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

Report Nos.. 50-338/91-22 and 50-339/91-22

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

Docket Nos.: 50-338 and 50-339 License Nos.. NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: September 22 - November 2, 1991

Inspectors: A. Ruff For 11/27/91
M. S. Lesser, Senior Resident Inspector Date Signed

A. Ruff For 11/22/91
D. R. Taylor, Resident Taylor Date Signed

Approved by: MV Sinkule for 11/27/91
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine, inspection by the resident inspectors involved the following areas: operations, maintenance, surveillances, information meeting with local officials, installation and testing of minor modifications, fire protection, fuel pool survey, licensee event report followup, and action on previous inspection findings.

Results:

In the area of operations, one non-cited violation was identified involving inadequate controls associated with activities taken to identify sources of condenser air in-leakage. The Unit 2 air ejector exhaust radiation monitor was inadvertently rendered inoperable and the associated Technical Specification action requirements were not taken (para. 3.b).

In the area of operations, a weakness was identified when the service water system was placed in an unanalyzed condition due to inadequate test procedure. Alertness on the part of an operator to identify the degraded condition resulted in the problem being promptly corrected (para 3.f).

In the area of quality verification, the licensee's identification and followup of a potentially generic issue regarding Garlock rubber expansion joints was considered to be a strength (para 3.c).

In the area of engineering/technical support, a revised engineering evaluation performed in response to the inspectors concerns over inoperable relief valves in the low head safety injection system showed the event to be reportable. The original engineering evaluation was discussed as a weakness in Inspection Report 50-38,339/91-19 (para 3.e).

In the area of surveillance, a weakness was identified when maintenance personnel found a heat trace potentiometer inappropriately rotated to the "off" position. The potentiometer was adjusted, however, no action was taken to report the deviation for further licensee investigation into the cause of the episode (para 5.b).

In the area of safety assessment, the results of tours by management at the plant during backshift hours were reviewed. The licensee's program requires frequent tours by station and corporate management and is considered a strength (para 3.g).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager, Operations and Maintenance
J. Hayes, Superintendent of Operations
D. Heacock, Superintendent, Station Engineer
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
W. Matthews, Superintendent, Maintenance
*F. K. Moore, Vice President Nuclear Engineering Services
D. Roberts, Supervisor, Station Nuclear Safety
D. Schoppell, Superintendent, Site Services
R. Shears, Superintendent, Site Services
*J. Smith, Manager, Quality Assurance
*A. Stafford, Superintendent, Radiological Protection
*J. Stall, Assistant Station Manager, Nuclear Safety and Licensing

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

NRC Resident Inspectors

*M. Lesser, Senior Resident Inspector
D. Taylor, Resident Inspector

*Attended exit interview

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

2. Plant Status

Unit 1 operated the entire inspection period at or about 100 percent power.

Unit 2 started the inspection period at 5 percent power, having recovered from a reactor trip and safety injection on September 20. On September 22, a cooldown to mode 5 was required to repair a packing leak and replace degraded packing gland stud nuts on an RTD bypass mainfold isolation valve. The reactor was re-started on September 26, however, a bushing oil leak on a station service transformer forced the unit off-line for repairs. The unit remained at low power during repair and returned to commercial operation after repairs on September 28. On October 3, power was reduced to 92 percent in order to isolate condenser water boxes and search for condenser tube leaks. The unit operated at 100 percent for the remainder of the inspection period.

3. Operational Safety Verification (71707)

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 operational safety and compliance with TS to maintain awareness of the overall operation of the facility. 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. DR were reviewed to assure that potential safety concerns were properly addressed and reported. Selected reports were followed to ensure that appropriate management attention and corrective action was applied.

a. Condenser Tube Leakage

On October 1, 1991, the licensee detected indications of a Unit 2 main condenser tube leak when chloride concentration in all three steam generators exceeded the specification value of 20 ppb. Administrative Procedure ADM-19.22, Secondary System Chemistry, defines power operation with chloride concentration between 20 - 100 ppb as an Action Level 1 condition. The objective of Action Level 1 is to promptly identify and correct the cause of the out-of-normal value without a power reduction and corrective action is to be completed within one week or enter Action Level 2. Action Level 2 requires a power reduction. The licensee immediately placed the condensate polishers in service and was able to reduce the chloride concentration to less than 20 ppb by October 2. The leak rate was estimated to be 160 gpd. On October 3, Unit 2 power was reduced to 92 percent in order to isolate, one at a time, condenser water boxes and snoop for condenser leaks. The licensee conducted repairs by plugging two tubes and tightening several other plugs that had been previously installed. Power was returned to 100 percent on October 5, and steam generator chemistry parameters remained normal.

b. Inadequate Controls While Conducting Search for Condenser Air In-leakge

On October 6, at 8:00 pm, the licensee discovered the Unit 2 main condenser air ejector exhaust to be isolated from the air ejector exhaust radiation monitor (2-SV-RM-221) and the flow exhausting directly to the turbine building through a normally closed test connection (2-VP-332). This removed the capability of the air ejector radiation monitor as required by TS 3.4.6.4.b to continuously monitor and alarm for a primary to secondary leak and the ability of the exhaust to automatically divert to the containment upon receipt of the alarm. Operators immediately realigned the system for normal operation and reported the event to NRC in accordance with 10 CFR 50.72.

The above problem was discovered while investigating the cause for a lower than expected reading on the radiation monitor. A review of the data showed that the radiation monitor was most probably isolated at 12:45 pm when the radiation monitor readings started to decline. The licensee determined that a loss of administrative control over the system occurred when personnel were involved with efforts to identify sources of condenser air in-leakage. Leak detection equipment had been installed between test connections 2-VP-332 and 2-VP-331. This flow path established a bypass flow around 2-VP-12, which is normally open and supplies flow to the in-line radiation monitor. While checking for sources of condenser air in-leakage, 2-VP-12 is shut to allow flow to pass through the detection equipment. When the evolution was complete, personnel removed the detection equipment without realigning the system. The TS 3.4.6.4.b action for an inoperable radiation monitor requires grab samples at four hour intervals, which were not conducted.

The inspectors reviewed the licensee's methods to control the evolution. Secondary Plant Air In-leakage Inspection Procedure, 2-OP-30.6, which provides a systematic approach for locating the most probable sources of in-leakage, failed to provide instructions for specific valve manipulations to install and remove the leak detection equipment. The licensee initiated a procedure change to include these steps.

The event was attributed to a combination of personnel errors and inadequate procedures. The Shift Supervisor believed the evolution could be performed as skill-of-the-craft, however, supervisory instructions failed to provide personnel directions for installing and removing the equipment. Maintenance personnel also failed to adequately oversee the licensee's contractor, who removed the equipment without informing operations personnel. This appears to be a violation of TS 3.4.5.4.b that requires the ability to continuously monitor air ejector exhaust for primary to secondary leakage, otherwise perform grab samples at four hour intervals. This licensee identified violation is not being cited because criteria specified in section V.G.1 of the NRC Enforcement Policy were satisfied. NCV 50-339/91-22-01

c. Rubber Expansion Joints

The inspectors followed licensee actions taken in response to DR N91-661 in which the Quality Assurance Department identified a concern with the replacement of rubber expansion joints in the SW and Component Cooling Water Systems. The DR indicated that while the UFSAR states that the systems conform to the requirements of ANSI B31.7, rubber expansion joints are not addressed by ANSI B31.7. The licensee response to the DR indicated that rubber expansion joints were originally installed and met the requirements of North Anna Specification NAS-279, Specification for Rubber Expansion Joints 24 Inches and Smaller. Since the subject expansion joints were built to the original construction specification, replacement expansion joints which are equivalent to the original expansion joints, are authorized under ASME Section XI, Article IWA 7000 and are therefore acceptable.

The licensee remained concerned with the fact that the replacement expansion joints were ordered under a later specification (NAP-0022) requiring them to be in accordance with ANSI B31.7, which was certified by the vendor, Garlock. The licensee requested documentation from Garlock showing how the joints conformed to ANSI B31.7. Since rubber is not addressed by the standard, the licensee focused on the metal reinforcement rods embedded within the rubber. The vendor responded to the licensee by letter dated October 8, 1991, which stated that ANSI B31.7 does not apply to the rubber expansion joints and that the expansion joints are built in accordance with the Fluid Sealing Association - Rubber Expansion Joint Division Standards. The licensee concluded that the expansion joints were incorrectly certified to conform with ANSI B31.7. The inspector discussed the issue with the NRC Vendor Inspection Branch who indicated that contact would be made with the vendor in order to pursue the matter for generic concerns.

The licensee performed an engineering evaluation and determined that the expansion joints were acceptable and that the UFSAR needed to be clarified. The inspectors considered the actions of the Quality Assurance department to be thorough and persistent in identifying this issue.

d. Level Instrumentation Out of Tolerance

The inspectors reviewed DR N-91-1608 which concerned out-of-tolerance readings between redundant channels of level instrumentation for Unit 1 "C" SI accumulator. The instrumentation readings for 1-SI-LI-1928 and - 1930 are logged every six hours and are required to be within a 4 percent tolerance of each other. Readings from October 24 at 7:30 am through October 25 at 7:30 am were logged with a 4.5 percent difference. The licensee classified the probable cause as instrument drift and an oversight on the part of the operator to recognize the condition.

The inspectors noted that the hand held micro-computer logger system appeared weak in that the out-of-tolerance readings are not flagged. Further review revealed that the instrumentation readings are not logged consecutively. The operator logs one channel, takes additional logs, and then logs the other channel. A review of the hard copies of the logs indicated that other instrumentation readings which required tolerances between redundant channels were logged in a similar manner.

Operators were interviewed to determine how the tolerance checks are normally performed. The operators indicated that the instrumentation, although on separate control panels, were in close proximity of each other and are normally checked for deviation when the first channel is logged. The operators also indicated that the system would be more user-friendly and instrument tolerances less likely to be overlooked, if the redundant channels were logged together. The licensee subsequently revised the sequence of the logs such that this would occur.

The licensee informed the inspector that during the next update of the micro logger computer system a method would be incorporated to flag out-of-tolerances between redundant channels.

e. Reportability of LHSI Relief Valve Failure

Inspection Report 50-338,339/91-14 and 91-19 discussed the concerns the inspectors had regarding weaknesses in the licensee's operability evaluation associated with LHSI relief valves, which lifted during system testing and failed to reseat. Based on these concerns, the licensee performed a more detailed engineering evaluation (dated September 20, 1991) of the problem and its consequences.

The evaluation reviewed several examples of tests where relief valves lifted and failed to reseat. The cause of relief valve lifting appears to be related to voids in the LHSI system which are initially compressed when a LHSI pump is started with the recirculation line as the flow path. The subsequent pressure spike exceeds the relief setting of 220 psig and the valve lifts. Testing by the licensee showed spikes as high as 380 psig. The evaluation concluded that "the probability of the relief valves lifting is very high and that for proper system operation the blowdown setting of the relief valve is critical."

The licensee evaluated the as-found blowdown ring settings to determine at what pressure the valves would have seated during postulated accident conditions. Seating would occur, depending on the blowdown ring setting, as pump discharge pressure decreases in response to RCS system pressure. In most cases the incorrect settings would not have had any significant safety consequences, however, it was determined that the relief valve would not have seated during a postulated accident for a case when 1-SI-RV-1845A lifted on June 11, 1991, during a test of the system.

For the above case, the licensee determined that a 20 gpm leak of containment sump recirculation water would result, and be discharged to the safeguards building which is outside containment. The UFSAR considers general system leakage into the safeguards building of up to 50 gpm for 10 minutes. The licensee's evaluation stated that the consequences of the event would be equivalent to that analyzed in the UFSAR if the relief valve seated within 25 minutes. It was assumed that this could be achieved by operators either isolating flow or shutting down a LHSI pump.

The inspector voiced concern with these assumptions in that 25 minutes appeared non-conservative and that the proposed operator actions are not covered by procedures. It appeared to the inspector that the event may be reportable under 10 CFR 50.73 as a condition in which a principle safety barrier was seriously degraded for a condition not covered by the licensee's procedures. Following further discussions, the licensee determined the event to be reportable. The inspector will continue to review licensee corrective action to resolve the relief valve lifting problem (the reseating issue appears to have been adequately addressed). The inspectors concluded that the initial operability evaluation was inadequate and caused a delay in reporting this event. Pending review of the licensee's LER, this is identified as URI 50-338/91-22-02, LHSI Relief Valve Inoperability Safety Consequences.

f. Service Water System in Unanalyzed Condition

On October 31, 1991, the licensee was performing Reactor Protection and ESF Logic Test Train B, 2-PT-36.1B, on Unit 2. In order to prevent an automatic start of the 2J EDG and the Unit 1 B-train service water pump 1-SW-PIB, both components were rendered inoperable. The EDG was placed in the "manual local" position and the SW pump was placed in pull-to-lock.

At 11:17 am, the above steps of 2-PT-36.1B were completed. At this point one of the Senior Reactor Operators questioned the lineup believing that operation with only 2 of the 4 shared service water pumps operable in conjunction with service water to the CCHX's unthrottled represented an unanalyzed condition. This was discussed with licensee management and the 2J EDG was placed in "automatic remote" at 11:43 am, alleviating the concern.

The licensee reviewed the event for reportability and initially determined the condition to be acceptable. However, after concerns from the inspectors were discussed, the licensee properly reported the event at 3:10 pm.

As reported to the NRC in previous LERs 338/88-24 and 338/90-12, a design basis accident in which only 2 of 4 SW pumps operate would result in less than design flow rates to the RSHX's. To compensate for this, and ensure adequate flows are supplied to the accident unit's RSHXs, SW flow to the non-accident unit must be maintained through only 1 CCHX or in a throttled condition to 2 CCHXs.

A Notice of Violation (50-338,339/90-29-01) was issued on February 1, 1991 when the licensee failed to apply the requirements of TS 3.0.5 to the system when a unit in mode 5 or 6 has an inoperable EDG. In that case the respective SW pump was incorrectly considered operable for purposes of providing flow to the opposite unit at power.

The licensee implemented administrative restrictions by issuing Standing Order 177 for which requirements existed if three SW pumps were operable. These were: (1) consider the plant to be in the 72 hour LCO action requirement of TS 3.7.4.1.a whereby a single failure would not have to be considered and three SW pumps would be adequate, or (2) throttle all CCHX outlet valves such that SW pump discharge pressure is no less than 58 psig, thus ensuring that in the event of a single failure of a SW pump, two would be adequate to supply accident loads. Standing order 177 was later cancelled when the requirements were incorporated into various operating procedures.

It appears that the event of October 31, 1991, resulted from an inadequate test procedure and the misapplication of TS 3.0.5 which states that a component does not have to be considered inoperable solely because its emergency power source is inoperable provided all redundant components are operable. In this case with the 2J EDG inoperable, 2-SW-P1B did not have to be considered inoperable until one of its redundant pumps 1-SW-P1B was placed in pull-to-lock. After the condition was established, the operator recognized that the situation may be outside the design basis and corrective action was taken in about 26 minutes. Alertness on his part resulted in the situation being promptly resolved and the safety significance reduced. The licensee reviewed all cases within the year when this test was conducted and identified three additional examples where this SW pump lineup occurred. Review of operating logs showed that during these tests, SW pump discharge pressure was at least 58 psig and therefore acceptable. The inspectors considered that action taken in response to violation 50-338,339/90-29-01 was, in part, ineffective in that test procedures were not reviewed to ensure the SW system remained within the design basis of the plant. The licensee was requested to provide a supplemental response to the previous violation addressing this event and action taken and planned in order to prevent recurrence.

g. Management Backshift Tours

The inspector reviewed the results of several assessments conducted by corporate managers who performed backshift hours. The site's policy requires a tour by a corporate manager on a monthly basis and typically includes observation of shift turnover, log review, board walkdown, maintenance observation and discussions with operators. The assessments contained details of potential problem areas observed including equipment in need of attention, and suggestions for improved work practices in addition to good practices.

One non-cited violation was identified in paragraph 3.b.

4. Maintenance Observation (62703)

Station maintenance activities were observed/reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TS requirements.

a. EDG Annual Preventive Maintenance

On October 2, the inspector observed various annual maintenance activities on the 2J EDG. The mechanical maintenance procedures for Diesel Generators, MMP-P-EG-1, was used to inspect and clean lube oil and fuel oil filters, inspect the fuel racks and injection pumps, inspect air filters, and measure clearances between the scavenging blower lobe and housing. Additionally, the engine coolant was changed out for winterization. During the post maintenance operability run, a minor jacket water coolant leak was identified. The licensee shut the EDG down and took action to repair the leak.

b. Failure of 2-QS-MOV-202A Motor

On October 18, during MOV testing of the Chemical Additional Tank Supply Valve to RWST, 2-QS-MOV-202A, it was determined that the torque switch settings should be raised to increase thrust valves. Subsequent testing resulted in the motor overheating. The pursuing investigation did not trip because corrosion prevented movement of the spring pack. This resulted in locked rotor amps and subsequent over heating. The MOV is located outside and the corrosion of the spring pack apparently resulted from moisture intrusion. A check was performed of other MOVs subject to the same environmental conditions which revealed no similar corrosion problems. The inspector was informed that the test procedure was revised to require motor amp readings when testing the valves.

c. Repair of Pressurizer Pressure Master Controller

The inspectors observed the trouble shooting and repair for the pressurizer pressure master controller. All of the pressurizers back up heaters were coming on with the controller output stable at 40 percent. This caused annunciator 1B H-6 to be activated. The inspectors observed the I & C technicians using a recorder to detect a spike on the output control card. This driver card (No. C8-130) was replaced and the master controller was placed back in service but the heaters came on and the annunciator was reilluminated. The technicians then replaced the comparator card and after calibration and system check out, the system was returned to service. The technicians used procedure 1CP-RC-1-P-1444, Pressurizer Pressure Control, and work order No. 77818 to accomplish the work. No deficiencies were noted by the inspectors during this maintenance activity.

No violations or deviations were identified.

5. Surveillance Observation (61726)

The inspectors observed/reviewed TS required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met and that any deficiencies identified were properly reviewed and resolved.

a. EDG Day Tank Level Switch Calibration

On October 9, the inspector witnessed calibration of the 1H Diesel Generator Day Tank High Level Instrument (1-EG-LS-103HB), which was performed using ICP-P-1-M1-I, Instrument Calibration Procedure for Miscellaneous Instruments. The procedure is a generic procedure requiring the acceptance criteria for the high level function to be obtained from the setpoint document (7.75 inches from the top of the tank). The technicians must convert this number to the actual height of fuel oil above the pressure sensor using measured distances from the bottom of the tank and the specific gravity of fuel oil. The calculation appeared burdensome and the technicians used the numbers obtained from a previous calibration. The inspector verified that the measurements and calculations were correct. From discussions with the technicians, the inspector ascertained that the isolation valve for the pressure switch was found closed instead of the required open position. The technicians appropriately documented the condition in a DR. The pressure switch is a redundant high level trip for the backup fuel oil transfer pump to prevent the day tank from overflowing.

The inspector identified that the high level pressure switch (1-EG-LS-103HA) for the lead fuel oil transfer pump was incorrectly labelled as a low level switch and determined that this was the case on three of the four EDG day tanks. These switches had recently been re-labeled as part of the licensee's new labelling program. The licensee initiated a DR to correct the error.

b. Heat Trace Testing

The inspector witnessed surveillance activities on portions of the heat trace system on October 1, 1991. Procedure 0-EPM-1303-03, Setpoint Verification of Heat Tracing Circuits Controlled From Cabinets EP-CB-13N and R, was used to test the system. The procedure requires the technicians to check each heater circuit for operability by measuring the circuit output voltage, the high/low temperature alarm setpoints and the heater on/off setpoints. The majority of the checks witnessed by the inspector resulted in as-found setpoints outside of the acceptance criteria. The procedure does not require these values to be recorded. Step 6.2.3.a allows the technician to adjust the applicable potentiometer as necessary to obtain the expected values.

The inspector raised concerns regarding a potential drifting problem with the heat trace circuits and the lack of procedural requirements to record and access setpoints which are found out of specification. This particular procedure is an upgraded procedure which became effective June 4, 1991. In that as-found data is not recorded, it becomes difficult to determine a drifting problem with the circuit. The licensee responded by pointing out that high and low temperature alarms exist on the circuits to alert operators to adverse situations.

One particular heat trace circuit 1-HT-ET-85 was found with its potentiometer set to 0°F. The nominal setting is approximately 150°F. Since the potentiometers are on the outside of the cabinet, the inspector was concerned that it may have been tampered with. The technicians adjusted the circuit to the correct value, however, they did not take action to initiate a DR. This appeared to be inconsistent with VPAP 1505, Station Deviation Reports, which requires the initiation of a DR for deficiencies or adverse conditions identified during the performance of maintenance procedures and calibrations. The inspector determined that this particular circuit was not required to be operable by Technical Specifications. The concerns remain valid for those circuits that are required by Technical Specifications.

The inspector reviewed JCO 88-19 which was developed to downgrade certain applications of heat tracing from safety related to non-safety related. The applications involved heat tracing on the Boron Injection Tank and the Boric Acid Storage Tanks. The JCO referenced IEEE Standard 662-1979, Recommended Practice for the Design and Installation of Electric Pipe Heating Systems for Nuclear Power Generating Stations, which indicated that heat tracing on reactor injection piping does not perform any safety functions during or after a postulated LOCA and thus is not required in a post-accident situation. The JCO stated that the systems play an important role in the normal operation of the station, therefore, redundancy and reliable power sources are required although not necessarily class 1E power systems. The JCO, however, did not discuss the consequences of a heat trace failure during normal operations. It appeared to the inspector that methods available to detect a failure, surveillance and alarms are adequate. Technical Specifications require plant shutdown if both redundant circuits are inoperable.

c. Normally Deenergized Power Circuits

The inspector conducted a walkdown of circuit breakers required to be deenergized while in modes 1, 2, 3 and 4. For these modes, TS 3.8.2.7 requires certain circuit breakers that are not required during reactor operation to be de-energized in order to protect the containment penetration. Loop Stop Valve and Containment Equipment Breaker Position Verification, 2-PT-42.1, was checked against the TS and used to conduct the walkdown. One circuit breaker for refueling and maintenance power was listed in the PT as breaker 24C2-16 and labelled as such, however, the TS listed it as breaker 2HN-16.

The inspector discussed the discrepancy with the licensee and verified through review of drawings that the correct breaker was de-energized. The licensee determined that the breaker was correctly labelled and identified in the PT, however, could not explain the device number and location as listed in the TS. It appeared to be an error with the TS and the licensee stated that they would take action to correct it.

d. 2J Diesel Run

On October 30, the inspectors observed the performance of 2-PT-82J, 2J Emergency Diesel Generator Slow Start Test. The test verifies the operability of the 2J EDG, its associated fuel transfer pumps and air start flow path. The procedure requires local starting of the diesel and subsequent return of control to the control room where the diesel is loaded and run for at least one hour.

The inspectors noted that with the diesel running the local lube oil level low annunciator was lit. The licensee informed the inspectors that for the 2J Diesel the annunciator normally alarms when the diesel starts but would go out after the lube oil was warmed. After the one-hour run, but prior to shutting down the diesel, the annunciator was still lit. Dip stick oil level indicated above the add level. The licensee's maintenance department was informed. No other concerns were noted.

6. Installation and Testing of Minor Modifications (37828)

The inspectors observed piping modification activities associated with the instrument air compressors under DCP 89-04. Following installation and testing of new instrument air compressors in 1989, the licensee identified an excessive pressure drop between the air receiver and the dryer. Field Change 49 was implemented to replace the two inch carbon steel piping and piston type check valve with a three inch stainless steel pipe and swing check. The inspector reviewed the flame permit and observed proper work practices including foreign material exclusion, fire watch and safety precautions. Personnel appeared knowledgeable of their duties.

7. Fire Protection (62704)

The inspectors assessed the adequacy of the licensee's backshift staffing of operations personnel when the fire brigade is required. The minimum number of personnel required on any given shift is governed by licensee administrative procedures and Technical Specifications. The licensee's Technical Specifications requires a minimum shift crew during power operations of ten including, 2 SROs, 3 ROs, 4 non-licensed operators and 1 STA. Additionally, VPAP 1401 "Conduct of Operations" requires a Fire brigade of at least five members, three of which are operations personnel. VPAP 1401 also requires that the fire brigade not include personnel from the operations department minimum shift team composition or personnel necessary for required essential functions or the safe shutdown of the station during a fire.

North Anna's worst case fire scenario as described in the Appendix R review assumes a minimum shift crew of eight to operate safe shutdown equipment. The fire brigade is independent of the minimum crew and is controlled by administrative procedures.

The inspectors verified the shift composition was in compliance with Technical Specifications and administrative procedures. For all shifts verified by the inspectors, the licensee exceeded staffing requirements. One concern identified by the inspectors as a result of reviewing, was the assignment of personnel to specific watches concurrently with other duties. No controls or requirements were in place to prevent collateral duties that could interfere with essential functions and fire brigade assignment. On one occasion the inspectors noted that the Shift Supervisor's log had an auxiliary operator assigned simultaneously as a fire brigade member and NRC communicator. The inspectors questioned the assignment and were informed that the assignments were changed at shift turnover and that the log would be updated. The inspectors concluded that adequate staffing is available for maintaining or placing the plant in a safe condition concurrent with a fire.

8. Fuel Pool Survey (86700)

The inspectors conducted a review of the licensee's controls of material stored in the spent fuel pool. The review was prompted by problems identified at other facilities with regards to storage and inventory of material in the pool. The inspector determined that North Anna does not have an administrative program which prevents or controls the material stored in the spent fuel pool, however, a review of material currently in the pool did not identify any concerns.

The inspectors reviewed the most recent performance of 1-OP-4.21, Operations Special Nuclear Material Physical Inventory. The procedure performs a piece count of all fuel assemblies and fuel rod cans within the new fuel area and spent fuel pool. Additionally, 60 randomly selected fuel assemblies are checked to verify proper location. No inventory is performed of other materials. Most of the non-fuel materials are stored in a fuel rack and are tracked to show that the particular location within the pool is no longer available for fuel storage.

9. Information Meeting with Local Officials (94600)

On September 26, 1991, the inspector met with local officials from Hanover County. The inspector discussed various aspects of the NRC including principle roles, legal basis, organization, inspection activities, and location of the Public Document Room. Selected handouts from the NRC 1991 Information Digest were passed out along with NRC telephone numbers.

10. LER Followup (92700)

The following LER was reviewed and closed. The inspector verified that reporting requirements had been met, that causes had been identified, that corrective actions appeared appropriate and that generic applicability had been considered. Additionally, the inspectors confirmed that no unreviewed safety questions were involved and that violations of regulations or TS conditions had been identified.

(Closed) LER 338,339/91-14, Failure to Measure the Inlet Pressure for Boric Acid Transfer Pump Surveillance Tests.

An event on July 3, 1991, was reported in the subject LER that states an ASME Section XI surveillance requirement for the BATPs had not been adequately performed during the second quarter of 1991. The Licensee's IST Program requires that the BATP inlet pressure be directly measured after April 1991. However, because problems were encountered with permanent BATP inlet pressure gages, the inlet pressure to the pumps was determined by calculation using the BA tank level. The test, using direct reading pressure gages, was performed satisfactorily on July 5 and 6. The events concerning this item are discussed in NRC Report 50-338,339/91-14 and it is one of four examples cited in violation 50-338,339/91-10-03, Failure to Meet Surveillance Requirements of the IST Program. The inspectors will continue to assess the corrective action for the violation.

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

a. (Closed) IFI 338/90-25-02, Improved Monitoring of Control Room chillers.

   Because of numerous instances of control room chiller problems and automatic tripping of the control room chiller units, the inspectors considered this to be an item of concern and expressed these concerns with the station management. It was considered that if additional attention could be focused on these chiller units, it may preclude or nearly eliminate chiller trips and problems. The licensee was in the process of focusing more attention on this problem and recently implemented the following to enhance the reliability of these control room chiller and reduce the chillers' automatic trips:

   1) The compressor pressure gages (discharge, suction, and oil pressure) have been replaced with types that can better withstand the vibrational and pressure transients associated with chiller normal operations. These new gages can remain on line and in service for normal operations.

   2) Daily readings (with acceptance criteria specified) on compressor pressure gages (discharge, suction, and oil pressure) are being taken for predictive analysis and trending purposes.

3) The pressure gages in 1) above have been calibrated and will be placed in a PM program that calls for their periodic calibration.

4) Flow switches and pressure controllers for the chillers have been placed in a PM program that calls for their periodic calibration.

b. (Closed) Violation 50-338,339/91-06-01: Ineffective Corrective Action to Prevent Recurrence of Adverse WGDT Conditions.

The violation involved the failure of licensee actions to correct potentially explosive gas situations in the WGDT within required time frames. The licensee responded to the violation in correspondence dated May 10, 1991. Corrective action included an operations procedure revision, an operations departmental memorandum discussing the event and a TS amendment on explosive gas mixtures. The amendment provides improved guidance for actions to take during adverse conditions and was approved September 25.

12. Exit (30703)

The inspection scope and findings were summarized on November 6, 1991, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
NCV 50-339/91-22-01	Inadequate Controls While Checking for Condenser Air In-Leakage Resulting In An Inoperable Radiation Monitor (para 3.b)
URI 50-338/91-22-02	LHSI Relief Valve Inoperability Safety Consequences (para 3.e)

13. Acronyms and Initialisms

ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
BA	Boric Acid
BATP	Boric Acid Transfer Pumps
CCHX	Component Cooling Heat Exchanger
CFR	Code of Federal Regulations
DCP	Design Change Package
DR	Deviation Report
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator

ESF	Engineered Safety Feature
GPD	Gallons per Day
GPM	Gallons Per Minute
IEEE	Institute of Electrical and Electronics Engineers
IFI	Inspector Followup Item
IST	In-Service Test
JCO	Justification for Continued Operations
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHSI	Low Head Safety Injection
LOCA	Loss of Coolant Accident
MOV	Motor Operated Valve
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
PM	Preventive Maintenance
PPB	Parts per Billion
PSIG	Pounds per Square Inch Gage
PT	Periodic Test
RCS	Reactor Coolant System
RO	Reactor Operator
RSHX	Recirculation Spray Heat Exchanger
RTD	Resistance Temperature Detector
RWST	Refueling Water Storage Tank
SI	Safety Injection
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
SW	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Violation
VPAP	Virginia Power Administrative Procedure
WGDT	Waste Gas Decay Tank