyses from the Unit 1 B accumulator revealed that the boron concentration was less than the minimum required by TS. It was suspected that back leakage from the RCS through the accumulator check valves diluted the boron concentration in the accumulator. TS 3.3.B states that any one of the following SI components may be inoperable at any one time and that if the condition is not restored within the allowed

time period then the unit must be placed in hot shutdown within 6 hours. TS 3.3.B.1 states that one accumulator may be isolated for a period not to exceed 4 hours.

On both occasions when the boron concentration was out of tolerance, the licensee declared the B accumulator inoperable in accordance with TSs 3.3.B and 3.3.B.1 and entered a four hour action statement to restore the accumulator to an operable status. On both occasions, the boron concentration was restored within four hours. The accumulator was not isolated at any time during these evolutions. The inspectors discussed the licensee's interpretation of TS 3.3.B.1 with the NRC staff and concluded that the licensee correctly interpreted the TSs. Although the boron concentration was low, it was still significantly higher than RCS boron concentration and could have discharged into the RCS if needed. This condition was more conservative than a condition where the accumulator would have been isolated and not available.

SI accumulator levels are logged every shift. The inspectors reviewed the logs for the B SI accumulator level from July 1 through November 1, 1993, and concluded that around September 1 levels began to increase due to leakage into the accumulator. Prior to September 1, coolant was leaking out of the accumulator and the accumulator had to be filled approximately every 10 days. After September 1, small amounts of water were drained from the accumulator to reduce level approximately every three to four days. The inspectors concluded that measures implemented to compensate for leakage of reactor coolant into the Unit 1 B safety injection accumulator did not prevent the boron concentration in the accumulator from decreasing below the TS minimum requirements on two occasions.

The inspectors also reviewed the licensee's reportability determination for this event. VPAP-1501, Station Deviation Reports, Revision 3, states that the SS makes the initial reportability determination and this determination is reviewed by the Superintendent of Operations, SNS supervisor, and SNSOC. The inspectors reviewed DR S-93-1372. This DR documented that on October 15 the boron concentration in the Unit 1 B SI accumulator was below the minimum TS requirements. The inspectors noted that this event was initially categorized as not reportable. The inspectors and other station personnel questioned if the boron concentration was less than required by TSs for a period greater than fours hours allowed by the licensee's TS interpretation discussed above. Engineering reviewed this event and concluded that the boron concentration was less than required by TS for a period greater than four hours. The licensee subsequently identified that this event was reportable by an LER.

At the end of the inspection period, the licensee was preparing an LER and was evaluating corrective action to reduce leakage into the Unit 1 B SI accumulator. The licensee was also sampling the B

accumulator every two days to verify proper boron concentration. The inspectors will review the licensee's LER on this issue to determine if any additional actions are necessary.

f. Containment Partial Pressure Less Than 9.0 PSIA

TS Figure 3.8.1 requires that containment partial air pressure be maintained greater than or equal to 9.0 psia. TS 3.8.D.1.a specifies that if containment partial air pressure is less than 9.0 psia then containment air partial pressure must be restored to within acceptable limits within one hour or be in at least hot shutdown within the next six hours.

The inspectors noted, and the licensee's trending programs confirmed, that in the summer months a one-hour action statement had been entered in accordance with TS 3.8.D.1.a on numerous occasions in both units because indicated containment partial air pressure fell below 9.0 psia. In 1992 and 1993 there were at least six and fourteen DRs, respectively, written to document that a one hour action statement was entered because containment partial air pressure was less that 9.0 psia.

Operational problems with the 555-ton mechanical chillers which normally are used only during the summer months cause indicated containment partial air pressure to decrease below 9.0 psia. The licensee has appointed a task team and initiated a station Level I action item to improve the operation of the 555-ton mechanical chillers; however, operators have been routinely challenged to restore containment partial air pressure on a recurring basis during the summer months. The inspectors are continuing to follow this issue.

g. Air Leak on EDG #1

During a backshift tour on November 2, the inspectors noted that air was blowing by the seat of valve 1-EG-18. The valve is a manual strainer blowdown valve on one of the two banks of EDG starting air. The air accumulator pressure was normal and no low pressure alarms were lit. The inspectors notified the SS and an operator was dispatched to investigate. The operator checked the valve closed and then attempted to blow any trash from the seat by cracking open the valve. The low pressure alarm was actuated during the blowdown and the operator reclosed the valve and allowed the compressor to recover pressure above the alarm setpoint. The blowdown reduced the leakage somewhat; however, the valve continued to leak and WR 027327 was initiated to repair the valve.

Within the areas inspected, no violations were identified.

4. Maintenance Inspections (62703) (42700)

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

a. Inspection of Leak Sealant Practices

The site utilized contractors to repair leaks with temporary leak sealant. Temporary leak sealant has been used to repair a variety of leaks. The process involves drilling and tapping a valve bonnet, flange, manway cover or packing gland, and installing injection adapters. An injection gun is utilized to inject leak sealant into the adapter and the desired area. In other instances, a box is built around a leak and the box is injected with leak sealant or sealant can be utilized to plug a valve that has excessive seat leakage. Temporary leak sealant can be utilized on safety and non-safety systems; however, the use of temporary sealant on safety systems is minimized. Generally a rubber based sealant is utilized on systems less than 460 degrees F and a synthetic fiber based sealant utilized on systems up to 1000 degrees F. Whenever a temporary leak sealant is utilized to repair a leak, a WR is processed to restore the component back to original specifications during the next scheduled outage of sufficient duration.

Generic procedure O-MCM-1918-01, On-Line Leak Repairs, provides guidelines for the temporary leak sealant of components in safety and non-safety related systems. This procedure was approved by SNSOC and required that engineering approve using a temporary leak sealant for repair. Engineering is extensively involved when a temporary leak sealant is used. Design Engineering is required to evaluate stress, seismic calculations, the need for additional supports, and design pressure when utilizing a temporary leak sealant. System Engineering evaluates the impact of repair on system operation, potential for blockage, and the affect of intrusion of sealant into the system being injected. Engineering is also required to perform a safety evaluation screening for the temporary repair in order to determine if the evolution is a modification. Engineering is required to specify any post maintenance testing that may be required and evaluate if repair meets ASME specifications. Generally the temporary leak sealant contractor calculates the injection pressure and the amount of sealant to inject. This calculation is reviewed by engineering. Personnel cannot inject more sealant than specified for the job. Normally injecting temporary sealant to repair a leak is considered maintenance and not a modification. Procedure O-MCM-1918-01, Step 6.1.11, required that the SNSOC review and approve each work package for the repair of a leak with a temporary leak sealant when the leak is located inside containment with the unit operating. Work packages for injecting sealant into components located outside of the containment did not require SNSOC review

and approval. The QA department reviewed the work package prior to performance and specified hold point requirements.

There have been no recent issues or problems due to the inappropriate use of sealant for temporary leak repairs. The inspectors were informed that in the 1970s and early 1980s there was a issue associated with contaminates in the sealant which contributed to bolting failures on the main steam trip valves and main feedwater regulating valves which were resolved. The licensee's temporary sealant program was identified as a strength.

b. Unit 1 B Reactor Trip Bypass Breaker Troubleshooting

On October 15, while the licensee was performing 1-PT-8.1, Reactor Protection System Logic, for the B RPS train, the closed indicator light for the B RTBB went out after the breaker was closed for testing purposes. The licensee's investigation identified that a 10 amp fuse in the circuit had blown. The fuse was subsequently replaced and it blew again after the breaker was closed. The RTBB was opened after the main RTB was verified closed and the licensee initiated troubleshooting to determine the cause of the blown fuse. The RTBB is normally open and is used solely for testing purposes and when closed its safety function is to open if a RPS signal is received.

The inspectors witnessed some troubleshooting and subsequent testing of the breaker after repairs. The troubleshooting had indicated that the closing solenoid coil was drawing excessive current because it was kept energized longer than designed. The licensee used test equipment normally used for MOV testing to monitor and record the current being drawn by the closing coil. Using this equipment allowed the licensee to determine that the control (X) relay that deenergizes the closing coil solenoid was not actuating as required. The mechanical linkage (relay release arm) between the closing coil solenoid push rod and the relay was not properly adjusted. The licensee replaced the closing coil solenoid, the X relay, and adjusted the linkage prior to breaker reinstallation and successful retesting.

The use of the MOV diagnostic equipment for troubleshooting the RTBB was innovative and provided the licensee with additional diagnostic information and was considered a strength.

c. Troubleshooting the Rod Control System Urgent Failure Alarm

On October 21, the licensee, while performing a periodic test, received a rod control system urgent failure alarm when moving control D bank. The failure was determined to be in the 01-RD-CAB-1BD power cabinet. The inspectors observed technicians performing troubleshooting which included electrical measurements in the affected cabinet. From the readings taken, it was suspected that the B phase fuse on the supply power lines to the

movable coil circuit was blown. The licensee requested enforcement discretion, which was discussed in paragraph 3.d, in order to proceed with the fuse replacement and testing in an orderly manner. At the conclusion of the troubleshooting the licensee processed a WO and the blown fuse was replaced. Procedure IMP-C-EPCR-46, Maintenance of Rod Control System, dated December 22, 1992 was used to control the work. Periodic test 1-PT-6 was performed on the D control bank and the rod control system was returned to service. Good coordination between the two maintenance groups was noted and no problems were identified by the inspectors.

d. Fuse Schedule Inspection

The inspectors reviewed 1-DRP-002, Instrument Fuse Schedule, Revision 5 and 2-DRP-015, Power Fuse Schedule, Revision 0. The purpose of these procedures is to provide a fuse control program for the most critical fuses in the units. When replacing a fuse or when obtaining fuse reference data, these procedures are to be used in lieu of electrical drawings. If a fuse schedule does not contain a specific fuse, then the information is obtained from an electrical drawing or engineering.

Fuse schedules are generally not utilized when isolating electrical components. The locations of fuses required to be removed for isolation are generally obtained from drawings and the same fuses are reinstalled when returning the component/system back to service. Through discussions with operators and electricians the inspectors were informed that as a good working practice, personnel routinely inspect fuses that are removed to verify that the fuse specifications are the same as the specifications on the drawing. Any discrepancies are resolved.

During the EDSFA conducted by the licensee, the following concerns were identified with the fuse schedules:

Not all fuses in the fuse schedules were analytically verified against design basis.

The fuse schedules were not complete in that they did not contain all critical plant fuses and in some instances did not specify all fuse data for a specific fuse.

Electrical department personnel were not aware that the power fuse schedule was an approved document.

There were inconsistencies between fuse schedules and ESK drawings.

Training was provided to ensure personnel were knowledgeable of the fuse schedules. The remaining concerns have not been fully

resolved but are scheduled to be resolved during future EDSFA followup inspections performed by the licensee.

e. Unit 2 A Auxiliary Feed Pump Repack

On October 29, the inspectors witnessed the licensee repacking AFW pump 2-FW-P-3A. WO 274804 and procedure O-MCM-0131-01, General Pump Packing, Revision 0, were utilized to accomplish this maintenance. The inspectors reviewed the work package at the job site while the mechanics were repacking the pump. The mechanics received guidance from maintenance engineering personnel. After maintenance was completed and the pump was returned to service, the inspectors reviewed the work package a second time. During the second review, the inspectors noted that the work package contained additional instructions for repacking the pump and running the new packing that were added after the pump was repacked. The additional instructions were provided in an Information Transmittal Record from maintenance engineering.

The inspectors questioned why these instructions were not on the job site when the work was accomplished. The inspectors were informed that during the previous Unit 2 RFO a different type packing was installed in the AFW pumps. The new packing required different installation and run in methods than the previous packing. The inspectors were informed that prior to repacking the pump on October 29, maintenance personnel were briefed on the installation and run in methods for the new packing and maintenance engineering subsequently documented what was done in the Information Transmittal Record.

The inspectors concluded that the packing was properly installed in the A AFW pump; however, this maintenance would have been accomplished more efficiently if mechanics or procedures recognized the special instructions associated with the new type of packing. The need for an Information Transmittal Record indicated that the work package/training provided for the mechanics was lacking all the necessary information to accomplish the maintenance and maintenance engineering support was required to augment the work package.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726, 42700)

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

On October 15, the inspectors witnessed the licensee performing 1-PT-8.1 for the B RPS train. This testing was being performed as additional testing for the repairs of the B RTBB discussed in paragraph 4.b to verify that the protective logic was not affected by the breaker

repairs. The inspectors monitored activities at the test panel in the protection racks. Communications between the I&C technicians at the RTBB, in the control room, and at the test panel were also monitored. The inspectors observed good communication between all parties, as well as, good self checking techniques by the personnel manipulating the test switches. The inspectors considered this to be extremely important since the procedure directed approximately 500 various switch operations.

Within the areas inspected, no violations were identified.

6. Balance Of Plant Inspection (71500)

The inspectors conducted tours of portions of the TB and other plant areas susceptible to flooding. During these tours, the inspectors verified the availability of the non-safety related TB sump pumps. The licensee relies on these pumps to mitigate certain flooding scenarios. Additionally, the inspectors were sensitive to any work activities that would increase the possibility of TB flooding such as openings in the condenser waterboxes or piping systems.

a. Hole In Unit 2 D CW Discharge Piping

During the plant tour on October 13, the inspectors became aware of a one-inch diameter hole in the 96-inch CW discharge piping from the Unit 2 D waterbox. This non-safety related piping was designed to AWWA specification and it is isolable from the gravity flow intake canal by closing the 96-inch safety-related waterbox inlet MOV. The condition of the waterbox discharge piping for all four Unit 2 waterboxes was observed by the inspectors. There was evidence of previous welded overlay plate repairs to several of the pipes. The area where the hole was discovered was rusted through and crumbled further when probed by the inspectors. Although no leakage was noted, the C waterbox discharge piping appeared to be corroded in the area near the floor level where standing water had previously accumulated.

The inspectors discussed the observed conditions with the system engineer and reviewed the Surry IPE for sensitivity of a possible failure of the 96-inch waterbox discharge piping. The pipe in question is not routinely inspected. Five of the eight CW supply pipes are currently being inspected as part of the licensee's SW system inspection developed as part of GL 89-13, SW System Problems Affecting Safety-Related Equipment. The three CW supply pipes currently not routinely inspected do not supply the SW system and were not included in the program.

The inspectors' IPE finding review concluded that a catastrophic failure of the outlet piping was not considered since the inlet MOV should close and isolate the leak. The licensee's IPE considered the condenser waterbox as the weak-link for an isolable failure. The IPE described the probability of the inlet MOV not

closing and when multiplied by the probability of a waterbox failure, the results were within acceptable IPE values. The licensee's IPE personnel indicated that even with the observed conditions of the discharge piping, the probability of a catastrophic failure would still be bounded by the weak-link analysis. They further stated that it would not be valid to multiply the probability of a MOV failing to close times a probability of 1 for the discharge piping failure.

The inspectors discussed the IPE issue with regional personnel and concluded that the licensee's PRA evaluation of the impact of the observed condition of the discharge piping was reasonable.

b. Water Bubbling From Floor Near Unit 2 D CW Pipe

On October 26, DR S-93-1394 documented a condition where the operators identified that water was bubbling up through a crack in the floor near the Unit 2 D CW supply line to the condenser. DR S-93-1394 indicated that the water was sampled and determined to be greater than 5000 ppm sodium (similar to raw river water). The inspectors walked down the area. Water was bubbling from two locations in a concrete expansion joint approximately two feet from where the D CW supply line penetrated the floor. The leakage rate was difficult to estimate. It was estimated to be one gpm.

The inspectors were initially concerned because the sodium concentration in the sample indicated that the water may have been CW which also contains approximately 5000 ppm sodium. Subsequent samples indicated that the water was substantially less than 5000 ppm sodium. The inspectors witnessed personnel collecting water bubbling from the expansion joint and also observed chemistry department personnel analyze the sample for sodium. A Flame Emission Spectrometer was used to analyze the sample. The sample results indicated that it contained 1020 ppm sodium. The inspectors also observed personnel analyze a sample of CW for sodium concentration. The results of the CW sample indicated that it contained 5400 ppm sodium. It was undetermined why the sodium concentration in the first water obtained from the expansion joint was higher than the samples obtained later.

Per the licensee, ground water samples obtained just outside of the turbine building contained approximately 500 ppm sodium. The inspectors concluded the water bubbling through the turbine building floor appeared to be a mixture of ground water and CW due to the elevated concentration of sodium. The source of the CW is unknown.

The inspectors considered the possibility that the leakage was from the underground D CW supply line which is ASME code class III piping. The inspectors reviewed CW piping drawing 11548-FC-2C and verified that the 96-inch carbon steel CW piping beneath the turbine building floor was enclosed in 18 inches of concrete. The

drawing also depicted mechanical transition joints between the concrete intake structure piping and the 96-inch steel inlet piping which the licensee indicated could also be the source of the leakage. The inspectors were informed that previous inspections of the interior of this piping have not revealed through wall defects. At the end of the inspection period the licensee was evaluating methods to determine the source of the leakage.

Within the areas inspected, no violations were identified.

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

(Closed) VIO 50-281/91-20-01, Interval Between Surveillance of Unit 2 Hot Channel Factors Exceeded TS Requirements. TS 3.12.B.2 requires that hot channel factors be determined every EFPM and TS 4.0.2 allows a 25% tolerance. The Unit 2 hot channel factors were determined on July 18 and September 4, 1990. This violation was identified because the interval between these hot channel factors was 1.44 EFPM which exceeded the allowable 1.25 EFPM. In a letter dated October 16, 1991, the licensee responded to this violation. The licensee determined that the cause of the violation was improper interpretation of TS grace period tolerances and that administrative limits to clearly define allowed grace period limitations were implemented as corrective action. The inspectors reviewed VPAP-1102, Periodic Testing, Revision 0, and verified that administrative limits for specifying TS grace period limitations were clearly defined. The inspectors also reviewed procedures that performed hot channel factors for Units 1 and 2 during 1993 and verified that the hot channel factors were performed within the specified TS intervals.

Within the areas inspected, no violations were identified.

8. Emergency Preparedness Training For Off-Site Support Groups

Throughout 1993 Virginia Power has provided emergency preparedness training for state and local government personnel. On October 26, the inspectors witnessed several training sessions where Virginia Power personnel instructed personnel from Surry, Newport News, Isle of Wight, Richmond, Hampton, Smithfield and Petersburg in the areas of radiological contamination, personal dosimetry and exposure control. Areas emphasized during these training sessions included training in corrective actions for previously identified FEMA items. The inspectors concluded that the licensee was proactive in working with state and local governments in resolving FEMA emergency exercise items.

Within the areas inspected, no violations were identified.

9. ESF Walkdown (71710)

The inspectors walked down the Unit 1 and 2 charging pump/HHSI SW support systems. These systems provide cooling water to each

charging/HHSI pump lube oil cooler and to the intermediate seal coolers. Drawings 11448-FM-071B, Revision 30 and 11548, Revision 31, were utilized for the system walkdown.

During the walkdown the inspectors noted that the following components were missing the new style label plates:

Duplex strainers 2-SW-S-2A, 1-SW-S-2A and 1-SW-S-2B.
Valves 2-SW-438, 2-SW-170 and 1-SW-271.
Check valve 2-SW-130.

The inspectors concluded that although the licensee had recently completed a component relabeling program, seven components in the Unit 1 and 2 charging pump SW support systems were not labeled with the new label plates. This issue was discussed with the licensee.

The remaining deficiencies noted during the walkdown were previously identified by the licensee and were annotated with WR tags. The inspectors also noted that there was through-wall weepage on some of the valves in the system. This issue was discussed in paragraph 3.b.

Within the areas inspected, no violations were identified.

10. Exit Interview

The inspection results were summarized on November 9, 1993, with those individuals identified by an asterisk in Paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below and in the Results section. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Status	Description (Paragraph No.)
VIO 50-281/91-20-01	Closed	Interval Between Surveillance of Unit 2 Hot Channel Factors Exceeded TS Requirements (paragraph 7).

11. Index of Acronyms and Initialisms

ASTM - AMERICAN SOCIETY FOR TESTING AND MATERIALS
AFW - AUXILIARY FEEDWATER
AMP - AMPERE
ASME - AMERICAN SOCIETY OF MECHANICAL ENGINEERS
AWWA - AMERICAN WATER WORKS ASSOCIATION
BOP - BALANCE OF PLANT
CW - CIRCULATING WATER
DR - DEVIATION REPORT
ECCS - EMERGENCY CORE COOLING SYSTEM
EDG - EMERGENCY DIESEL GENERATOR

EDSFA	-	ELECTRICAL DISTRIBUTION SYSTEM FUNCTIONAL ASSESSMENT
EFPM	-	EFFECTIVE FULL POWER MONTH
ESF	-	ENGINEERED SAFETY FEATURE
ESK	-	ELECTRICAL SKETCH
F	-	FAHRENHEIT
FEMA	-	FEDERAL EMERGENCY MANAGEMENT AGENCY
FW	-	FEEDWATER
FWRV	-	FEEDWATER REGULATING VALVE
GL	-	GENERIC LETTER
GPM	-	GALLONS PER MINUTE
HHSI	-	HIGH HEAD SAFETY INJECTION
HSD	-	HOT SHUTDOWN
I&C	-	INSTRUMENTATION AND CALIBRATION
IPE	-	INDEPENDENT PLANT EVALUATION
LER	-	LICENSEE EVENT REPORT
MIC	-	MICROBIOLOGICAL INDUCED CORROSION
MOV	-	MOTOR OPERATED VALVE
NRC	-	NUCLEAR REGULATORY COMMISSION
NSSS	-	NUCLEAR STEAM SUPPLY SYSTEM
PPM	-	PARTS PER MILLION
PRA	-	PROBABILISTIC RISK ASSESSMENT
PSI	-	POUNDS PER SQUARE INCH
PSIA	-	POUNDS PER SQUARE INCH ABSOLUTE
PT	-	PERIODIC TEST
QA	-	QUALITY ASSURANCE
RCM	-	RELIABILITY CENTERED MAINTENANCE
RCS	-	REACTOR COOLANT SYSTEM
RFO	-	REFUELING OUTAGE
RPS	-	REACTOR PROTECTION SYSTEM
RTB	-	REACTOR TRIP BREAKER
RTBB	-	REACTOR TRIP BYPASS BREAKER
SG	-	STEAM GENERATOR
SI	-	SAFETY INJECTION
SNS	-	STATION NUCLEAR SAFETY
SNSOC	-	STATION NUCLEAR SAFETY AND OPERATING COMMITTEE
SS	-	SHIFT SUPERVISOR
SW	-	SERVICE WATER
TB	-	TURBINE BUILDING
TS	-	TECHNICAL SPECIFICATION
VIO	-	VIOLATION
VPAP	-	VIRGINIA POWER ADMINISTRATIVE PROCEDURE
WO	-	WORK ORDER
WR	-	WORK REQUEST