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

Report Nos.: 50-338/89-14 and 50-339/89-14

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: April 18, 1989 through May 31, 1989

Inspectors: M. S. Lewis for 6/27/89
J. L. Caldwell, SRI Date Signed

M. S. Lewis for 6/27/89
L. P. King, RI Date Signed

M. S. Lewis for 6/27/89
J. F. Munro, RI Date Signed

Approved by: P. E. Fredrickson 6/27/89
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: plant status, maintenance, surveillance, ESF walkdown, operational safety verification, operating reactor events, licensee event report followup, licensee action on previous enforcement matters, review of inspector follow-up items, plant procedures, plant startup from refueling, preparation for refueling, and evaluation of licensee self-assessment capability. During the performance of this inspection, the resident inspectors conducted reviews of the licensee's backshift operations on the following days: April 18, 25, 27, 28, 29, 30, May 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 16, 23, and 26, 1989.

Results:

Several weaknesses were identified associated with corporate related activities. The corporate independent review committee was not performing all of the TS required reviews, the formal check valve PM program was not developed as committed, the corporate FAI group failed to issue an accurate spent fuel pool map to the station, and corporate licensing failed to issue a TS required special report within the required 30 days. With respect to the indepen ent

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review committee, the inspector raised a concern about the licensee management's past attitudes toward this committee's regulatory performance, and over the ability of management to ensure future improved performance.

A strength was identified associated with the station's newly developed self-assessment program including the recent Unit 2 restart assessment. An additional strength was the successful restart of Unit 2 following the refueling outage. The unit was restarted without experiencing any power reduction.

Within the areas inspected, there were three violations, one additional example of an apparent violation, and one non-cited violation.

Violation: Failure of the licensee's independent review group to perform all of the reviews required by Technical Specifications (paragraph 14).

Violation: Failure to adequately control the location of fuel assemblies during fuel movement operations (paragraph 9).

Violation: Failure to adequately control maintenance operations with two examples (paragraphs 7 and 9):

1. Failure to follow procedures resulting in work being conducted on an unisolated charging system filter.

2. Failure to have adequate calibration procedures to prevent unexpected reactor trip signal generation.

Apparent Violation: Additional example of failure to provide design SW flow to the RSHX for Unit 2 (paragraph 5).

Non-Cited Violation: Failure to comply with TS 3.11.1.3 and submit a special report within the 30 days as required (paragraph 7).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Bowling, Assistant Station Manager
*G. Clark, Quality Assurance
J. Downs, Superintendent, Administrative Services
R. Driscoll, Quality Control Manager
*R. Enfinger, Assistant Station Manager
G. Gordon, Electrical Supervisor
*D. Heacock, Superintendent, Engineering
G. Kane, Station Manager
*P. Kemp, Licensing Coordinator
*J. Leberstien, Licensing Engineer
*J. Mosticone, Operations Administration Coordinator
T. Porter, NSE Supervisor
*D. Quave, Licensing Engineer
*C. Snow, Chemistry Supervisor
J. Stall, Superintendent, Operations
A. Stafford, Superintendent, Health Physics
F. Terminella, Quality Assurance Supervisor
D. Thomas, Mechanical Maintenance Supervisor
*W. Matthews, Superintendent, Maintenance
G. Flowers, Configuration Management Supervisor

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

*Attended exit interview

NRC Regional Site Management Visit: S. D. Ebneter visited the North Anna Power Station on May 4 to interface with the Resident Inspectors and perform a tour of the station.

On May 31, the Hungarian Vice Minister of Industry and two of his associates visited the North Anna Station at the invitation of the licensee. The minister and his group were given a presentation and a tour of the station.

2. Plant Status

On April 18, the beginning of the inspection period, Unit 1 was in Mode 5, day 51 of an outage. On April 26 and 27, with a reactor vessel head purge in progress and the resultant inaccurate vessel standpipe level indication, vessel level was inadvertently reduced by 546 and 860 gallons, respectively. However, vessel level remained above the reduced RCS inventory level as defined in Generic Letter 88-17 (see paragraph 6.d of NRC Inspection Report 338,339/89-08 for details).

On April 27, an attempt was made to place a new fuel assembly into a spent fuel pool location where another fuel assembly was currently stored. This occurred due to an incorrect fuel handling data sheet submitted by the corporate fuel audit and inspection group. Subsequent inspection showed no damage to either assembly (see paragraph 9 for details). Core offload was commenced on May 8 and completed on May 11.

On April 18, the beginning of the inspection period, Unit 2 was in Mode 5, day 57 of the refueling outage. Also on April 18, the "Flow Test of Inside Recirc Spray Pumps" was satisfactorily completed (see paragraph 5 for details). On April 21, containment pressurization in accordance with the Type "A" test procedure commenced. The Type "A" test was satisfactorily completed on April 23 with the containment depressurized and returned to atmospheric pressure on April 24. On April 24, the "Service Water System Flow Balance" for the RSHXs was completed. The results of the test revealed that one of the four Unit 2 RSHXs was not receiving the design SW flow (see paragraph 5 for details). On April 29, while increasing RCS pressure to start RCPs, PORV 2-RC-PCV-2455C lifted at approximately 350 psig. The valve, with a setpoint of 370 psig, lifted early due to an out-of-calibration pressure channel. On May 2, a Train "A" reactor trip signal, low steam generator level coincident with steam flow greater than feedwater flow mismatch, was inadvertently generated during the performance of the steam flow instrument channel calibration. A four-hour report was made in accordance with 10 CFR 50.72 (b)(2)(ii) (see paragraph 9 for details). On May 4, the Unit 2 heat-up commenced and Mode 4 was entered. On May 7, reactor startup commenced with criticality being achieved in approximately 5 hours. On May 8, the turbine generator was placed on line and core physics testing was satisfactorily completed. The unit achieved 100 percent power on May 16. During the startup, erratic feedwater flow to the "A" SG was periodically encountered. This problem was corrected on May 18, by replacement of the pilot valve associated with the MFRV positioner. On May 20, the CVCS letdown filter replacement maintenance was inadvertently commenced on the in-service RCS filter. Work was immediately stopped and filter cover bolts re-tightened when water began spraying during disassembly (see paragraph 7 for details). On May 30, entry into TS Action 3.7.12.1a was made on total settlement between the Unit 2 containment and Unit 2 MSVH being greater than 75 percent of allowable.

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 TS.

As documented in NRC Inspection Report 338,339/88-11, the licensee committed to develop a formal check valve PM program prior to the present Unit 1 and Unit 2 refueling outages. The failure to have a formal check valve PM program was also discussed as a weakness that needed management attention in the last SALP report. Consequently, VEPCO tasked corporate management with the development of this program. At present, this program has not been completely developed and is not scheduled to be fully approved until August 1989.

The inspector discussed the need for the program and the NRC commitment, with station management at the beginning of the Unit 2 outage. The inspector was later informed that the maintenance superintendent had obtained a draft check valve maintenance procedure which had been developed by Stone and Webster. This procedure established a list of 174 critical check valves. For various reasons, the maintenance department inspected 56 check valves during the Unit 2 outage of which 48, or approximately 30%, were from the critical check valve list. The maintenance superintendent intended to work approximately 30% of the critical check valves each outage for the next three outages unless otherwise directed by a formal PM program. The inspector was also informed that another 20% of the critical check valves were tested during the IST program. Therefore, approximately 50% of the Stone and Webster Unit 2 critical check valve list was either tested or inspected during the Unit 2 outage. Even though the department of the corporate office responsible for the development of the check valve PM program failed to comply with the NRC commitment, the inspector will not identify this as a deviation because of the effort put forth by the station maintenance department to address the check valve concern. This does, however, demonstrate a weakness in the licensee's corporate response to NRC commitments. The inspector will follow the check valve PM program for Unit 1.

On April 19 the inspector, accompanied by the licensee, conducted a walkdown of the Unit 1 and Unit 2 condenser air ejector piping. This walkdown was conducted to understand the licensee's determination of the failure mode of the Unit 1 air ejector radiation monitor during the last two SG tube leak events. The Unit 2 air ejector drain piping was observed to contain a loop seal, with check valves installed upstream to prevent reverse flow and subsequent loss of the loop seal. However, the Unit 1 drain piping loop seal did not contain the same check valves. Consequently, each time the Unit 1 air ejector would divert to containment, it placed the containment pressure (a vacuum) on the loop seal, drawing water up into the radiation monitor and, after the loop seal has been removed, drawing a high flow rate of dilution air from the drain line vent past the detector. The detector would fail low due to either the moisture or the dilution air.

The licensee was unable to explain why the check valves had been omitted from the Unit 1 design or added to the Unit 2 air ejector drain piping. This design difference could explain the fact that past operation of the Unit 2 air ejector radiation monitor had not demonstrated the same failures as the Unit 1 radiation monitor. The licensee has also observed a faster reduction in containment vacuum when the Unit 1 air ejector is diverted to containment than that of the Unit 2 air ejector. This reduction rate would be a result of the high dilution air flow into containment from the Unit 1 air ejector drain line vent after the loop seal had been removed. The licensee intends to install the check valves upstream of the Unit 1 air ejector drain line loop seal prior to the completion of the Unit 1 refueling outage.

No violations were identified.

4. Plant Procedures (42700)

Procedures were reviewed by the inspectors to verify that:

a. Procedure changes were made to reflect revised TS. A review was made of changes to technical specifications for 1988 and 1989, and the applicable procedures were checked to ensure the new requirements had been incorporated.

b. The 10 CFR 50.59 submittals were reviewed to ensure procedures had been changed according to requirements.

c. Temporary procedures and deviations written during the past year did not conflict with TS requirements.

d. The method of incorporating temporary procedure changes into procedures for emergencies and other significant events did not preclude proper and timely operator action during abnormal plant conditions.

e. Overall procedure content was consistent with TS requirements. Stepwise construction was compatible with checklist information and there were provisions for signoff on the checklist and appropriate TS limits were incorporated.

f. The procedures accomplished the evaluation within the design characteristics and applicable safety review considerations.

g. Precautions were taken to ensure safety-related operations are within applicable regulatory requirements.

h. Procedures, including checklists and related forms in plant working files, were current with respect to revision and temporary change.

The following is a list of the procedures reviewed:

2-OP-1.5	Unit Startup from Mode 3 to 2
2-OP-2.1	Unit Startup From Mode 2 to Mode 1
1-OP-7.1	Recirc of RWST Using Low Head Safety Injection Pumps
1-OP-7.1A	Valve Checkoff - Low Head Safety Injection System

1-OP-16.0	Fuel Pit Cooling and Refueling Purification
1-OP-16.1	Spent Fuel Pit Cooling and Purification System
1-OP-16.1A	Valve Checkoff - Spent Fuel Pit Cooling
1-OP-16.2A	Valve Checkoff - Refueling Purification
1-OP-21.7	Main Control and Relay Room Ventilation
1-OP-21.6	Main Control Room and Relay Room Air Conditioning
1-OP-51	Component Cooling Water Systems
1-OP-46.1	Instrument Air Compressor
2-AP-4.3	Malfunction of Nuclear Instrumentation (Power Range)
2-AP-22.1	Loss of 2-FW-P-2 Turbine Driven Aux Feedwater Pump
1-AP-27.2	Loss of Spent Fuel Pool System
1-AP-27.1	Loss of Spent Fuel Pool Level
1-AP-28	Loss of Instrument Air
1-AP-55	Loss of Control Room/Emergency Switchgear Room Air Conditioning
1-MOP-7.01	Low Head Safety Injection Pump (1-SI-P-1A)
1-MOP-16.02	Refueling Purification Pump - 1-RP-P-1B
1-MOP-16.2	Refueling Purification Filter 1-RP-FL-1A
1-PT-30.2.1	NIS Power Range Channel I (N-41) Functional Test
2-PT-30.2.2	NIS Power Range Channel II (N-42) Functional Test
2-PT-30.2.3	NIS Power Range Channel III (N-43) Functional Test
1-PT-57.1A	ECCS Subsystem - Low Head SI Pump (1-SI-P-1A)
1-PT-74.2A	Component Cooling Pump (1-CC-P-1A) Test
2-PT-88B	D.C. Distribution Capacity Test for Train B Battery
2-PT-85	D.C. Distribution Systems
2-PT-87	D.C. Distribution Systems Service Test

2-PT-86A	D.C. Distribution Systems - H Bus.
2-PT-86B	D.C. Distribution Systems - J Bus.
1-ES-1.3	Transfer to Cold Leg Recirculation
1-ES-1.4	Transfer to Hot Leg Recirculation
ADM 5.3	Review of Procedures
ADM 5.4	Processing New and Revised Procedures and Deletion of Procedures

The inspector determined that, overall, the procedures reviewed were technically adequate and would accomplish their intended purpose. However, several deficiencies were observed as described below:

Administrative and/or typographical errors were identified in 2-PT-30.2.2, 2-PT-30.2.3, 2-AP-4.3 and 2-AP-22.1. None of these errors would preclude proper completion of these procedures. The licensee has been informed of these errors and has indicated that appropriate corrections will be made. Certain reviewed procedures, although adequate to control the stated purpose and/or evolution, omitted several checks and/or verifications. Procedure 1-OP-7.1A did not align valves 1-SI-282 and 1-SI-283 (see Procedural Reference 1, Drawing Number 11715-FM-96A, SH 1 of 3). Procedure 1-MOP-7.01 removes pump 1-SI-P-1A from service for maintenance, however, the procedure does not verify that the recirculation spray cross tie valve, 1-SI-315 is shut (see Procedural Reference 2, Drawing Number 11715-FM-96A, SH. 2 of 3).

The inspector reviewed a signed-off copy of 1-OP-21.7 dated May 4, 1989. The present system lineup was unclear, in that both procedure step 4.3, which places the main control and relay room ventilation system in operation, and step 4.4, which removes it from operation, were marked as completed for the same procedure. Because times are not indicated on this multi-purpose procedure, the order in which the steps were performed is unclear. 1-OP-21.7 also makes several references to the "Control Room Isolation" switch. The switch is actually labeled "Control Room Exhaust Damper."

The inspector also reviewed the licensee's process for revising and deviating procedures. Administrative procedures that control this process are ADM-5.4, Processing New and Revised Procedures and Deletion of Procedures, and ADM-5.8, Procedure Deviations. Changes to procedures require SNSOC approval and review, and these approvals are documented on ADM-5.4, Attachment 2, block 15 and ADM-5.8, Attachment 1, block 12. The inspector determined that the actual signatures of approval are not always filled in. In lieu of the actual signature, the chairman's name is printed with the SNSOC secretary's initials. This methodology is not addressed by the administrative procedures and occurs approximately 25% of the time. A sampling of these instances were reviewed against the SNSOC meeting minutes. The SNSOC meeting minutes supported SNSOC review in each of these instances. This situation has been discussed with the licensee.

Two instances were noted in which documentation was not complete. The questions of Block 10 in Attachment 3, ADM-5.4 dated June 23, 1988, for procedure 2-AP-4.3, were not checked either yes or no. The Safety Evaluation/10 CFR 50.59 Review performed in accordance with ADM-3.9 on August 23, 1988, for 2-PT-71.3 was not annotated as "Approved," "Disapproved" or "Return for Further Evaluation." SNSOC meeting minutes support review of these procedures.

The original "Evaluation for Potential Unreviewed Safety Question" (ADM-3.9, Attachment 1) for 1-PT-68.1.1, 1-PT-68.1.2, 1-PT-68.2.1, and 1-PT-68.2.2 was not available in Station Records. However, a copy was obtained from the STA's files and the licensee is taking action to address this recordkeeping omission.

No violations or deviations were identified.

5. Surveillance (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.

On April 18, 1989, the inspector observed the performance of the periodic test 2-PT-64.8, for the Unit 2 Inside Recirculation Spray Pumps. Both "A" and "B" pumps tested satisfactorily. The inspector attended the licensee's meetings prior to the performance of the test and discussed the test procedure and set-up with the test engineer. Operational, radiological, and safety aspects of the test were discussed by the test engineer with those performing the procedure in a professional and thorough manner. Interaction between the control room operator and test personnel during the test was acceptable. Procedure 2-PT-64.8 requires that temperatures of the recirculation system sump water be recorded from control room indications so that temperatures are maintained below 150 degrees F for personnel protection. The inspector also noted that sump water temperatures could be monitored near the pump suction location to give a more timely and accurate reading for the safety of the test performers. The inspector believes that this additional local indication should be useful for future test monitoring.

During the "A" recirculation pump testing, the rotation light failed to indicate in the control room. The indication light had been checked prior to performing the test and was determined to be operational. A work request was written to correct the problem. At the end of the tests, the inspector compared the recirculation pump head curve data to the last test performed in October 1988, and also to the manufacturer's stated pump head curves. By these indications, neither the "A" or "B" pump has suffered any significant degradation. All test acceptance criteria were met.

On April 24, the inspector witnessed the performance of 1-PT-62.2.1, RSHX SW Leakage, Surveillance Test. This test is conducted to verify that the RSHXs are maintained in a dry condition. During the performance of the test, the operator opens a low point drain on both the supply and return SW headers to and from the RSHXs and measures the amount of SW removed from the header. Based on the amount measured, the licensee can verify if any SW has reached the RSHXs. The acceptance criterion is less than 100 gallons, even though the piping to some of the RSHXs would require approximately 1000 gallons to reach the actual heat exchanger tube sheet. On April 24, the measured leakage was approximately 5 gallons in the supply header and 0.20 gallons in the return header.

Also, on April 24 the inspector witnessed the performance of 2-PT-75.6, Service Water System Flow Balance, for the Unit 2 RSHXs. The Unit 1 RSHXs were tested on April 14 as discussed in NRC Inspection Report 338,339/89-08. The results of the Unit 2 test indicated that three of the four SW throttle valves were adjusted such that greater than the design flow of 4500 gpm was achieved through the respective RSHXs. The fourth throttle valve, 2-SW-203D, had been adjusted improperly, limiting the SW flow through the 'D' RSHX to approximately 3600 gpm. The licensee subsequently adjusted all four of the SW throttle valves to establish a flow of greater than 4500 gpm through each RSHX. Failure to provide the design basis SW flow to the 'D' RSHX on Unit 2 is identified as an additional example of apparent violation 338,339/89-08-03. The licensee also determined the maximum allowed flow through the Unit 1 CCW heat exchangers and still be able to maintain the 4500 gpm through each Unit 2 RSHX. This was performed using the same method described in NRC Inspection Report 338,339/89-08.

During the performance of the test, the inspector was informed that one of the throttle valves did not have the mechanical stop installed. After further discussions, the inspector determined that the mechanical stops on all four Unit 1 RSHX SW throttle valves had been discovered to be missing during the April 14 test. Also, based on the test data from both tests and a review of the Setpoint Document, the licensee determined that the as-found throttle valve settings did not agree with the setpoint document. Both of these findings indicate that problems exist with the maintenance activities that have been conducted on these valves in the past, either due to improper performance or inadequate procedural guidance.

On April 30, the inspector reviewed the completed surveillance procedure 2-PT-10, Determination of Shutdown Margin. The minimum shutdown margin of 2203 pcm was determined by the surveillance test to comply with the TS 3.1.1.1 limit of greater than equal to 1.77% delta K/K. The actual shutdown margin was calculated to be 4286 pcm. The inspector had a licensed SRO step through the procedure to determine acceptability of the results. No problems were identified.

The inspector witnessed several additional tests which were completed satisfactorily. On May 1, 1989, the inspector witnessed the start of 2-PT-83.4, Blackout of Emergency Bus for Shutdown Loads for the 2J EDG. The diesel was operated for 24 hours, two of which were at 2950 KW and the remaining 22 hours were at 2500 to 2600 KW. Following the completion of the 24 hour test, the diesel was secured for approximately 5 minutes, then the normal power supply to the J bus was removed and the J diesel auto started and picked up the loads within the allowable times. No problems were identified. On May 2, 1989, the inspector witnessed performance of Appendix G of 2-PT-61.4, RCS Pressure Isolation Valves - Leakage Test. The licensee experienced a problem with the alternate charging header remaining pressurized. This required the procedure to be deviated to bleed the pressure off through several drain valves. Once the alternate charging header was depressurized, the leakage test was satisfactorily completed. On May 7, 1989, the inspector witnessed 2-PT-30.2.2 and 2-PT-30.2.3, NIS Power Range Channel II (N-42) and III (N-43) Functional Tests. The tests were satisfactorily conducted in accordance with the procedure. On May 8, 1989, the inspector witnessed 2-PT-212.6, Valve Inservice Inspection, for three accumulator motor operated valves. Position indication was verified inside the containment. All three valves completed the stroke test time satisfactorily.

6. ESF System Walkdown (71710)

On May 24 and 25, the inspectors walked down the auxiliary feedwater system on Unit 2 using valve checkoff list 2-OP-31.A and drawing number 12050-FM-074A Rev. 24. The inspector noted that the check valves in the lube oil cooler line installed by EWR 88-178A were not reflected in the drawing. The inspector checked the control room drawings and found that they had been redlined to reflect these valves. The inspector also noted that the cooler outlet isolation valves 2-FW-600, 601 and 602 were not shown on the drawing or redlined on the control room drawing. However, the valves were correctly listed on the valve checkoff list. The licensee is investigating the drawing discrepancy and will be updating the control room drawings to reflect these valves.

No violations or deviations were identified.

7. 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 LCOs.

In the course of the monthly activities, the resident 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 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.

The inspector reviewed a special report dated April 7, 1989, which was submitted by the licensee in accordance with TS 3.11.1.2 and TS 3.11.1.3. These TS require a special report be submitted to the Commission within 30 days any time the release or discharge limits for the associated TS LCO are exceeded. The non-compliance with TS 3.11.1.3 involved the discharge of effluents without going through the final demineralizer when the actual dose projections were in excess of the TS limit. This non-compliance began on February 20 and continued until March 2, when the dose projection error was discovered. However, as stated above, the special report was not issued by the corporate office until April 7, in excess of the 30 days required by TS 3.11.1.3. Since this violation of TS meets the criteria of 10 CFR Part 2, Appendix C for licensee identification, it will be identified as NCV 338,339/89-14-04.

On May 12, preparations were commenced to replace the filter elements in the Unit 2 letdown filter 2-CH-FL-5. A team of 2 mechanics and 1 health physics technician proceeded to the job location to perform the radiation surveys required to complete the RWP. There are two unlabeled filter access plugs in the same area, one for 2-CH-FL-5 and one for 2-CH-FL-2. The team used an informally marked up radiological survey map and record form as the reference to determine the access plug to be removed. On May 16, the SNSOC approved RWP 89-2256 to remove and replace the filter element for 2-CH-FL-5. The associated RWP was posted on the wall south of filter 2-CH-FL-2 instead of 2-CH-FL-5. On May 20, the licensee commenced procedure MMP-C-FL-5 to replace filter 2-CH-FL-5. The area established by RWP 89-2256 was covered by herculite except for one access plug. This access plug, assumed to be the plug for 2-CH-FL-5, was removed. As the fourth bolt on the filter cover was removed, water began spraying from the filter cover. The cover bolts were immediately tightened and the spray of water stopped. The job was stopped and supervision informed. A shift operator was dispatched and the determination made that the wrong filter had been worked, 2-CH-FL-2 versus 2-CH-FL-5.

TS 6.8.1.a requires written procedures be established, implemented and maintained covering maintenance activities. The failure of the licensee to follow MMP-C-FL-5, the associated work order and RWP resulted in maintenance being conducted on an unisolated charging system filter and will be identified as the first example of Violation 338,339/89-14-02.

8. Plant Startup From Refueling (71711)

During the previous SALP period, the licensee received a category 3 rating for the outage functional area. The primary reason for the category 3 rating was the licensee's inattention to detail during unit shutdown, startup and outage situations, which resulted in plant events. Consequently, the inspectors closely observed the Unit 2 refueling outage. As discussed in NRC Inspection Report 338,339/89-08, the inspectors observed the Unit 2 shutdown for the refueling and determined that evolutions were well controlled and conducted in a safe manner.

During the recent recovery of Unit 2 from the refueling outage, the inspectors observed the licensee's startup activities around-the-clock. The Unit 2 mode change from Mode 5 to Mode 4 occurred on May 7 with the reactor achieving criticality at 2234, control bank D at step 128. Unit 2 was placed on line on May 9 and, after secondary chemistry holds and correction of some vibration problems on the main turbine, achieved 100% power on May 16. The inspectors observed the startup to be deliberate and controlled, and the operator's full attention was placed on the unit's performance. There were no major perturbations associated with the startup, as were common for startups from the refueling outages in the past. The inspectors believe that the successful startup of Unit 2 was a result of many licensee initiated activities. The licensee provided startup training for the operations staff on the simulator. Attention to detail was emphasized by all levels of management. The station manager set a goal for the station to start up the unit, achieve 100% power and maintain operations for at least 30 days without any major power reductions. Station management established a startup assessment program for which the presentation was conducted on May 3 with the Station Managers. As discussed further in paragraph 14, this program involved the superintendents of each department making presentations to the station oversight board on how their responsibilities were accomplished to allow the unit to restart. This provided station management with a list of items left to be completed prior to restart and objective evidence that the unit was in fact ready for the restart. The resident inspector attended portions of the Unit 2 restart assessment.

The successful startup, as well as the low number of equipment problems following the startup and the low identified and unidentified leakage rates, also reflected an adequately conducted outage. The actual time the unit was in the outage exceeded the original scheduled time. However, much of this could be attributed to the unplanned February outage for Unit 1, and the fact that the Unit 2 outage was driven more by satisfactory completion of the necessary maintenance versus strictly meeting the schedule.

Prior to the Unit 2 restart, the inspectors conducted the following inspections:

- On April 26, the inspector made a Unit 2 containment entry to check the lineup of the low head safety injection system. The leakage monitoring valve for penetrations 60, 61 and 62 were verified closed and capped. No problems were found.

- On May 1 and 2, the inspectors made containment entries into Unit 2 with licensee representatives. A walkdown was made of the first, second and third levels of the containment using 2-OP-1B, Containment Checklist. Areas inside the A, B and C cubicles on the shroud cooler level needed vacuuming. There were pieces of red tape on various walls and floors throughout containment. Several welding rods, rags and other small material were picked up during the course of the checkout. The licensee noted all discrepancies to be closed out before final heatup. The inspectors did not notice any major items or equipment which were left in containment. However, the material found and removed should have been removed by the maintenance and/or contractor groups as they completed their activities, to prevent unnecessary exposure at the end of the outage.

- On May 6, the inspectors witnessed portions of 2-PT-17.2, Rod Drop Time. The procedure was completed satisfactorily with the rod drop times meeting the TS criteria. The inspector did observe a couple of problems associated with the performance of the test procedure. Steps 2.2.2 and 4.2.5.4, related steps, were signed off even though the steps were not actually performed. The function required by the steps was stated to be optional, therefore, the steps were not required to be performed, and could have been annotated to indicate that the option was not taken. Step 4.2.5 was not going to be performed until the inspector questioned how the reactor engineer could sign the step and not perform it. The engineer informed the inspector that because they were using a new calibrated recorder to record the rod drop traces, the step was no longer required. Based on the inspector's discussions regarding the deviation process, the engineer chose to perform step 4.2.5 rather than deviate the procedure. The signing off of steps that are not performed is inconsistent with the attention-to-detail/follow-procedure philosophy supported by station personnel. The inspector has discussed this with the licensee.

- On May 6, the inspector witnessed portions of the following procedures:

  a. ICP-RP-2-RPI-1, Rod Position Indication

  b. 2-PT-714, Auxiliary Feedwater Pump Time Response and Logic Test

  c. 2-PT-71.1, Auxiliary Feedwater Pump (2-FW-P-2) and Valve Test

d. ST-81, Auxiliary Feedwater Pump Head Curve Verification

No problems were observed.

- On May 7 and 8, during the Unit 2 start-up, the inspectors observed the performance of sections of the following procedures:

  a. Unit 2 startup from Mode 4 to Mode 3 per 2-OP-1.4, Withdrawal of the Shutdown Banks. This evolution was performed in a deliberate and controlled fashion to ensure that TS regarding to rod position indication were being complied with.

  b. Nuclear Design Check per PT-94.0, for the determination of the reactivity worth of Shutdown Bank B. The inspectors also observed parts of the procedure for boron end point determination, isothermal transfer coefficient testing and B group rod worth. The control manipulations were performed in a controlled and deliberate manner, and in accordance with PT-94.0.

  c. Estimated Critical Position per 2-OP-1C, to determine the bank and range of control rod position expected to achieve criticality. This procedure was designed to be performed following a routine reactor trip. Consequently, several steps had to be NA'd, and the operators and STA needed the reactor engineer to explain what information was required to be placed in several of the steps. The estimated critical position was adequately determined. The inspector discussed the confusing nature of the procedure with the licensee. The licensee stated that they intend to make the procedure applicable to a startup following a refueling outage.

No violations or deviations were identified.

9. 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.

On April 27, new fuel movement to the spent fuel pool was in progress in accordance with procedures for Receipt and Storage of New Fuel, 1-OP-4.2, and Fuel Building Bridge and Trolley Crane, 1-OP-4.10. The controlling document for the fuel assembly location was the Fuel Handling Data Sheet generated by the corporate FAI group. While attempting to place a new fuel assembly, K65, in fuel pool location V30, a 200 lb. slow load loss was noted as fuel assembly K65 entered the storage cell. In accordance with 1-OP-4.10, fuel movement was stopped immediately and fuel assembly

K65 was raised to inspect the storage cell. The inspection showed a fuel assembly already stored in fuel pool location V30. A review of local records indicated this assembly to be N47. This conclusion was later confirmed by a video inspection. Facility records, Form VNF-7, Number NA-1-01-89, indicated that fuel assembly N47 had been placed in pool location V30 on January 26, 1989. A copy of this VNF-7 form had been forwarded to FAI group by company mail for entry into the tracking system, which is used to update the FHDS. However, this VNF-7 was not entered into the FHDS by the corporate group, resulting in the official FHDS being in error. Subsequent to the occurrence, local facility records and the magnetic tag board utilized to track fuel movement were verified to be correct and up to date. This board was then used to check the official FHDS issued by FAI prior to further fuel movement. In the past, station personnel were not required to review the accuracy of the FHDS with respect to the magnetic tag board or other station records prior to fuel movement. A video inspection of assembly N47 showed no damage. A visual (out of pool) inspection of assembly K65 showed no damage.

As further corrective actions, the licensee made the following changes to 1-OP-4.10 on April 28.

a. Prior to all fuel movement, the VNF-7 covering the moves to be performed will be verified by the fuel handling supervisor in charge against the magnetic board in the station refueling office.

b. The fuel handling supervisor will ensure that lighting in the fuel pool will permit visual verification of all moves. If lighting is not adequate, auxiliary lights will be used as required to assure proper visibility.

Also, the method for transmission of fuel movement information, i.e., completed VNF-7 or FHDS forms, to the FAI group has been revised to ensure receipt. The completed forms will be telexed to the FAI group, as well as mailed, with a response required from FAI indicating that the fuel movement data has been received and recorded. During discussions with FAI, the inspector determined that FAI personnel feel it is not necessary to be on site during fuel movements for first-hand verification of the fuel assembly locations.

TS 6.8.1.b requires written procedures to be established, implemented and maintained covering refueling activities. The failure of the corporate FAI group to provide an accurate FHDS will be identified as a Violation 338,339/89-14-03.

On May 2, with Unit 2 in Mode 5 and all rods fully inserted, an unexpected automatic RPS reactor trip signal was generated during the performance of procedure ICP-FW-2-F-2486, SG B Feed Flow Protecion Channel IV. The "A" train reactor trip breakers were closed for the performance of 2-PT-36.1B, Reactor Protection and ESF Logic Test Train B. SG "B" was being flushed and drained below 25% narrow range level. During the performance of ICP-FW-2-F-2486, the "B" S/G channel IV Steam Flow/Feedwater Flow is placed in trip and a SF/FF mismatch signal generated on channel IV of the "B" SG. Since an actual low SG level existed on the "B" SG, the placing of the "B" SG channel IV SF/FF mismatch bistable in trip completed the logic (less than 25% level on any SG coincident with a SF/FF mismatch on the same SG) and generated a reactor trip signal. The reactor trip breakers opened as designed. Since a reactor trip signal was not expected, the event is reportable pursuant to 10 CFR 50.73(a)(2)(iv). A four-hour report was made in accordance with 10 CFR 50.72(b)(2)(ii). The licensee addressed the procedural inadequacy by the issuance of a memorandum requiring a review of current plant conditions against procedural coincident logic requirements prior to proceeding with the procedure.

TS 6.8.1.a requires written procedures to be established, implemented and maintained covering maintenance activities. Procedure ICP-FW-2-F-2486 was inadequate in that the procedure's initial conditions stated that there were no coincidence requirements during modes 3, 4, 5 or 6 which could result in an inadvertent reactor trip signal. The inadequate procedure will be identified as the second example of Violation 338,339/89-14-02.

10. 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 338/88-03, Failure to Test Containment Personnel Airlock Equalizing Valves. The inspector reviewed the LER closeout package. The licensee satisfactorily leak-tested the emergency equalizing valves as an immediate corrective action. In addition, the containment surveillance procedure, 1/2-PT-62.1, was revised to delete the requirement that the emergency equalizing valves be blank flanged during testing. These corrective actions should preclude recurrence of the event.

(Closed) LER 338/87-010, Steam Generator Defects. The inspector reviewed the supplemental LER, which detailed the tube examination results. Because of the tubesheet indications, two tubes were removed from the "A" SG for further nondestructive and destructive examination. Preliminary results of the examinations performed revealed circumferential pressurized water stress erosion cracking in the expansion transition region of both tubes at the tube sheet top location. Also identified was minor outside diameter intergranular corrosion within the first support plate region of one tube and just above the top of the tube sheet region of both tubes. The licensee has plans to implement a thermal stress relief program for Unit 2 during the next refueling outage. The program is not being implemented for Unit 1.

(Closed) LER 338,339/88-010, Kaman Vent Stack "B" Radiation Monitor Exceeded T. S. Action Statement. The licensee issued supplemental LER 88-010-01 on March 3, 1989. A root cause investigation of the erroneously high radiation level being displayed for RI-VG-180 revealed that the CPU board had malfunctioned. The most probable cause was the ground configuration of the CPU. The licensee's corrective actions included replacing the failed CPU board and as a continuation of the reliability upgrade project (initially mentioned in LER 338,339/88-006), the licensee initiated a field change to improve the reliability of the monitor. This modification included ground configuration improvements. This event was unrelated to a previous failure of the Kaman Process Vent Radiation Monitor which failed on November 24, 1987, due to intermittent continuity problem on the CPU card on the card edge connectors. The inspector reviewed the TS applicability and the LER closeout package.

11. Licensee Action on Previous Enforcement Matters (92702)

(Closed) Violation 338,339/86-28-01, Failure to take prompt corrective action to ensure compliance with 10 CFR 50.49. This violation was as a result of licensee engineering not taking prompt action to establish environmental qualification for equipment in the MSVH. The criteria for initiating Deviation Reports covering the identification of potential and actual conditions adverse to quality was clarified to the engineering organization. The Engineering Department procedure for evaluating NRC Information Notices, vendor notifications, and other pertinent operating information has been revised.

12. Review of Inspector Follow-up Items (92701)

(Closed) Unresolved Item 338,339/88-11-02, Potential for the recirculation spray heat exchangers to have been inoperable during plant operations with the service water supplied by lake water at a temperature greater than 83 degrees F. This item is being closed based on the licensee's evaluation of the previous condition of the RSHXs, the chemical cleaning of the RSHXs, and the leakage monitoring program initiated to ensure that the RSHXs are maintained in a clean, dry condition. The licensee's original analysis of the operability of the RSHXs assumed a SW flow rate of 4500 gpm. During a management meeting (June 8, 1988) in Atlanta, the licensee reported that they had 4500 gpm SW flow through the RSHXs during the chemical flushing of the heat exchangers. Based on the testing that has been performed during this outage (See NRC Inspection Report 338,339/89-08, paragraph 4), it is clear that the SW flow rate through several of the RSHXs was not 4500 gpm. The question of operability of the RS system will continue to be tracked by the apparent violation discussed in paragraph 4 of NRC Inspection Report 338,339/89-08. Therefore, this unresolved item is considered closed.

(Open) IFI 339/89-03-05, Determine cause for failure of 2-CH-2115E to close and cause for the reset sticking of relay K-604 during safety inspection functional test and take corrective action. The failure of 2-CH-2115E to close was determined by the licensee to be a limit switch adjustment problem. The limit switch was readjusted and the valve was retested satisfactorily. This IFI will remain open pending the licensee's resolution of K-600 relay sticking problems.

(Closed) Item 338, P2186-01, Power supply failures of SLV relays. The licensee has indicated that all applicable in-service SLV ratings have had their power supply circuitry modified to prevent power supply "hang-up" on relay energization. Documentation for this modification is not presently available for review. This item is closed and re-opened as IFI 338,339/89-14-05 pending licensee submittal of the referenced documentation.

13. Preparation for Refueling (60705, 60710)

On April 30, the inspector reviewed the completed refueling master procedure 2-OP-4.1, Controlling Procedure for Refueling. No problems were identified. This review was conducted to close out the completed Unit 2 refueling evolutions and facilitate the preparations for the Unit 1 refueling.

On May 5, the inspector attended a briefing conducted by the Westinghouse Supervisor in charge of refueling activities concerning the impending vessel head lift and subsequent fuel movement. During the briefing, the refueling shift supervisor provided some additional comments, including an explanation that he was the final authority on stopping and starting the refueling evolutions. Refueling activities actually commenced on May 8 and the core off-load was completed on May 11. The inspectors witnessed several fuel assemblies being off loaded. Also, prior to the core off-load, the inspector observed the performance of 1-OP-41.5, Manipulator Crane, and the resulting setting of the crane limit switches. The core on-load did not recommence during the inspection period due to the ISI activities being conducted on the vessel. These inspections did identify several indications in the vessel and nozzle welds which will be reviewed by a regional inspector. The information concerning these vessel indications will be provided in NRC Inspection Report 338,339/89-20.

The licensee will be conducting UT inspections of the fuel assemblies removed from the vessel to locate any leaking assemblies. The RCS activity on Unit 1 was elevated prior to the refueling outage indicating problems of leaking fuel assemblies. The licensee had experienced some baffle jetting in the past and is installing additional grid straps on susceptible fuel assemblies until long-term corrective action can take place. The inspectors will continue to follow the refueling activities.

14. Evaluation of Licensee Self-Assessment Capability (40500)

The inspectors conducted a review of the licensee's self-assessment capabilities during this inspection period. The review involved the attendance at several of the licensee's off-site and on-site independent and safety committee review meetings, a review of previous committee meeting minutes, a determination of the licensee's compliance with TS and the overall effectiveness of the review committee. Based on these reviews, the inspectors concluded that the corporate independent review group was not in full compliance with TS. Corporate management, though, is in the process of significantly upgrading the independent oversight functions. The inspector did identify a strength in the licensee's self-assessment capabilities. This strength involved North Anna station management's implementation of the self-assessment program and the recent startup assessments performed prior to the unit restart from the refueling outage. Both of these items have provided station management with more objective tools to be able to make informed decisions and to provide management attention where it is most needed.

On May 17, the inspector attended a MSRC meeting conducted in the licensee's corporate office. The MSRC, a recently developed management oversite committee, was established by the licensee to provide a broad management overview of all nuclear related activities and to act in an oversight role for other groups performing review functions. The committee chairman will be the Vice President of Nuclear Operations, with the Vice Chairman being the Assistant Vice President of Nuclear Operations. The committee members will include both of the station managers, the corporate managers associated with nuclear support, and at least one consultant. The meeting attended by the inspector was the committee's second meeting. In that the charter had just been developed, the committee will function for several months before a TS amendment would be submitted to establish the committee as a TS independent review group. The information provided in the meeting was very well presented and the questions raised by the committee showed both an interest and concern for the topics being presented. However, since this was the second meeting, the committee has not developed a method for addressing their concerns and tracking these items to ensure that they are properly resolved. This particular problem was identified during the meeting to be resolved by the next meeting. The inspector believes that this committee, if properly implemented and maintained, will be an effective method for corporate management to maintain an up-to-date understanding of the issues reviewed and ensure that the proper management oversight is being provided. The inspector plans to attend several committee meetings in the future to determine the actual effectiveness of the process.

Also on May 17 and 18, the inspector conducted a review of the licensee's TS required independent review committee. This review involved attendance of a review committee monthly meeting on May 18, a review of previous committee meeting minutes, a review of the group's implementing procedures, discussions with several of the staff specialists and a determination of the committee's compliance with TS. TS 6.5.2.7 requires the following subjects to be reviewed by the corporate independent review committee:

a. Written safety evaluations of changes in the stations as described in the Safety Analysis Report, changes in procedures as described in the Safety Analysis Report and tests or experiments not described in the Safety Analysis Report which are completed without prior NRC approval under the provisions of 10 CFR 50.59(a)(1). This review is to verify that such changes, tests or experiments did not involve a change in the technical specifications or an unreviewed safety question as defined in 10 CFR 50.59(a)(2) and is accomplished by review of minutes of the Station Nuclear Safety and Operating Committee and the design change program.

b. Proposed changes in procedures, proposed changes in the station, or proposed tests or experiments, any of which may involve a change in the technical specifications or an unreviewed safety question as defined in 10 CFR 50.59(a)(2). Matters of this kind shall be referred to the Director-Safety Evaluation and Control by the Station Nuclear Safety and Operating Committee following its review prior to implementation.

c. Changes in the technical specifications or license amendments relating to nuclear safety prior to implementation except in those cases where the change is identical to a previously reviewed proposed change.

d. Violations, REPORTABLE EVENTS and Special Reports such as:

(1) Violations of applicable codes, resultations, orders, Technical Specifications, license requirements or internal procedures or instructions having safety significance;

(2) Significant operating abnormalities or deviations from normal or expected performance of station safety-related structures, systems, or components; and

(3) ALL REPORTABLE EVENTS submitted in accordance with Section 50.73 to 10 CFR Part 50 and Special Reports required by Specification 6.9.2.

Review of events covered under this paragraph shall include the results of any investigations made and recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

e. The Quality Assurance Department audit program at least once per 12 months and audit reports.

f. Any other matter involving safe operation of the nuclear power stations which is referred to the Director-Safety Evaluation and Control.

g. Reports and meeting minutes of the Station Nuclear Safety and Operating Committee.

The review of the independent review committee's meeting minutes revealed very little about the effectiveness of the committee, since only the agenda and any supporting handouts supplied by the presenters were maintained in the minutes. There was no mention of questions or concerns raised by the committee, how the committee tracked these concerns if any or whether or not the committee was able to raise concerns and effectively resolve them. Also, the meeting attended by the inspectors on May 18 did not shed any further light on the committee's effectiveness. During the meeting, there were several good presentations made by the licensee, but these presentations for the most part generated no in-depth questions or concerns. The inspectors were later informed that the meeting was not typical and that the inspector's presence had inhibited the committee's staff specialists.

The inspectors determined, based on discussions with licensee personnel and reviews of the committee's procedures, meeting minutes and reports, that the major problem was not the qualifications of the specific committee members, but rather a lack of resources dedicated to the committee functions. The TS requirements for a Director and three staff specialists were being complied with. However, the work load established by the TS could not be maintained effectively by a staff that size and to complicate the matter, the licensee assigned collateral duties for the Director and the specialists such that only a portion of their time was devoted to independent review. The inspectors were informed though, that the licensee was revising the entire program by increasing the committee's size from a Director and three staff-specialists to a Director and approximately 22 personnel located at both the sites and the corporate office, and by providing the requisite management attention to ensure proper implementation. This change in the program was based on a management consultant's review which informed licensee management that their independent review functions were not consistent with the rest of the industry.

Based on the above review, the inspectors determined that the corporate independent review group was not in full compliance with TS. For example, the committee does not conduct the required reviews as described in TS 6.5.2.7.a for safety evaluations relating to: a) changes to the plant through the EWR system, b) changes to procedures, and c) special tests. In addition, the committee does not review all SNSOC reports and meeting minutes as required by TS 6.5.2.7.g, and described in TS 6.5.2.7.a. Finally, the inspector determined that the corporate independent review group does not review all reportable events, violations, and special reports required by TS 6.5.2.7.d. Failure of the independent review group to conduct the required TS reviews will be identified as violation 338, 339/89-14-01.

In addition to the inadequate TS required review activities, the inspector also perceived a management attitude which possibly affected the poor performance of the review committee. There was the appearance that management either did not understand the TS requirements for the independent review group or was not being informed that the group was not properly performing its intended function. This perception was reinforced through discussions with several licensee personnel involved in the committee activities. Specifically, the Manager of Licensing stated that although the intent of the TS review may not have been met, the letter of the TS was being achieved. During this review, neither intent nor letter was noted to be achieved. The superficial committee review, as noted in the above violation, and the apparent compliance attitude observed during the inspection, raises a concern with the inspector over the licensee's management's past attitudes toward this committee's regulatory performance, and also the commitment of management to provide the support necessary to ensure the satisfactory implementation of the independent review function.

The inspector also attended several of the station's safety review committee (SNSOC) meetings and reviewed 14 committee meeting minutes for meetings conducted during 1988. Based on these reviews, the inspector concluded that the station safety committee was in compliance with TS. The only problems noted were a backlog of several months of the typed versions of the SNSOC meeting minutes and the volume of work placed on the safety committee. The majority of the items reviewed are procedure changes, indicating that the procedure upgrade process has not had the time to become effective in reducing the number of procedure changes required. The safety committee meets almost daily, fully complying with the TS required monthly meeting. The inspector has determined that the SNSOC has been effective in identifying problems and concerns, as evidenced by adequate reportability determinations for plant deviations, satisfactory 10 CFR 50.59 reviews, and properly evaluated JCOs.

The inspectors reviewed the station's nuclear safety engineering group's functions and effectiveness. This group, which works for the Assistant Station Manager for Safety and Licensing, provides an independent safety engineering function, the shift technical advisor function, the human performance evaluation function, the nuclear plant reliability data system function, deviation report tracking and trending, and operating experience review. This group performs independent evaluations at the station, which compensates to some extent for the incomplete reviews performed by the corporate independent review group. The inspector has observed an increase in the licensee's effectiveness in reviewing operating experience such as IEINs, 10 CFR 50.73 reports, station deviations and other activities. This group is also responsible for performing safety evaluations for EWRs, special tests, jumpers, JCOs, TS and UFSAR changes, and prior-to-use procedure deviations as well as independent review of safety related procedures and tests, design changes and changes to TS, at the discretion of the SNSOC chairman. The only problem identified by the inspector is that the resources devoted to the nuclear safety engineering group appear to be strained. The group's effectiveness could be increased by an increase in resources.

Along with the above assessment capabilities at the station, the station management has established a self assessment program. This program involves compiling, in one report, all of the information available at the station which would provide some insight on their performance. This report provides management with a tool to objectively assess the station's performance and determine where additional management attention is needed. The most recent self-assessment was performed in a SALP format.

Not only has the station management developed self-assessment capability for the station, but the recent restart of Unit 2 was preceded by a startup assessment. This assessment involved the superintendents of each department providing station management with a presentation and report concerning their areas of responsibility. These presentations and reports not only described the accomplishments of the groups, but focused on the items which were not completed and/or problems that had not been resolved. The presenter had to demonstrate why these items would not affect the restart of the unit or explain how they would be resolved prior to restart. The Unit 2 startup assessment provided station management with an objective tool to ensure all items, problems or concerns were addressed, properly reviewed, corrected or accepted prior to restart. The startup assessment is new, but the inspector was impressed with the program, the candidness of the presentations, and the desire by station management to be fully informed of all problems and concerns so that a well informed decision to restart the unit could be made.

15. Exit

The inspection scope and findings were summarized on May 31, 1989, with those persons indicated in paragraph 1. Violation 338,339/89-14-01 was also discussed with the Manager of Licensing on May 18, 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 received from the licensee at the May 18, 1989 exit as discussed in paragraph 14.

Violation 338,339/89-14-01, Failure of the licensee's independent review group to perform all of the reviews required by Technical Specifications (paragraph 14).

Violation 338,339/89-14-02, Failure of procedures to control maintenance operations with two examples (paragraphs 7 and 9).

Violation 338,339/89-14-03, Failure of the procedures to adequately control the location of fuel assemblies during fuel movement operations (paragraph 9).

Apparent Violation 338,339/89-08-03, An additional example of failure to provide design basis SW flow to the safety-related RSHX (paragraph 5).

Non-Cited Violation 338,339/89-14-04, Failure to comply with TS 3.11.1.3 and issue the special report in the required 30 day period (paragraph 7).

Inspector Follow-up Item 338,339/89-14-05, Review documentation to support power supply modification of SLV Relays (paragraph 12).

16. Acronyms and Initialisms

AP	Abnormal Procedure
CAD	Computer Assisted Drawing
CAE	Condenser Air Ejector
CDA	Containment Depressurization Actuation
CPU	Central Processing Unit
CRO	Control Room Operator
CVCS	Chemical Volume and Control System
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
FAI	Fuel Audit and Inspection
FHDS	Fuel Handling Data Sheet
GPM	Gallons Per Minute
HP	Health Physics
IFI	Inspector Follow-up Item
IST	Inservice Testing
JCO	Justification for Continued Operations
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MCC	Motor Control Center
MFRV	Main Feedwater Regulatory Valve
MOV	Motor Operated Valve
MPC	Maximum Permissible Concentration
MREM	Millirem
MSRC	Management Safety Review Committee
MSSV	Main Steam Safety Valve
MSVH	Main Steam Valve House
NA	Not Applicable
NCV	Non-Cited Violation
NIS	Nuclear Instrumentation System
NRC	Nuclear Regulatory Commission
NSE	Nuclear Safety Engineering
PDTT	Primary Drain Transfer Tank
PES	Plant Engineering Services
PM	Preventative Maintenance
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
RSHX	Recirculation Spray Heat Exchanger
RTD	Resistance Temperature Detector

RWP	Radiation Work Permit
SG	Steam Generator
SALP	Systematic Assessment of Licensee Performance
SF/FF	Steam Flow/Feedwater Flow
SI	Safety Injection
SNSOC	Station Nuclear Safety and Operating Committee
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
SW	Service Water
TS	Technical Specification
TSC	Technical Support Center
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VCT	Volume Control Tank
WOG	Westinghouse Owners Group