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

Report Nos.: 50-338/89-08 and 50-339/89-08

Licensee: Virginia Electric & Power Company
Richmond, VA 23261

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

Facility Name: North Anna 1 and 2

Inspection Conducted: March 21 through April 17, 1989 and April 25 through May 3, 1989.

Inspectors: M. S. Lewis for 5/17/89
J. L. Caldwell, Senior Resident Inspector Date Signed

M. S. Lewis for 5/17/89
L. P. King, Resident Inspector Date Signed

M. S. Lewis for 5/17/89
J. Munro, Resident Inspector Date Signed

Accompanying Personnel: N. Economos
M. S. Lewis
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Approved by: 5/17/89
P. E. Fredrickson, Acting Branch Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine inspection involved the following areas: plant status, maintenance, surveillance, operational safety verification, operating reactor events, licensee event report followup, review of inspector follow-up items, Generic Letter 88-17, refueling activities, and EDG fuel oil storage and handling. During the performance of this inspection, the resident inspectors conducted reviews of the licensee's backshift operations on the following days: March 27, 30, 31, April 3, 5, 6, 10, 12, and 17, 1989.

Results: Within the areas inspected, there were two violations and two apparent violations identified:

Violation: Failure to have adequate maintenance procedures to ensure proper operation of ESF equipment 480 volt ITE breakers (paragraph 8).

Violation: Failure to comply with TS 4.6.1.1.a.1 for containment penetration vent and drain valves (paragraph 8).

Apparent Violation: Potential for the SW and RSHXs to have been inoperable (paragraph 4.b).

Apparent Violation: Inadvertent loss of reactor vessel level (paragraph 6.d).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Bowling, Assistant Station Manager
J. Downs, Superintendent, Administrative Services
*R. Driscoll, Quality Control Manager
*L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager
*G. Flowers, Configuration Management Supervisor
*M. Garton, Instrument Supervisor
G. Gordon, Electrical Supervisor
D. Heacock, Superintendent, Engineering
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
*J. Leberstein, Licensing Engineer
*W. Matthews, Superintendent, Maintenance
T. Porter, Superintendent, Engineering
*J. Stall, Superintendent, Operations
*A. Stafford, Superintendent, Health Physics
F. Terminella, Quality Assurance Supervisor
D. Thomas, Mechanical Maintenance Supervisor

Other licensee employees contacted during this inspection included engineers, technicians, operators, mechanics, security force members, and administrative personnel.

*Attended exit interview

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

2. Plant Status

On March 21, the beginning of the inspection period, Unit 1 was in Mode 5, day 24 of an outage, which commenced with the C steam generator tube leak event on February 25. On March 23, Unit 1 experienced a loss of the 1H emergency bus while performing tests of the EDG. The de-energization of the 1H bus resulted in the tripping of the operable RHR pump (1A). The unit was not in a reduced RCS inventory (pressurizer level at the time was approximately 5 percent) and the 1B RHR pump was started within 60 seconds of the 1A RHR pump trip (see paragraph 4.a for details). On April 14, the licensee conducted a SW flow balance test on the RSHXs. The results of the test indicated potential inoperability of the SW/RS systems (see paragraph 4.b for details). On April 16, Unit 1 experienced another loss of the operating 1A RHR pump. The unit had approximately 5 percent level in the pressurizer and the operators started the 1B RHR pump in approxi-

mately 6 minutes. The cause of the loss of an RHR pump was a fault in the switchyard caused by a personnel error (see paragraph 6.c for details).

On March 21, Unit 2 was defueled, day 30 of the refueling outage. The fuel reload commenced on March 26 and completed on March 28. On April 3, Unit 2 experienced a loss of CCW to the operating RHR heat exchanger. The unit was drained to approximately 5 inches below the vessel flange at the time and therefore not in a reduced RCS inventory condition. The operators restored CCW flow in approximately 25 minutes (see paragraph 6.b for details). On April 5, the reactor vessel head installation was completed and Unit 2 entered Mode 5.

On April 13, the Chairman of the Czechoslovakian Atomic Energy Commission and six of his associates visited the North Anna Power Station at the invitation of the licensee. The chairman and his group were given a presentation and a tour of the station and associated facilities by the licensee. The inspector briefly met with the Czechoslovakia personnel while they were touring the simulator in the training building.

3. Maintenance (62703)

Station maintenance activities affecting safety-related systems and components 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 Technical Specifications. The following details the inspector's findings/concerns.

a. ASCO SOV Failure Root Cause

NRC Inspection Report 338,339/88-02 identified concerns relating to the failure of air operated containment isolation valves. These failures were attributed to problems with the ASCO SOV not performing properly. As a result of these concerns, the licensee committed to perform a failure analysis of the ASCO SOVs. The need for this analysis was further highlighted in Inspection Report 338,339/88-36, which identified concerns relating to instrument air water and oil contamination problems that may have been the cause or at least contributed to the cause of the ASCO SOV failures. The inspector obtained a copy of the licensee's failure analysis report and the following is a brief summary of the report and its conclusions.

(1) The cause of increased containment isolation valve stroke times was due to the installation of improperly sized tubing on the exhaust portion of the SOVs. Valve stroke times have been consistent since the replacement of smaller exhaust tubing with larger tubing. There are seven SOVs still requiring exhaust tube replacement. The licensee plans to replace the tubing prior to the startup from the present refueling outages.

(2) Several SOVs (ASCO model NPX8321A1E) were found stuck in mid position. Their failure can be attributed to the combination of the water intrusion into the instrument air system, and mixing of the particulate contamination with assembly lubricants. Consequently, the licensee concluded that ASCO NPX8321A1E SOVs appear to be susceptible to particulat contamination from the instrument air system.

(3) Inspections were made on two SOVs (ASCO model KX206-380-3U) which failed to operate once deenergized. In one case, the likely failure mechanism was the adhesion between the core/spring and solenoid sub-assemblies caused by oxidized silicone lubricant deposits. In the other case, the root cause is inconclusive; however, a similar failure mechanism is suspected. The licensee concluded that ASCO model KX206-380-3U SOVs that are energized for prolonged periods may be susceptible to the failure mechanism described above.

The licensee determined that the number of SOVs (model KX206-380-3U) which have failed to stroke since February 1988, has been minimal. The two cases that have occurred were inspected as discussed above. Paragraph 5.c of this report contains an additional example of a SOV failure. The licensee's engineering group feels this is an insufficient number to definitely determine the root cause of ASCO SOV failures.

The licensee initiated EWR 89-166 to replace all SOV Model NPX 8321A1E during the refueling outage. Once this modification is complete, the model of ASCO SOV used on the inside air operated containment isolation valves will be different than those used on the outside containment isolation valves for the same mechanical piping penetration, except for the charging system trip valves. This will help prevent common mode failures on a single penetration. The ISI program has been revised to increase the frequency of stroke time tests for many safety-related trip valves, exceeding ASCO's recommendation in this area. Also, the quality of instrument air has improved with modifications to the instrument air system. These factors should increase the reliability of safety-related trip valves whose pilot valve is an ASCO SOV.

b. LHSI Pump Maintenance

On April 10, the inspector witnessed portions of the overhaul of the Unit 2 LHSI pump (2-SI-P-1A) per MMP-C-SI-1, Low Head Safety Injection Pump Inspection, Repair and Seal Replacement. The inspector observed the installation and torquing of the last two columns on the pump shaft and the installation of one of the wedges between the pump casing and the pump columns. No problems were observed by the inspector.

c. Unit 2 Steam Generator Outage Work

During the present Unit 2 refueling outage, the licensee conducted numerous inspections and maintenance activities concerning the steam generators. The following is a list of the activities and the results:

(1) Steam generator eddy current testing was conducted on the tubes of all three steam generators. All of the tubes were inspected through the U-bend, except for several short U-bend radius Row 2 tubes, using the standard bobbin probe (both hot and cold legs). In addition to the bobbin probe, the tubes in rows 8 through 12 were inspected to the seventh support plate using the 8 x 1 pancake probe (both hot and cold legs), and all other rows were inspected on the hot leg side through the first support plate using the 8 x 1 pancake probe. Any indication discovered by one of the above methods was verified by the RPC probe. Also, 25 row 2 tube U-bends were inspected using the RPC probe. As a result of the above inspection, four tubes in the A steam generator, 10 tubes in the B steam generator and 15 tubes in the C steam generator are required to be plugged.

(2) Steam generator sludge lancing was conducted on all three steam generators to remove sludge that had collected on the tubes and tube sheet. The results of the lancing involved the removal of 288 pounds of material from the A steam generator, 312 pounds from the B steam generator, and 226 pounds from the C steam generator. This is comparable to the amount of that was removed from the Unit 2 steam generators during the 1987 refueling outage, which ranged from 230 to 270 pounds.

(3) As a result of the failed plug that caused a steam generator tube leak event on the Unit 1 reactor in February of this year, the licensee replaced several plugs in the Unit 2 steam generators. The licensee determined that 13 hot leg plugs in the A steam generator, 10 in the B steam generator, and 30 in the C steam generator would have to be replaced because they had been determined to be susceptible to the same type of failure that occurred in the Unit 1 C steam generator. Refer to paragraph 6.d of this report for further details on the tube plug concern.

(4) The Unit 2 B steam generator J-tubes were inspected and determined to be acceptable. The licensee had replaced the Unit 2 carbon steel J-tubes with inconel J-tubes in all three steam generators during the 1985 outage. Since the inspection was satisfactory in the B steam generator, the other two steam generators were not required to be inspected.

No violations or deviations were identified.

4. Surveillance (61726)

The inspectors observed/reviewed technical specification required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that limiting conditions for operation were met, and that any deficiencies identified were properly reviewed and resolved.

a. Loss of 1H Emergency Bus and 1A RHR Pump

On March 23, during the performance of 1-PT-82.3A, 1H Diesel Generator Test (Simulated Loss of Offsite Power in Conjunction with ESF Actuation Signal), the licensee inadvertently lost power to the 1H emergency bus. The surveillance was intended to test the fast start capability of the 1H EDG using a simulated safety injection and 90 percent degraded voltage signal. At the time of the surveillance, Unit 1 was in Mode 5 with an RCS temperature of 102°F. Pressurizer level was approximately 5 percent, the 1A RHR pump was operating and the 1H emergency bus was being supplied by the alternate power source through breaker 15H1. When the operator commenced the test, the breaker upsteam of 15H1 (15B11) opened, causing 15H1 to also open and de-energize the 1H emergency bus. As a result of the loss of the bus, the operating 1A RHR pump, which is powered by the 1H bus, also tripped. An operator stationed at the RHR pump controls immediately started the 1B RHR pump, resulting in a negligible change in RCS temperature. The 1H EDG auto-started and loaded onto the bus in less than 10 seconds as required. The 1H EDG was subsequently paralleled to the alternate power supply and the 1H bus was returned to normal. The EDG was secured in approximately 15 minutes.

The inspector reviewed the procedure 1-PT-82.3A and, as stated by the licensee, there were no initial conditions or precautions requiring the emergency bus to be powered by the normal power supply. Even though the procedure was inadequate in not requiring that the bus be powered by the normal breaker 15H11, the operators stopped the test on March 23 to determine if it was acceptable to continue with the bus being powered from the alternate power supply. The Control Operations Department was contacted and requested to determine if the test switch would block the 15H1 breaker from tripping as it normally does for the 15H11. The operators were informed that the 15H1 breaker would not trip; however, the Control Operations personnel failed to check the upstream breaker 15B11, which was not blocked and did trip on the simulated 90 percent degraded voltage signal.

The operations staff did an excellent job in stopping the test and questioning the abnormal alignment. However, since the test procedure did not have a requirement for the emergency bus to be powered from the normal power supply, no formal change was required to proceed in the abnormal alignment. The review conducted by the Control Operations Department was informal and incomplete. This informal review resulted in the failure of the Control Operations personnel to identify that breaker 15B11 was not blocked by the test switch and would trip.

The licensee has initiated corrective action, which involves placing in all applicable surveillance tests, deviations that prevent the test from being performed in an abnormal electrical alignment. The inspector has verified that a procedure deviation does exist in the front of the control room copies of the following surveillance tests; 82.2A, 82.2B, 82.3A, 82.3B, 82.4A, and 82.4B. The licensee has committed to establishing a formalized approach for obtaining Control Operations assistance, including a method of permanently capturing and utilizing the information obtained. This approach will be developed and a schedule established for its implementation by May 17, 1989.

b. Service Water to RSHXs Flow Balance

On April 4, the inspector received a briefing on 1-PT-75.6, Service Water System Flow Balance, prior to performance of the test. This procedure was developed to allow for full flow testing of the SW system through the RSHXs. The results of the procedure were designed to allow the licensee to determine if the design basis flow would actually be achieved through the RSHXs and provide data on the maximum flow which could be allowed through the CCW heat exchangers during normal operations.

Concerns regarding the ability of the RSHXs to perform their intended safety function were raised in NRC Inspection Report 338,339/88-11. These concerns involved potential increased fouling factor associated with the RSHXs and the resultant reduction in their heat transfer capabilities. However, during the discussion concerning the increased fouling of the RSHXs, it was assumed that the heat exchangers would receive their design SW flow.

Also, as documented in NRC Inspection Report 338,339/88-31, the licensee identified a potential problem associated with SW flow through the CCW heat exchangers. This concern involved SW pump and CCW heat exchanger flow combinations which could prevent achieving the required SW through the RSHXs during an accident. An additional complication involved the assumption that the SW pumps would deliver a flow of 15,000 gpm per pump. This concern was identified as IFI 338,339/88-31-04, pending the SW flow testing that is being conducted this outage.

The licensee conducted 1-PT-75.6 for the Unit 1 RSHXs on April 14. The test performed head curve verifications on all four SW pumps and indicated that the maximum flow rate for the pumps was actually approximately 13,500 gpm instead of the 15,000 gpm that was expected by the licensee. The results of the test also indicated that the SW flow through two of the four RSHXs was below the required design flow of 4500 gpm, as stated in the UFSAR, Table 6.2-2. The SW as-found flow results are as follows:

A RSHX - 5020 gpm
B RSHX - 4850 gpm
C RSHX - 3740 gpm
D RSHX - 2650 gpm

The SW flow through the RSHXs is controlled by a throttle valve for each heat exchanger (1-SW-103 A, B, C and D). The licensee was able to adjust these valves to achieve the following as-left SW flow results:

A RSHX - 4610 gpm
B RSHX - 4610 gpm
C RSHX - 4570 gpm
D RSHX - 4660 gpm

Based on the discovery of the SW flow below the required flow of 4500 gpm in two of the RSHXs, the licensee notified the inspector of their findings and will follow up this notification with an LER in 30 days.

The inspectors were able to determine that the last time the throttle valves (103 A, B, C and D) were flow tested and adjusted was in 1981. Since that adjustment, major modifications have been made to the SW system, including the overhaul of the SW pumps, mechanical and chemical cleaning of the SW piping and installation of new SW return headers with newly installed spray arrays and associated valves. As a result of these modifications and maintenance, the licensee conducted post modification testing but did not include the re-verification of the SW flow through the RSHXs (i.e., the throttle settings of the 103 and 203 valves). It is unclear whether the improper throttle settings and resulting low SW flow rates were a result of the modifications or of initially not being adjusted properly. If adequate post maintenance testing had been conducted, the licensee would had identified the RSHX SW flow rate discrepancies earlier.

The combination of the questionable SW pump and CCW heat exchanger configurations (see IR 338,339/88-33), and the identification of two of the RSHXs having SW flow rates below design bring into question the past operability of the Unit 1 SW and recirculation spray systems. This item will be identified as an apparent violation 338,339/89-08-03.

The test also demonstrated that the installed SW flow instrumentation was not accurate. To ensure that the test flow data was accurate, the licensee used temporarily installed ultrasonic flow instrumentation and differential pressure instrumentation installed across each heat exchanger. The differential pressure instruments agreed with the ultrasonic flow instrumentation for changes in the SW flow during the throttle valve adjustments. This helped confirm the accuracy of the ultrasonic instrumentation.

The licensee also determined, based on the SW pump head curves, the maximum SW flow rate which could be allowed through the Unit 2 CCW heat exchanger during normal operation and still meet the design flow through the Unit 1 RSHXs during accident conditions. This determination was made by adjusting the Unit 2 CCW heat exchanger SW flow to the maximum achievable with SW flowing through the Unit 1 RSHXs at their design flow of greater than 4500 gpm each. Then the SW flow through the RSHXs was secured and the resulting flow through the Unit 2 CCW heat exchanger was determined based on the SW pump discharge pressure and head curve. This flow rate, as determined by the SW pump discharge pressure, was 10,800 gpm. The installed flow instrumentation indicated approximately 12,500 gpm return header flow and approximately 14,500 gpm supply header flow, demonstrating the installed flow instrumentation inaccuracies.

5. Operational Safety Verification (71707)

By observations during the inspection period, the inspectors verified that the control room manning requirements were being met. In addition, the inspectors observed shift turnover to verify that continuity of system status was maintained. The inspectors periodically questioned shift personnel relative to their awareness of plant conditions. Through log review and plant tours, the inspectors verified compliance with selected TS and Limiting Conditions for Operations.

In the course of the monthly activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls; searching of personnel, packages and vehicles; badge issuance and retrieval; escorting of visitors; patrols; and compensatory posts. On a regular basis, RWPs were reviewed and the specific work activity was monitored to assure that the activities were being conducted per the RWPs.

The inspectors kept informed, on a daily basis, of overall status of both units and of any significant safety matter related to plant operations. Discussions were held with plant management and various members of the operations staff on a regular basis. Selected portions of operating logs and data sheets were reviewed daily. The inspectors conducted various plant tours and made frequent visits to the control room. Observations included: witnessing work activities in progress; verifying the status of operating and standby safety systems and equipment; confirming valve positions, instrument and recorder readings, and annunciator alarms; and observing housekeeping.

a. Tornado Watch

On March 31, the licensee was notified that the area in which the North Anna station is located was under a tornado watch. The control room operators entered AP-41.1, Severe Weather Conditions, and took

the necessary actions associated with the tornado watch. The inspector reviewed the AP, conducted a tour of the station grounds and randomly selected portions of the abnormal procedure action requirements to be verified. The inspector determined, based on observations, that the licensee was in compliance with the AP. A severe weather condition did not develop in the area of the plant.

b. Tour of High Radiation Areas

On April 12, the inspector made a tour of the following high radiation areas with the Superintendent of Health Physics.

(1) The B gas stripper room (lower level).

No problems noted.

(2) The A gas stripper room (lower level).

The inspector observed the following:

(a) A leak downstream of a shut capped drain valve on a heat exchanger.

(b) A broken stem off of air operated valve 1BR-P-10B.

(c) A loose ground strap on gas stripper discharge pump 1-BR-P-7B.

(d) Excessive boron on the gland of gas stripper discharge pump 1-BR-P-7B.

(e) A leaky gland on the suction valve to gas stripper circulating pump 1-BR-P-10B.

The inspector informed the Superintendent of Operations of the above findings. The Operations Superintendent stated that an operator would be sent to these areas to document the problems and ensure that a maintenance work request was written on each item.

(3) Primary plant demineralizer valve alley.

This area was generally clean, with the exception of two bags of trash.

(4) Unit 2 seal injection filter area.

Health Physics had stopped work in this area due to housekeeping problems. There was evidence that valve repacking had been in progress. The gasket for the 4A filter head showed signs of leaking.

The inspectors will conduct followup tours of these areas to determine if the maintenance items are being corrected and if housekeeping has improved.

c. Equipment Failures During February 25, 1989, Unit 1 Reactor Trip and Cooldown to Mode 5.

The licensee has identified two valves in the list of equipment which malfunctioned during the S/G "C" tube leak and subsequent cooldown to Mode 5 of Unit 1. The identification of these valves and the related failures are as follows:

(1) "C" Steam Generator Blowdown Trip Valve (1-BD-TV-100F) failed to close.

(2) Inlet Valve to the RHR System (1-RH-MOV-1701) failed to stay open following the reactor trip.

The inspector reviewed applicable deviation reports, work orders and root cause analyses, performed by Maintenance Engineering to address the problems.

In reference to blowdown isolation valve, 1-BD-TV-100F, results of the licensee's investigation show that the valve malfunctioned because the ASCO SOV was stuck in the energized position. The valve's function is to close on loss of power and/or air to the SOV, which is its "fail-safe" position. Because the application requires the solenoid to remain energized during plant operation, heat is generated and the licensee believes that this heat causes the small amount of silicone lubricant, used by the manufacturer during valve assembly, to oxidize and behave like a mild adhesive holding together the core/spring and solenoid subassemblies, as previously discussed in paragraph 3.a. With these SOV parts stuck together, the solenoid was prevented from repositioning itself when de-energized on reactor trip, and the pilot valve remained open. To overcome this problem, the licensee has increased the frequency of stroking these type valves and plans to replace five redundant SOVs used for outside containment isolation, as discussed in paragraph 3.a.

In reference to 1-RH-MOV-1701, residual heat removal suction isolation valve, the inspector ascertained that the valve failed to stay open because relay PC-143 failed to operate. However, at the time of this inspection, the subject valve was open and the suspect breaker was locked out in the off position. The licensee was delaying stroking this valve until after fuel had been removed from the reactor.

d. Steam Generator "C" Tube Leak Resulting from a Mechanical Plug Failure, Unit 1.

The inspector met with the licensee's cognizant engineer to discuss the status of planned corrective actions and obtain a progress report on the mechanical plug failure analysis by Westinghouse. The failed plug was located in S/G tube R3C60 of S/G "C". This failure has been discussed in NRC Inspection Reports 338,339/89-03 and 89-07. The plug was used by Westinghouse in November 1985 to remove the subject tube from service when eddy current inspection showed it to be defective. The plug in question was made from inconel-600 material produced from one of the two heats identified as NX3513 or NX3962. The material was processed by Huntington Alloy per ASME SB-166 and furnished as one inch, rough turned round bar in the as annealed condition.

A recent Westinghouse proprietary report on the failure analysis performed on a leaky mechanical plug, removed from tube R3C6 of S/G "A", North Anna Unit 2 in July 1987, reported that the plug had been made from the same heat of material. The report described the microstructure as one exhibiting various degrees of carbide network in the grain boundaries which is indicative of inadequate solution annealing, i.e., low annealing temperature, insufficient time at temperature or both. The material in question contains 0.018% carbon and exhibited a hardness level of HRB 104 or HRC 28.5. Further, the report stated that this hardness level was indicative of a significant amount of cold work resulting from manufacturing practices. The failure mechanism was identified as primary water corrosion cracking with an intergranular fracture. Mechanical plugs made from those two heats of material include 515 in North Anna Unit 1 and 319 in Unit 2.

A review of photographs of the failed plug, following its removal from S/G "C", showed that is had failed circumferentially at the second landing. The licensee is inspecting the tubes around R3C60 to verify wall integrity and stated that the adjacent tube sustained sufficient damage (dented) to preclude inspection with a standard size 0.720" diameter probe. The licensee will attempt to inspect the tube with either a 0.610" or a 0.580" diameter probe to determine the degree of damage.

In Unit 2, the licensee's tentative plans were to remove those plugs in which an engineering evaluation could not demonstrate safe operation when left in place (see paragraph 3.c for further details). In Unit 1, plugs which are shown as unacceptable for safe operation will be plugged with a specially designed appliance to preclude the recurrence of a similar failure.

No violations or deviations were identified.

6. Operating Reactor Events (93702)

The inspectors reviewed activities associated with the below listed reactor events. The review included determination of cause, safety

significance, performance of personnel and systems, and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate.

a. Transportation Problem with a Reactor Coolant Pump Motor

On March 27, the licensee informed the inspectors that the Westinghouse contracted trailer containing an RCP motor had broken down approximately 12 miles from the North Anna station. The inspector responded to the site of the breakdown and discovered that the box containing the motor was still upright and intact on the trailer. It appeared that the trailer, which was a low-boy, had fatigued in the center on the right hand side, allowing the bottom of the trailer to come in contact with the highway and generating several brush fires along a two mile stretch. The truck driver noticed that the load was getting much heavier, stopped the truck and notified the licensee at approximately 11:00 a.m.

The HP technician at the site of the breakdown informed the inspector that the radiation levels were as follows:

(1) The highest contact reading on the box external was 2 mr/hour

(2) General area around the box was 0.3mr/hour one meter from the box

(3) The highest reading inside the box next to the RCP was 5mr/hour at the top of the motor.

The inspector was also informed that no external or internal contamination to the box was detected. The motor itself was in a herculite bag and was reported to have both fixed and loose contamination, but none of the contamination was detected outside the bag. The licensee also informed the inspector that the activity of the RCP motor was estimated to be approximately 254 milicuries.

The licensee transported a crane and another low boy trailer to the site and lifted the motor from the damaged trailer to a new trailer. The motor was then transported back to the station. The motor was in the process of being shipped by Westinghouse to their facility in Pennsylvania for overhaul when the trailer failure occurred.

b. Loss of CCW to Unit 2 RHR Heat Exchanger

On April 3, the licensee experienced a loss of CCW to the Unit 2 RHR heat exchangers. The unit was in Mode 5 with the reactor vessel level at approximately 73 inches as indicated by the level standpipe. This level is approximately five inches below the reactor vessel flange; therefore, the licensee was not in a reduced vessel level inventory condition as defined by Generic Letter 88-17. The

operators determined the cause of the loss of CCW to be a loss of instrument air to the CCW containment isolation valves which caused the valves to fail closed. Instrument air was restored and the valves were reopened in approximately 25 minutes. The RCS temperature, as indicated by the RHR pump discharge temperature, increased from approximately 91°F to 96°F during the 25-minute period. Details of the event are listed below.

At approximately 1:00 p.m., the control room operator responding to an annunciator for RHR pump cooling low flow discovered the CCW containment isolation valves which also supply the RHR heat exchangers indicating shut in the control room. Operations personnel were immediately dispatched to the area in the auxiliary building where the CCW valves are located to determine cause for the closure and to reopen the valves. This effort was hampered due to the CCW valves being located in a contamination area requiring full anti-contamination clothing. At 1:21 p.m. the operators reported that there was no instrument air pressure to the CCW isolation valves. These valves are air to open and spring pressure to close. The operators proceeded to determine the cause for the loss of instrument air and in parallel to prepare a jumper to get an air supply to the CCW valves. At approximately 1:23 p.m. an operator discovered an instrument air manual isolation valve closed which isolated the air supply to the CCW valves. This valve was opened and both CCW valves were reopened by 1:25 p.m., resulting in RCS temperature (as indicated by RHR pump discharge temperature) to decrease back toward the original temperature.

The licensee determined, based on interviews with personnel in the area, that a contract painter had been working on piping just above the instrument air valve. This painter admitted to brushing up against the instrument air valve handwheel, but reportedly stated that he did not intentionally shut the valve. This instrument air valve is located approximately 12 feet in the overhead, and has approximately three turns from full open to full closed. The inspector along with the Station Manager and the Operations Superintendent entered the valve penetration area where the instrument air valve was located to inspect the valve. Based on observations and physical manipulation of the valve handwheel, the licensee determined that the valve was very easy to operate and could have been closed by the physical contact of the painter. Consequently, the licensee concluded that the valve had been inadvertently closed by the painter.

The inspector had entered the control room shortly after the operator had discovered the CCW isolation valves closed., The inspector observed the operations staff to be very sensitive to the loss of cooling water to the RHR heat exchangers and that prompt actions were being taken to restore the cooling water. These actions included notification of station management who responded to the control room, discussions by the operations coordinator with both the electrical

and instrument shops to determine if any work that they were performing could have caused the valve closure, dispatching operators to the area and trending the RHR pump discharge temperature. The emergency plan procedures were consulted to determine if any notifications were required and the abnormal procedures for loss of RHR were consulted.

c. Loss of 1H and 2J Emergency Busses

On April 16, 1989, at 1115, with both units in Mode 5, the station lost the "C" Reserve Service Station (RSS) bus due to improper bus rework and relay testing in the switchyard. The function of the "C" RSS bus is to provide power to the 1H and 2J emergency buses. The inspector was in the control room at the time of the event and observed the operations personnel response. Pressurizer levels during the event were 8 percent and 6 percent by cold calibration for Units 1 and 2 respectively. The units were not in a midloop operation at the time of the event.

The event occurred while contract personnel were performing an approved energizing procedure to rework the existing feed from the 34.5kv bus 4. The procedure did not detail all of the leads to be pulled or landed for the rework of the bus 4 feed. A technician had marked up a panel drawing, indicating the bus 4 leads to be pulled by an electrician. However, various leads from bus 3 were also marked on the drawing from another step in the procedure. The technician failed to inform the electrician not to pull the leads for bus 3 and left the immediate area. Consequently, when a bus 3 lead was lifted and went to ground, a 300 millisecond timer was activated and timed out, which then deenergized the "C" transformer. The technician, upon realizing that had occurred, immediately notified the operations personnel of the occurrence.

The loss of the "C" RSS power supply to the 1H and 2J emergency buses resulted in the 1H and 2J EDGs being auto-started. Component cooling pumps auto-started and loaded as designed on both units. The Unit 1 "A" RHR pump, which was running at the time of the event, tripped on undervoltage. Operations personnel entered 1-AP-11, Loss of RHR, and successfully started the Unit 1 "B" RHR pump. The decision to vent the "B" pump prior to starting was made because operations personnel were in the area at the time of the event and the pump had not been run recently. This did not significantly delay the reestablishment of shutdown cooling to the unit. All other major equipment functioned normally, and operator response was appropriate.

As part of the corrective actions to the event, the licensee discussed the evolution with the contractor technician. Further discussions were held with the contractor management on the impact of contractor actions on the safety of the plant. The licensee made a four-hour report on the event.

d. RCS Vessel Level

On April 26, Unit 1 was in Mode 5 with vessel level being maintained in a level band of 68" to 72" above nozzle centerline. This level band maintains level 26" to 30" above the "Reduced RCS Inventory" level of 42". The vessel level was being monitored by a standpipe located in the containment with a CRT monitor in the control room. The operators were maintaining this level band by periodically pumping any RCS leakage from the Primary Drain Transfer Tank (PDTT) to either the RCS via the RHR System or to the Gas Stripper system. Additionally, a head purge had been in progress for approximately 20 hours. During head purge, vessel level was erratic in indication but remained on-scale. On observing a decrease in process vent flow, the operators secured the head purge at 0224. When the purge was secured, the RCS standpipe level dropped below the lowest ruler mark indicated on the control room CRT monitor (68"). Personnel were dispatched to the containment to investigate, and a makeup was commenced to the RCS. RCS level was returned on scale in the control room at 0315. A total of approximately 546 gallons was added to the RCS from the VCT and level increased to 71". No problems were found with the system line up in the containment, and the licensee concluded the decrease in water volume was caused by diverting of inventory from the PDTT to the Gas Stripper system to keep RCS standpipe level on scale during the head purge. (Disc Pressurization of the RCS loop isolation valves from an Accumulator causes a positive in-leakage to the RCS of approximately .35-.5 gpm.) The licensee further concluded that the head purge affected standpipe indicated level by causing it to be erratic and indicate high.

On April 27 at 0500, with Unit 1 plant conditions as described above, RCS standpipe level was again observed to be excessively erratic in its indication. Head purge which had been in service at that time for approximately 18 hours was secured to check standpipe level. When the head purge was secured, standpipe level again went off scale low (below lowest observable indication on CRT monitor - 64"). Makeup from the VCT and PDTT was started and 860 gallons were added to restore level to 66". At 0545, a containment entry was made and verified level was at 54". Thus, level decreased less than 54" to a value that could have approached 42". Head purge was restarted and level increased to approximately 70".

The inspector reviewed the controlling procedures for the plant conditions and evolutions occurring at this time. These are 1-OP-5.4, Draining the Reactor Coolant System, and 1-OP-11.3, Purging the Reactor Vessel Head. Neither procedure 1-OP-5.4, nor any other procedure, addresses the methodology being utilized for the maintenance of reactor vessel level. Specifically, the PDTT would be pumped, as appropriate, to either the RCS (through a temporary jumper to the RHR system) or to the Gas Stripper system. Interviews with the operators indicated a satisfactory knowledge of this system line-up. The operators were also knowledgeable concerning RCS

leakage rates and accumulator in-leakage rates (calculated by the STA once a shift). However, since neither the RCS leakage calculations or the operators tracked the amount of inventory transferred from the PDTT to the Gas Stripper system, the maintenance of adequate reactor vessel level became primarily a function of an accurate standpipe level indication.

Procedure 1-OP-11.3 precludes draining of the RCS with a reactor vessel head purge in progress. Similarly, procedure 1-OP-5.4 cautions that draining of the RCS is not allowed while purging the reactor head. Interviews with the operators indicated that they felt in compliance with these procedures during a reactor head purge even when transferring the RCS inventory from the PDTT to the Gas Stripper system. The operators indicated that the purpose of the inventory transfer was for maintenance of reactor vessel level between 68" and 72" and not a purposeful lowering of level that would be accomplished by a draining operation. The operators recognized that the reactor head purge could cause standpipe level to be erratic and indicate inaccurately high. The assumption was made that although this level indication could be inaccurate, as regards the exact reactor vessel level, it could be relied on as a trending indicator to insure that vessel level was being properly maintained during PDTT pumping operations. This assumption proved to be incorrect with respect to pumping of the PDTT and associated diversions of RCS inventory to the Gas Stripper system. The operators' actions over a period of hours, although intending to maintain level, effectively established an RCS draining evolution. Procedure 1-OP-11.3 provides no guidance or precautions with respect to conducting evolutions that have the potential for reduction of reactor vessel level. Procedure 1-OP-5.4, Step 5.31 also cautions that during Reactor Vessel Head Purging operations, the RCS standpipe may inaccurately indicate low. This statement is at variance with what was actually observed to occur.

The failure to control RCS standpipe level and the failure to identify and correct the problem after the April 26 event is identified as an apparent violation (338,339/89-08-04).

7. Licensee Event Report Follow-up (90712)

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

(Closed) LER 339/89-006, Pressurizer Code Safety Valves Out of Tolerance. This LER documents the testing of the Unit 2 pressurizer code safety relief valves which is performed every refueling outage. The relief valves are removed from the plant and shipped to Wyle labs to be setpoint and leak tested. The results of the test indicated that the as found lift

setpoint pressure for the C relief valve (2-RC-SV-255IC) was below the TS 3.4.3 criteria of 2485 ±1% psig (actual setpoint was 2444) and that the A relief valve (2-RC-SV-2551A) leaked by the seat following the as found testing. The vendor performed maintenance on the valves and the as left setpoints were reported to be within the TS 3.4.3 criteria. During the previous Unit 2 outage in 1987, the A and B reliefs exceeded the TS criteria and again the C relief was below the TS criteria (as found 2447 psig). The licensee has not been able to determine a root cause for the setpoint drift.

(Closed) LER 339/89-05, Main Steam Safety Valve Setpoints Out of Tolerance. The LER documented the testing performed at Wyle labs of all 15 of the Unit 2 main steam code safety relief valves. Five of the safeties exceeded the TS criteria of ±1%, two of which were lower and three were higher than the TS criteria. The licensee conducted an evaluation and determined that the design pressure of the steam generators would not be exceeded even though three of the safeties had setpoints higher than the criteria. The LER also stated that all 15 valves exhibited some seat leakage following the as found testing. During the 1987 Unit 2 refueling outage, the licensee reported that 11 of the 15 code safeties exceeded the TS pressure setpoint criteria (all higher) and 14 of the 15 exhibited seat leakage following the as found testing.

The vendor refurbished and retested the valves to ensure that the as left pressure setpoints where within the TS tolerances and exhibited no seat leakage. The licensee has not been able to determine a root cause for the setpoint drift and leakage.

8. Action on Previous Inspection Findings (92701)

(Closed) Unresolved Item 338,339/88-33-07, Review of root cause analysis and corrective actions regarding ECCS pump breaker problems. In NRC Inspection Report 338,339/88-33, the inspector identified this URI pending determination by the licensee of root cause analysis and corrective actions concerning ECCS pump 480 volt breaker problems. A vendor representative from Brown Boveri overhauled and cleaned several 480 ITE breakers. The result of the inspection indicated that the roller surfaces and latches were sticky and difficult to rotate. Dried mud and debris were found inside the mechanism, and there was evidence that both degreaser and oil based solvents had been used on the breakers. It is suspected that a contributing factor to the breaker malfunction was the use of improper lubricant in non-compliance with the technical manual recommendation combined with leaving the doors to the building housing the breakers open with a fan blowing in dust and debris from outside during the hot weather months. As a result, the licensee is planning to initiate an EWR to be performed during this outage. The EWR will install a filter and fan in the room housing the breaker. The inspector will monitor the licensee's action during the hot summer months to determine if the breakers are maintained free of dust and debris.

In NRC Inspection Report 338,339/88-33 the inspector requested the licensee to provide information regarding operability of the B Quench Spray System since the pump breaker failed to close properly. Based on Technical Specification 4.3.2.1.3 and Table 3.3-5, the Quench Spray Pumps are required to develop an acceptable discharge pressure within 58 seconds. Periodic Test 1-PT-36.7.5 determined the response time for QS pump 1-QS-P-1B. The response time of 22.4 seconds was obtained during the last performance of 1-PT-36.7.5 and the operator approximated the time delay of the breaker closing to be 30 seconds. This places the pump performance very close to the Technical Specification limit. Pump 1-QS-P-1B could have been inoperable depending on the exact breaker closing time. The licensee submitted LER 89-001 "Sluggish Operation of ITE 480 Volt Breakers Due to Inadequate Lubrication" to document the problem. A review of this LER, revealed that the 480 volt breaker for the inside recirculation spray pump (1-RS-P-1A) failed to close within the time allowed by TS.

During the investigation of the maintenance procedure EMP-P-PL-01, 480 Volt Load Centered Air Circuit Breakers, the inspector determined that the procedure did not include the specific lubrication requirements, specified in the technical manual. The technical manual states that no lubrication is required during the circuit breaker normal service life. However, if the grease should become contaminated or if parts are replaced, any lubrication should be done with NO-OX-1D or Anderol grease as applicable.

Technical Specification 6.8.1.a requires written procedures shall be established, implemented and maintained, covering the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978. Section 9 of Regulatory Guide 1.33 requires procedures for performing maintenance. The failure of the licensee to have adequate maintenance procedures to ensure proper operation of ESF equipment breakers will be identified as a violation 338/89-08-01.

(Closed) Unresolved Item 338,339/89-03-03, NRC review of TS 4.6.1.1.a.1. The situation associated with this item involves the failure of the licensee to verify the position of the three quarter inch up to two inch capped vent and drain valves which are located within the containment penetration boundary as required by TS 4.6.1.1.a.1. The licensee informed the inspector that they had not considered these vent and drain valves as containment isolation valves. The licensee believed that the TS requirement only applied to manual isolation valves which isolated the main pipe penetration. Consequently, the licensee admitted that they did not perform the TS surveillance on these vent and drain valves.

TS 4.6.1.1.a.1 states, in part, that at least once per 31 days the licensee will verify all penetrations not capable of being closed by operable containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions. Periodic tests 1-PT-60.1 and 2-PT-60.1, Containment Integrity, is the test performed by the licensee every 31 days to comply with TS 4.6.1.1.a.1. This procedure

inspects approximately 43 containment penetrations to verify that the closure mechanism is closed (e.g. valve hatch, etc.). However, the vent and drain valves located between each containment isolation valve and the containment penetration (outside of containment) were not listed in this procedure. The failure of the licensee to comply with surveillance TS 4.6.1.1.a.1 will be identified as a violation 338,339/89-08-02.

9. Generic Letter 88-17 Loss of Decay Heat Removal (TI 2515/101)

The inspectors reviewed Generic Letter 88-17 and the licensee's response to the generic letter. At the time of the review, the licensee was preparing Unit 2 for entry into a reduced RCS inventory condition as defined by the generic letter. Prior to entry into a condition with RCS level less than three feet below the vessel flange of the applicable limit, the licensee experienced three events involving loss of RHR capability (see paragraphs 4.a, 6.b and 6.c). During these events, the operators demonstrated a heightened sensitivity concerning the loss of RHR and took prompt and aggressive corrective actions to restore RHR cooling capability.

The inspector has reviewed the licensee's procedures and controls regarding loss of RHR. The following is a brief description of the inspector's review.

a. Training

As discussed in NRC Inspection Report 338,339/88-36, the inspector attended the operator's training session associated with the loss of RHR events. The inspector felt the training was excellent for the time allotted. The inspector also attended a training session for maintenance personnel on April 5. This session discussed the effect maintenance activities can have on RCS level and the operating RHR pump and components. The training also described the additional controls which will be placed on any maintenance activity that can affect RCS inventory. The inspector felt that this training session covered the concerns and controls associated with performing maintenance during a reduced RCS inventory condition.

One observation made by the inspector was that the licensee did not document the briefings conducted with maintenance personnel subsequent to the initial training sessions. This observation was discussed with the licensee.

b. Containment Closure

The inspector reviewed 2-OP-5.4, Draining the Reactor Coolant System, and determined that the procedure required containment integrity to be established in accordance with 2-PT-91, Containment Penetrations, prior to RCS level being reduced to less than 42 inches above nozzle centerline. 2-PT-91 step 5.26 also requires that the containment closure team be established prior to RCS level reaching 42 inches.

The inspector verified that the SRO log listed the names of the maintenance personnel who were assigned to the containment closure team during a particular shift. The inspector also reviewed the containment breach log which was attached to 2-PT-91 listing all penetrations other than the equipment hatch and personnel hatch which had to be closed to establish containment closure.

One weakness identified by the inspector was the lack of procedural requirements for the establishment of the closure team, the training and briefing requirements for the team and the documentation of personnel attending briefings. However, during the present outage the inspector did not detect any lack of understanding of the purpose and requirements for the team. The reason appears to be the heightened sensitivity by both management and the operations staff to the issues concerning Generic Letter 88-17 and loss of RHR. However, in the future, if these requirements are not formalized, they may not get implemented as effectively.

The inspector has discussed this observation with the licensee and they have agreed to review the situation and provide some additional procedural guidance and controls. The inspector will review the licensee's actions again during the Unit 1 outage and will include a review of the licensee's procedural guidance associated with containment closure requirements.

c. RCS Temperature

The inspector reviewed 2-OP-5.4, Draining the Reactor Coolant System. This review revealed that step 4.9 and step 5.26 of the procedure required the operator to verify that two core exit thermocouples are operable prior to RCS level reaching 42 inches above nozzle centerline (three feet below the vessel flange). The core exit thermocouples are displayed on the core cooling monitor in the control room.

The inspector verified on several occasions while the Unit 2 reactor was in a reduced inventory condition that at least two thermocouples were operable and that the operator knew which ones were operable. During the times checked, the inspector observed five operable thermocouples indicating in the control and being logged by the operator in 1-Log-4A. The inspector compared the thermocouple temperature readings to the RHR pump discharge temperature and they were very close confirming the operability of the thermocouples. The RHR pump discharge temperature was also being recorded via a strip chart.

The inspector reviewed 1-AP-11.2, Loss of RHR. Attachment 7 of the procedure included a set of curves illustrating the heatup of the RCS following the loss of RHR. Even though Attachment 7 is located at the back of 1-AP-11.2, the inspector could not find any reference to

this set of curves in the body of the procedure. This observation was discussed with the licensee.

d. RCS Water Level

North Anna presently has only one means of RCS level indication during reduced inventory condition. This means of indication is a temporarily installed tygon hose with a TV camera and continuous monitor in the control room. In a letter from L. Engle, Project Manager, NRR, to W. Cartwright, Vice President, VEPCO, dated February 13, 1989, the NRC concurred with the use of only one means of RCS level indication for the short term at North Anna.

The inspector observed the RCS level indicatior via the TV monitor on each tour of the control room. The level indication was clear and easily read. The operators were monitoring the RCS level periodically and are required to log the results every 4 hours.

During RCS draining evolution, the inspector observed an operator in the control room on a head set monitoring the TV monitor while in communication with an operator in the containment locally monitoring the RCS standpipe level. The inspector observed portions of the level standpipe hose during a tour of containment on April 11. No problems were observed.

e. RCS Perturbation

The inspector reviewed 1-MISC-37, Assessment of Maintenance Activities for Potential Loss of Reactor Coolant Inventory. This procedure requires the Shift Supervisor to assess all work orders associated with the RCS, SI, RHR, RP or CVCS systems using the following criteria:

(1) Component cannot be isolated completely from RCS.

(2) Operator action is required to maintain system level to permit maintenance.

(3) Positive identification of component may not occur due to similar devices in a surrounding area.

If the assessment of the above indicates there is a potential for loss of RCS inventory, then the following actions are required:

(1) If maintanance requires an opening on the cold leg during mid-loop operation, establish and verify a hot leg vent path. Ensure proper administrative controls are established to maintain the hot leg vent path until system integrity is restored.

(2) Conduct a pre-job briefing with maintenance personnel. Discuss loss of inventory potential and contingency actions.

(3) Have an operator accompany maintenance personnel to positively identify the component and establish communications.

(4) Ensure makeup capability to the RCS is readily available.

(5) Establish communications between work site and control room.

(6) Notify the control room at the time work is started and when work is suspended.

(7) Monitor RCS level (standpipe, pressurizer level, cavity level, reactor vessel level) and containment sump level frequently during the process.

(8) Notify the control room when the component is closed and system integrity is restored.

All of the above items were discussed in detail during the maintenance training session attended by the inspector on April 5.

2-OP-5.4, Draining the Reactor Coolant System step 3.0 requires that MISC-37 be entered into the action statement status log and a copy forwarded to the Shift Supervisor. This procedure also requires the following:

(1) An operator to be stationed in containment in communication with the Control Room to monitor RCS level during draining evolutions.

(2) All personnel involved in the draining evolution must attend a pre-job briefing.

(3) No draining of RCS while purging the vessel head.

(4) The pressurizer PORVs and their isolation valves to be open venting the RCS.

The inspector found the procedure to be somewhat confusing, but did not observe the operators having any problems maintaining compliance with the generic letter requirements. The inspector discussed the procedure deficiencies with the licensee.

f. RCS Inventory Addition

The inspector verified that 2-OP-5.4 required that one HHSI and one LHSI pump be operable prior to the RCS level being lowered three feet below the vessel flange. 2-MISC-35.1, CRO Turnover Checklist (Modes 5 and 6), step 7 requires the offgoing and oncoming CROs to

list the two operable pumps and flow paths any time RCS level is three feet or more below the vessel flange. The inspector periodically verified based on control room indication the operable pumps and flow paths.

Abnormal procedure 2-AP-11.2, Loss of RHR, establishes the criteria for using the ECCS pumps to feed and bleed the reactor vessel. This procedure provides attachments with the requirements for the use of either the HHSI pump or LHSI pump to maintain the core covered and to remove decay heat.

g. Nozzle Dams

North Anna has loop stop valves and, therefore, does not use nozzle dams.

h. Loop Stop Valves

The inspector reviewed a memorandum from J. O. Erb, VEPCO, to D. A. Heacock, VEPCO, dated March 30, 1989, which stated that the required vent path for the hot leg side of the vessel should be greater than 19.19 square inches. This vent path is established to prevent the hot leg side of the vessel from pressurizing with all three of the hot leg stop valves closed and a hole in the cold leg side. The licensee's assumptions included 52 new fuel assemblies and 35 days since shutdown in determining the required vent size.

The licensee chose the vent path to be the flange opening for two of the removed pressurizer safety relief valves. The licensee determined that one opening was greater than 19.19 square inches but to be conservative, they elected to use two openings.

To prevent foreign material from entering the opening, the licensee installed screens over the openings. During a tour of containment the inspector observed the openings and the screens. It appeared to the inspector that the metal of the screens took up approximately half of the area of the opening. The inspector questioned the licensee and requested a calculation be performed determining the effective area of the openings minus the area of the screen metal. The calculation was performed and reported to the inspector. The report stated that the sum total of both openings was just over the requirement of 19.19 square inches (actual 21.22 square inches).

The inspector's overall observation of the licensee's actions regarding the potential loss of RHR was favorable. Both management and the operation staff demonstrated increased sensitivity toward any evolution potentially affecting RCS inventory. The actions and procedures, even though several procedural upgrades are needed, were more than adequate to comply with their commitments to the generic letter. The minor procedural inadequacies were compensated for by the operator training and resulting knowledge level of the

requirements for operating in a reduced RCS inventory condition. Although the licensee's program for operating during a known reduced inventory condition was favorably reviewed, an RCS level control event, which occurred after the generic letter inspection effort, revealed a fundamental problem with knowing the actual level when using the standpipe system. This issue is discussed in paragraph 6.d.

10. Refueling Activities (60705, 60710)

The inspector reviewed the completed refueling master procedure 1-OP-4.1, Controlling Procedure for Refueling. This review verified that the precautions, initial conditions and action steps were completed and signed off. The inspector observed that the applicable TS were listed in the procedure and verified each time they were applicable.

The inspector interviewed the refueling coordinator and the refueling shift supervisors. The inspector discussed the training activities for the Westinghouse refueling personnel. The coordinator informed the inspector that the contract refueling personnel were experienced refueling personnel and received the training well.

During the 1987 refueling outages, the refueling activities went well with the exception of two problems, one on each unit. These problems resulted from the contract refueling personnel failing to follow procedures. During the present Unit 2 refueling outage, the refueling shift supervisors informed the inspector that the contract refueling personnel were very receptive to their requests, unlike the previous outage. The inspector was also informed that the refueling personnel followed the procedures and their supervisor was very diligent in making sure that all refueling steps were complete and properly signed off.

The inspector reviewed the deviation reports documented against the refueling activities. This review did not reveal any problems similar to the two reported problems during the 1987 outages. There were a couple of minor discrepancies, but these errors did not have the potential for fuel damage and were discovered by the refueling shift supervisor and corrected.

The core off load commenced on March 14 and the reload was completed on March 29. The only problem experienced during the fuel movement in the reactor cavity involved new fuel assembly X44. This assembly would not line up and seat on the lower core plate. The assembly was removed and inspected. The lower flow nozzle suffered some damage due to the lower core plate alignment pens coming in contact with the lower nozzle feet. The assembly was replaced with the same type of new fuel assembly scheduled for Unit 1 refueling. The damaged assembly X44 had the bottom nozzle removed and both the assembly and nozzle were shipped to Westinghouse. The bottom nozzle will be replaced with a new one and the fuel assembly will be shipped back to the station for use in Unit 1.

11. Storage and Handling of EDG Fuel Oil (25588)

On January 16, 1987, the NRC issued IE Information Notice 87-04 to alert the licensee of potentially significant problems pertaining to long-term storage of fuel oil for EDGs. The inspector reviewed the licensee's programs for maintaining adequate quality of the EDG fuel oil stored on-site. Through reviews and interviews, the inspector determined that the licensee:

- Evaluated the aforementioned Information Notice and other similar industry events,

- Took actions as a result of the evaluation, including lean out of fuel oil tanks, evaluation of samples for biologic. growth, and evaluation of the use of additives to the fuel,

- Routinely samples the fuel oil for viscosity, water, and sediment in accordance with TS, and

- Inspects and cleans fuel oil filters and strainers during outages.

No violations or deviations were identified.

12. Exit

The inspection scope and findings were summarized on April 17, 1989, with those persons indicated in paragraph 1. The issue discussed in paragraph 6.d. was summarized with the licensee on May 2, 1989. 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.

Violation 338/89-08-01, Failure to have adequate maintenance procedures to ensure proper operation of ESF equipment 480 volt ITE breakers (paragraph 8).

Violation 338,339/89-08-02, Failure to comply with TS 4.6.1.1.a.1 for containment penetration vent and drain valves (paragraph 8).

Apparent Violation 338,339/89-08-03, Potential for the SW and RSHXs to have been inoperable (paragraph 4.b).

Apparent Violation 338,339/89-08-04, Inadvertent loss of reactor vessel level (paragraph 6.d.).

A licensee oral commitment to develop a formalized approach for obtaining control operations assistance and establish an implementation schedule by May 17, 1989, was discussed.

13. Acronyms and Initialisms

AP	Abnormal Procedure
CAD	Computer Assisted Drawing
CAE	Condenser Air Ejector
CDA	Containment Depressurization Actuation
CRO	Control Room Operator
DCP	Design Change Package
DHR	Decay Heat Removal
DUR	Drawing Update Request
EDG	Emergency Diesel Generator
EP	Emergency Procedure
ESF	Engineered Safety Feature
EWR	Engineering Work Requests
GPM	Gallons Per Minute
HP	Health Physics
IFI	Inspector Follow-up Item
IR	Inspection Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MCC	Motor Control Center
MOV	Motor Operated Valve
MPC	Maximum Permissible Concentration
MREM	Millirem
MSSV	Main Steam Safety Valve
NRC	Nuclear Regulatory Commission
NSE	Nuclear Safety Engineering
PDTT	Primary Drain Transfer Tank
PES	Plant Engineering Services
PORV	Power Operated Relief Valve
PROM	Programmable Read Only Memory
PSIG	Pounds Per Square Inch Gauge
PTSS	Periodic Test Scheduling System
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
RS	Recirculation Spray
RSHX	Recirculation Spray Heat Exchanger
RTD	Resistance Temperature Detector
RWP	Radiation Work Permit
S/G	Steam Generator
SALP	Systematic Assessment of Licensee Performance
SI	Safety Injection
SNSOC	Station Nuclear Safety and Operating Committee
SOV	Solenoid Operated Valve
STA	Shift Technical Advisor
SW	Service Water
TS	Technical Specification
TSC	Technical Support Center
UE	Unusual Event
URI	Unresolved Item
UFSAR	Updated Final Safety Analysis Report

VCT	Volume Control Tank
WOG	Westinghouse Owners Group