UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

October 21, 2004

Virginia Electric and Power Company
ATTN.: Mr. David A. Christian
Sr. Vice President and
Chief Nuclear Officer
Innsbrook Technical Center - 2SW
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: NORTH ANNA POWER STATION - NRC INTEGRATED INSPECTION REPORT NO. 05000338/2004005, 05000339/2004005 AND 07200016/2004002

Dear Mr. Christian:

On September 25, 2004, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your North Anna Power Station, Units 1 and 2, and the North Anna Independent Spent Fuel Storage Installation. The enclosed integrated inspection report documents the inspection findings, which were discussed on August 18, 2004, and on October 5, 2004, with Mr. Jack Davis and other members of your staff.

The inspections examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one NRC-identified finding. The finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because the violation was entered into your corrective action program, the NRC is treating the finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, three licensee-identified violations which were determined to be of very low safety significance (Green) are listed in Section 4OA7 of this report. If you contest any non-cited violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the North Anna Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, it's enclosure, and your response (if any), will be available electronically for public inspection in the

NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at *http://www.nrc.gov/reading-rm/adams.html* (the Public Electronic Reading Room).

Sincerely,

/RA/

Kerry D. Landis, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket Nos.: 50-338, 50-339, 72-016
License Nos.: NPF-4, NPF-7, SNM-2507

Enclosures: Inspection Reports 05000338/2004005, 05000339/2004005 and 07200016/2004002 w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.: 50-338, 50-339, 72-106

License Nos.: NPF-4, NPF-7, SNM-2507

Report Nos.: 05000338/2004005, 05000339/2004005, 07200016/2004002

Licensee: Virginia Electric and Power Company (VEPCO)

Facilities: North Anna Power Station, Units 1 & 2
North Anna Independent Spent Fuel Storage Installation

Location: 1022 Haley Drive
Mineral, Virginia 23117

Dates: June 27, 2004 - September 25, 2004

Inspectors: M. Widmann, Senior Resident Inspector
G. Warnick, Acting Senior Resident Inspector
G. Wilson, Resident Inspector
L. Garner, Senior Project Engineer
R. Chou, Reactor Inspector (Section 4OA5.3)
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L. Miller, Nuclear Safety Professional (Sections 1R08, 4OA5.4)

Approved by: K. Landis, Chief, Reactor Projects Branch 5
Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000338/2004-005, IR 05000339/2004-005, IR 07200016/2004-002; 06/27/2004 - 09/25/2004; North Anna Power Station Units 1 & 2 and Independent Spent Fuel Storage Installation; Problem Identification and Resolution.

The report covered a three month period of inspection by resident inspectors, senior project engineer, announced inspections by two senior reactor inspectors in the area of inservice inspection, one reactor inspector in the area of vessel head examinations, and two emergency preparedness inspectors. One Green non-cited violation (NCV) and three licensee identified violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Finding

Cornerstone: Mitigating Systems

- Green. An NRC-Identified Non-Cited Violation was identified for failure to take appropriate corrective actions to preclude the recurrence of a significant condition adverse to quality as required by 10 CFR 50 Appendix B Criterion XVI. Corrective actions taken in 2003 for an improperly installed snubber failed to include actions to inspect for additional snubbers which were installed with an incorrect offset. As a result three additional snubbers where identified in 2004 which were installed with incorrect offsets. The licensee also had a potential opportunity to identify this condition during the Spring 2003 refueling outage visual inspections of these snubbers.

  This finding is more than minor because it adversely impacted the reactor safety mitigating system cornerstone objective, in that, protection against external factors such as seismic events are needed to ensure the availability, reliability and capability of the reactor coolant system. The finding was determined to have very low safety significance because the snubbers remained operable. This finding involved the cross-cutting aspect of Problem Identification and Resolution. (Section 4OA2.2)

B. Licensee-Identified Violations

Three violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status

Unit 1 began the inspection period at 100% power, but commenced a shutdown for refueling on September 12, 2004. At the end of the inspection period the unit was in Mode 6 with core re-load in progress. Unit 2 began the inspection period at 100% power and remained at this power for the reporting period except for small power reductions to perform periodic testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Due to heavy rain fall from Tropical Storm Gaston on August 30 and 31, 2004, which produced spot flooding, the inspectors performed a walkdown of outside areas including equipment access wall and floor plugs for in-leakage. The inspectors also performed a walkdown of the Emergency Core Cooling System (ECCS) equipment areas.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope - Partial System Walkdowns

The inspectors performed the following three partial system walkdowns during this inspection period. The walkdowns were to evaluate the operability of the selected train or system when the redundant train or system was inoperable or out of service. The inspectors checked for correct valve and power alignments by comparing the positions of valves, switches, and electrical power breakers to that of procedures and drawings.

- Unit 1 Train B Low Head Safety Injection System (1-OP-7.1A, “Low Head Safety Injection Valve Checkoff Sheet);”
- Unit 2 Component Cooling Water Subsystem 1A (0-PT-74.1, “Component Cooling Water Subsystem - Valves (Monthly);” and,
- Unit 2 Train A Low Head Safety Injection System, while B Train was removed from service for surveillance testing.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors assessed the implementation of the fire protection program using Virginia Power Administrative Procedure VPAP-2401, "Fire Protection Program." The inspectors checked the control of transient combustibles and the material condition of the fire detection and fire suppression systems in the following eleven areas:

- Service Water Pump House (fire zone 12a/SWPH);
- Emergency Diesel Generator 1H and 1J Unit 1 (fire zones 9A-1a/EDG-1H and 9B-1a/EDG-1J) and Emergency Diesel Generator 2H and 2J Unit 2 (fire zones 9A-2a/EDG-2h and 9B-2a/EDG-2J);
- Charging Pump Cubicles 1-1A, 1-1B, 1-1C, 2-1A, 2-1B, 2-1C (fire zones 11Aa/CPC-1A, 11Ba/CPC-1B, 11Ca/CPC-1C, 11Da/CPC-2A, 11Ea/CPC-2B, 11Fa/CPC-2C);
- Turbine-Driven Auxiliary Feedwater Pump Room Unit 1 and Unit 2 (fire zones14A-1a/TDAFW-1 and 14A-2a/TDAFW-2) and Motor-Driven Auxiliary Feedwater Pump Room Unit 1 and Unit 2 (fire zones 14B-1a/MDAFW-1 and 14B-2a/MDAFW-2);
- Fuel Building (fire zone Z-18/MGSH-1);
- Battery Room 1 - II Unit 1 (fire zone 7B-1/BR1-II), Battery Room 2 - II Unit 2 (fire zone 7B-2/BR2-II), Technical Support Center Battery Room (fire zone 46B/TSCBR);
- Cable Vault and Tunnel, Units 1 and 2,including Control Rod Drive Rooms and Z-27-1, Z-27-2 (fire zones 3-1a/CV & T-1 and 3-2a/CV & T-2);
- Unit 1 and 2 Control Rooms (fire zone 2.a/CR);
- Unit 1 Charcoal Filter Exhaust Plenum;
- Quench Spray Pump House and Safeguards Area Unit 2 (includes Z-16-2 and fire zone 15-2a/QSPH-2); and,
- Containment Unit 1 (fire zone 1-1a/RC-1).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope (External Flooding)

The inspectors assessed the external flooding vulnerability of the safeguards and quench spray buildings, associated pump cubicles and piping tunnels due to the seasonal heavy rains and recent hurricanes. The inspectors verified that removable ceiling-mounted equipment hatch plugs were properly sealed or covered to address possible water in-leakage and flooding of safety-related components. Building and cubicle sump pump maintenance history were reviewed to verify that pumps were fully functional and available.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

a. Inspection Scope

ISI Activities

The inspectors observed in-process ISI work activities, reviewed ISI procedures, and reviewed selected ISI records, associated with risk significant structures, systems, and components. The observations and records were compared to the requirements specified in the Technical Specifications (TS) and the ASME Boiler and Pressure Vessel Code, to verify compliance and to ensure that examination results were appropriately evaluated and dispositioned.

Specifically, non-destructive examination (NDE) activities were reviewed as follows:

- Ultrasonic Examination (UT) of the pressurizer nozzle-to-safe-end weld for the “A” safety-valve piping;
- UT examination of Low-Head Safety Injection system welds 20, 38, 84, and 86; and,
- Visual Examination (VT) of pressurizer relief and safety valve piping, nozzle-to-safe-end, and safe-end-to-piping, welds.

UT instrument and examination calibration records, and UT examination personnel qualification records were reviewed for compliance with ASME code requirements.

The inspectors reviewed the documentation package for the replacement of a section of Low-Head Safety Injection piping due to a through-wall leak at weld number 28. The documentation reviewed included the repair/replacement plan work order, welding and non-destructive examination records, material certifications, and related procedures. The inspectors also reviewed the final root cause evaluation report for the through-wall leak.

Reactor Vessel Head Inspection

The inspectors reviewed reactor vessel head examination activities to determine if examinations of nozzle penetrations were being conducted in accordance with NRC Order EA-03-009, and that indications or defects were dispositioned in accordance with the ASME Code or an NRC approved alternative. The licensee performed the inspections under the following procedures and program documents: DNAP-1004, “Boric Acid Corrosion Control (BACC) Program,” Rev. 2; NASES-6.23, “Boric Acid Corrosion Control (BACC) Program,” Rev. 1; and 1-PT-48.5, “ Leakage Inspection Above Reactor Vessel Head,” Rev. 0. The inspectors reviewed the licensee’s actions following Framatome's insulation clearance visual inspection of the reactor vessel head which found white, dry boric acid residue at penetration #53, which is the core exit thermocouple nozzle assembly connection. The inspectors reviewed the results of the smear sample analyzed in the multichannel analyzer which identified no short-lived nuclides, supporting the conclusion this acid is not from a recent leak. The inspectors also reviewed a small area on the carbon steel head which was identified as having some small pitting indications.

Boric Acid Corrosion Control (BACC) Inspection

The inspectors reviewed implementation of the licensee's BACC program to determine if commitments made in response to Generic Letter 88-05 and Bulletin 2002-01 were being effectively implemented. The inspectors conducted a walk-through inspection of the containment to observe the as-found indications of borated water leakage.

During containment entries, the inspectors observed the conduct of licensee BACC inspection activities in order to evaluate the thoroughness of the inspections. The inspectors reviewed licensee Plant Issue Report Nos. –2004-3536 and –2004-3537, documenting findings of the licensee's BACC inspections and compared those results with observations noted during the inspectors' containment walk-through inspections.

Engineering evaluations of BACC inspection findings from the Spring 2004 Unit 2 outage were reviewed to evaluate the engineering bases for conclusions regarding apparent cause and severity of discovered leaks, and justification for corrective actions. Engineering evaluations reviewed were: N-2004-1454-E1, N-2004-1520-E1, and N-2004-1691-E1.

Steam Generator (SG) Inspection

The inspectors reviewed activities, plans, and procedures for the examination and evaluation of steam generator tubing (primary side) and steam generator secondary side inspections to determine if activities were being conducted in accordance with TS and applicable industry standards.

Specifically, the inspectors observed and reviewed the following SG eddy current testing (ECT) examination activities: (1) Bobbin and Plus Point data acquisition for a sample of SG tubes in the 'C' SG. (2) Licensee SG inspection requirements relative to: in-situ pressure test criteria, ECT scope and expansion criteria, plugging limits and repair criteria, appropriateness of ECT equipment for expected types of degradation, and corrective actions for loose parts.

The inspectors reviewed the examination scope, which was a 100% full length bobbin exam (except row 1, straight length only), Row 1 U-bend with Plus Point, 20% of top of tube sheet H/L, 100% identified as 'Critical Area (CA)' tubes, and a systematic pattern of the balance of unexamined tubes outside of the critical area with Plus Point.

The inspectors reviewed one sample of ECT data for the tube with wear indications and their disposition and corrective action. The inspectors reviewed the licensee's determination that the wear was caused by a loose part (wire), which was removed and the tube plugged after further analysis was performed (Plus Point). The inspectors reviewed the results of the visual examination (VT) of the secondary side, where the licensee found additional loose parts on the top of tube sheet and above the 7^{th} support plate, which were removed and evaluated to determine if any collateral damage was done to any adjacent tubes. The inspectors discussed their evaluation and proposed corrective actions.

The inspectors reviewed corrective action items associated with the SG ISI program to determine if problems were being identified at appropriate thresholds and if adequate corrective actions were being taken. The inspectors reviewed to determine that the issues identified during the SG ISI outage, discussed above, were entered into the corrective action program and that the proposed corrective actions were appropriate.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed licensed operator simulator training on August 24, 2004. The scenario, Simulator Examination Guide SXG-66, involved a failed pressurizer channel, a broken charging pump shaft and a steam generator tube leak (> 100 gpd) that evolved to a tube rupture > 500 gpm. The inspectors observed crew performance in terms of communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS actions. The inspectors observed the post training critique to determine that weaknesses or improvement areas revealed by the training were captured by the instructors and reviewed with the operators.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

For the two equipment issues listed below, the inspectors evaluated the licensee's effectiveness of the corresponding preventive and corrective maintenance. The inspectors performed walkdowns of the accessible portions of the systems, performed in-office reviews of procedures and evaluations, and held discussions with system engineers. The inspectors compared the licensee's actions with the requirements of the Maintenance Rule (10 CFR 50.65) using VPAP 0815, "Maintenance Rule Program," and Engineering Transmittal CEP-97-0018, "North Anna Maintenance Rule Scoping and Performance Criteria Matrix." Additionally, the inspectors attended some of the licensee's scheduled Maintenance Rule Working Group meetings.

- Plant Issue –2004-2385, Control Room to Turbine Building differential pressure problem; and,
- Emergency Diesel Generator (EDG) reliability issues and new maintenance practice to feed and bleed glycol/water mixture for changing of seasons (summer to winter) 2-MOP-6.94 and ET-–03-0164.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed data output from the licensee's safety monitor associated with the risk profile of Units 1 and 2, attended pre-job briefs, and held discussions with licensee personnel. The following six emergent work items were inspected:

- Replacement of the Unit 2 Blender Makeup Mode Selector Switch per Work Order (WO) 0514919;
- Unit 1 Low Head Safety Injection Pump Suction Piping repairs and associated emergency technical specification amendment request;
- Performance of Unit 2 trains A and B Solid State Protection System Output Slave Relay testing per 2-PT-36.5.3.A(B) for associated risk assessment;
- Swapping of Unit 2 power supplies for 'B' semi-vital bus and U1-Hydrogen Analyzer with 1-CH-P-1C pump removed from service for rotating element replacement and switchyard control room ventilation work in progress;
- Unit 2 CH-P-1C speed increaser low differential pressure and 1-RS-P-1A seal head tank inoperable while 2-H-EDG, 1-CH-P-2B, 1-CW-TV-100 and switchyard maintenance activities in progress; and,
- Assessed shut down risk associated with Unit 1 in Mode 5 with maintenance activities on 1H EDG Blackout test and switchyard work on Unit 1 "A" station service bus.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Evolutions and Events

a. Inspection Scope

The inspectors monitored the response of Unit 2 control room operators during the period of August 28 through 30, 2004, when the Unit 2 Steam Generator ‘B’ level channel lo-lo annunciator actuated spuriously causing multiple entries into 2-AP-3 that required operator action to take manual control of main feedwater regulating valves.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors conducted reviews and held discussions with the appropriate licensee engineers, managers and operations personnel for the five operability determinations addressed in the plant issues listed below. The inspectors assessed the accuracy of the evaluations, the use and control of compensatory measures, and compliance with TS. The inspectors’ review included a verification that the operability determinations were made as specified by Procedure VPAP-1408, “System Operability.” The technical adequacy of the determinations was reviewed and compared to Technical Specifications, the Technical Requirements Manual and the Updated Final Safety Analysis Report (UFSAR).

- –2004-2526, operability assessment for 2-SW-MOV-201A and 2-SW-MOV-201B (ET-04-0051);
- –2004-2457, Unit 2 blender mode selector switch left in the “MANUAL” position due to inability to physically move the switch back to the “AUTO” position;
- –2004-2981, 2J EDG CO_2 System Operability impact with air intake louvers stuck open;
- –2004-3231, 1-CH-P-1A Charging Pump outboard seal leakage determined to be degraded, but operable; and,
- –2004-1037, 1-SW-P-1A Motor O-ring failure rendered pump inoperable with extent of condition under review.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following six post-maintenance test (PMT) procedures, WOs, Plant Issues, and activities associated with the repair or replacement of the following components to determine that the procedures and test activities were adequate to verify operability and functional capability of the equipment:

- Procedure 2-OP-7.4, “Recirculation of RWST Using QS Pumps,” valve 02-QS-25 external leakage test and valve stroke per WO 0513986, tasks 1 and 2;
- Procedure 1-PT-57.1A, “Emergency Cooling Subsystem Low Head Safety Injection Pump 1-S1-P-1A,” per WO 0515656, tasks 1 and 3;
- Procedure 2-PT-14.3, “Charging Pump 2-CH-P-1C,” per WO 0496371, due to leakage from outboard and inboard seals;
- Procedure 1-PT-213.5H, “Valve Inservice Inspection 1-QS-MOV-100A,” per WO 0508464;
- PMT 2-PT-57.1B, “ECCS-LHSI Pump (2-S1-P-1B),” per WO 0168482 on 1B Low Head Safety Injection Pump to loop hot leg relief valve 2-SI-RV-2845C due to rebuild; and,
- Procedure ICP-N1-1-–32, Rev. 15, “Source Range Channel –32," and 1-PT-30.4.2, “Source Range Channel –32 Calibration,” per WOs 0507248 and 0507249.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

For the six surveillance tests listed below, the inspectors examined the test procedure and witnessed testing, and reviewed test records and data packages, to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable, and that the surveillance requirements of the technical specifications were met:

- 1-PT-52.2A, “Reactor Coolant System Leak Rate (Computer Calculation);”
- 1-PT-75.2A, “Service Water Pump (1-SW-P-1A) Quarterly Test;”
- 0-PT-76.3, “Control Room Bottled Air Pressurization System;”
- 1-PT-71.15, “Loss of Offsite Power - Train B Operational Test for Auxiliary Feedwater Pumps,” and 1-PT-71.2Q, “A Motor Driven A.W. Pump and Valve Test;”
- 1-PT-36.1A, “Train “A” Reactor Protection and EHC Logic Actuation Logic Test;” and,

- 2-PT-57.1B, “Emergency Core Cooling Subsystem - Low Head Safety Injection Pump (2-SI-P-1B).”

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed a temporary plant modification to verify that the modification did not affect system operability or availability as described by the TS and UFSAR. The temporary modification lifted leads temporarily to defeat the EDG low jacket coolant keep warm system temperature switches during warm weather conditions in accordance with procedure 0-GOP-5.5, “EDG Hot Weather Operations,” and VPAP-1403, “Temporary Modifications.” The inspectors verified that the installation of the temporary modification was in accordance with the work package, that adequate control was in place, procedures and drawings were updated, and post-installation tests verified the operability of the affected systems.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation

a. Inspection Scope

The inspectors reviewed the scenario and emergency exercise for the biennial 2004 emergency response exercise for North Anna as required by Section IV.F.2.c of Appendix E to 10 CFR Part 50. The review assessed whether the licensee created a scenario suitable to test the major emergency plan elements in accordance with Appendix E to 10 CFR Part 50.

Licensee activities inspected during the exercise included independent observations in the Control Room Simulator, Local Emergency Operations Facility, Technical Support Center, and Operations Support Center. The exercise was conducted on July 20, 2004. The inspectors reviewed a sample of corrective actions, and determined whether performance trends represented a failure to: correct weaknesses, meet planning standards or meet other regulatory requirements. The inspectors developed a list of performance areas to be observed in this exercise. The inspectors’ evaluation focused on the risk-significant activities of event classification, notification of governmental authorities, onsite protective actions, offsite protective action recommendations, and accident mitigation. The inspectors also evaluated command and control, the transfer of emergency responsibilities between facilities, communications, adherence to procedures, and the overall implementation of the emergency plan. The inspectors attended the post-exercise critique to evaluate (1) the licensee's self-assessment process and (2) the presentation of critique results to plant management.

At the conclusion of these evaluations and independent observations, the inspectors determined whether the exercise was a satisfactory test of the Emergency Plan and whether the licensee's response to the simulated emergency conditions met the requirements of 10 CFR 50.47(b).

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

The inspectors reviewed all emergency action level changes against the requirements of 10 CFR 50.54(q) to determine whether they had not decreased the effectiveness of the Radiological Emergency Plan. The licensee had implemented Radiological Emergency Plan Revisions 28 and 29, including modifications to the emergency action levels (EAL) basis descriptions and the removal of two EALs for low water level and flooding. The change for these EALs had been approved by NRC Safety Evaluation Report dated October 20, 2003. The inspectors conducted a detailed review of all emergency action level basis changes. The inspectors reviewed documentation of the licensee's 10 CFR 50.54(q) screening evaluations for the referenced revisions.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Initiating Events and Barrier Integrity Cornerstones

a. Inspection Scope

The inspectors performed a periodic review of the Unit 1 and 2 PI data reported to the NRC for the following PIs:

- Unplanned Scrams;
- Scrams with Loss of Normal Heat Removal; and,
- Reactor Coolant System Activity.

The inspectors reviewed data from the licensee's corrective action program, maintenance rule records, operating logs and maintenance work orders for the period covering the third quarter 2003 through the second quarter 2004. Discussions with licensee personnel were held by the inspectors regarding the data reviewed. The data was compared with that displayed on the NRC's public web site. The performance indicator method of assessment was compared with the guidelines contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline."

During plant tours the inspectors also periodically assessed the Occupational Exposure Control Effectiveness and the RETS/ODCM Radiological Effluent Occurrence Performance Indicators by determining if high radiation areas (>1R/hr) were properly secured, and looking for unmonitored radiation release pathways.

b. Findings

No findings of significance were identified.

.2 Emergency Preparedness Cornerstone

a. Inspection Scope

The inspectors sampled licensee submittals relative to the PIs listed below for the period July 2003 through June 2004. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2, were used to confirm the reporting basis for each data element.

- Drill/Exercise Performance
- Emergency Response Organization Drill Participation
- Alert and Notification System Reliability

For the specified review period, the inspectors examined data reported to the NRC, procedural guidance for reporting PI information, and records used by the licensee to identify potential PI occurrences. The inspectors verified the accuracy of the PI for Emergency Response Organization (ERO) drill and exercise performance through review of a sample of drill and event records. The inspectors reviewed selected training records to verify the accuracy of the PI for ERO drill participation for personnel assigned to key positions in the ERO. The inspectors verified the accuracy of the PI for alert and notification system reliability through review of a sample of the licensee's records of periodic system tests. The inspectors also interviewed the licensee personnel who were responsible for collecting and evaluating the PI data. Licensee procedures, records, and other documents reviewed within this inspection area are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Routine Focus Review - Solid State Testing

a. Inspection Scope

The inspectors selected two plant issues for a detailed review (Plant Issues –2004-2234 and –2004-2825). The two corrective action documents pertain to test personnel actuating incorrect push-buttons due to human performance errors while performing solid state protection testing. The inspectors performed this evaluation to identify similarities, if any, between the causes of the two events. The plant issues were reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the plant issues against the requirements of the licensee's corrective action program as described in Administrative Procedure VPAP-1601, "Corrective Action," Revision 19. Additionally, the inspectors observed portions of two surveillance, 2-PT-36.1A, "Train A Reactor Protection and EHC Logic Actuation Logic Test," and 2-PT-36.5.3A, "Solid State Protection System Output Slave Relay Test (Train A)," to evaluate the effectiveness of corrective actions taken.

b. Findings

There were no findings of significance identified. The inspectors determined that the cause evaluations and associated corrective actions were appropriate and also timely, relative to the identified problems.

.2 Routine Focus Review - Snubber Installations

a. Inspection Scope

The inspectors reviewed Plant Issue –2003-1160 issued in 2003 involving an improperly installed snubber to verify whether corrective actions taken were comprehensive. This review was conducted because, the inspectors identified two improperly installed snubbers on the Reactor Coolant System (RCS) on September 21, 2004.

b. Findings

Introduction. A Green NRC-Identified Non-Cited Violation (NCV) was identified for failure to take appropriate corrective actions to preclude the recurrence of a significant condition adverse to quality as required by 10 CFR 50 Appendix B Criterion XVI. Corrective actions taken in 2003 for an improperly installed snubber failed to include actions to inspect for additional snubbers which were installed with an incorrect offset. As a result three additional snubbers where identified in 2004 which were installed with incorrect offsets. The licensee also had a potential opportunity to identify this condition during the Spring 2003 refueling outage visual inspections of these snubbers.

<u>Description</u>. In 2003, NRC Inspection Report 050000338/2003002 documented an NRC-identified NCV involving snubber, 1-SI-HSS-107, not being installed in accordance with station drawings. Several conditions adverse to quality were identified with this snubber's installation and documented in Plant Issue –2003-1160. The corrective action associated with this issue was to inspect a sample of snubbers for similar conditions. However, the licensee failed to adequately include one of the adverse conditions in the inspection. This was associated with the angle (the offset) at which the snubber was installed.

On September 21, 2004, during a containment walkdown, the inspectors identified hydraulic snubbers, 1-RC-HSS-827 and 1-RC-HSS-829, that were not installed per the design drawings. The snubbers were installed on the “C” RCS loop drain line. The offset was approximately one inch greater than the 2.5 inches shown on Drawings 11715-PSSK-103BB.27 and 11715-PSSK-103BB.30. The licensee issued Plant Issue –2004-3938 for this condition. The licensee subsequently performed additional walkdowns in containment to evaluate other installed snubber conditions. The results, documented in Plant Issue –2004-3937, included snubber 1-RC-HSS-839 with installation deficiencies. The conditions were significant conditions adverse to quality, in that, improper installation would have contributed to a snubber capacity reduction and challenged its ability to perform it intended function to resist the shock loads during seismic or transient conditions.

The immediate corrective actions included WOs to return the snubbers to the correct configuration per the design drawings and to perform a past operability evaluation. Initial analysis of the as-found condition of 1-RC-HSS-839 support determined that it did not meet its required design parameters. Subsequent past operability evaluations for the three non-conforming snubbers determined that the snubber operability was not adversely impacted by the incorrect installation.

The licensee had a potential prior opportunity to discover these conditions. Engineering inspection procedure 1-PT-79.7, “Visual inspection of Unit Hydraulic Snubbers,” completed by the licensee on April 8, 2003, performed a 100 percent walkdown of the Unit 1 containment snubbers. Although the as-found installation deficiencies existed at the time of the 2003 inspection, the visual inspection failed to identify the discrepancies with the installation of these three snubbers.

<u>Analysis</u>. This finding is more than minor because it adversely impacted the reactor safety mitigating system cornerstone objective, in that, protection against external factors such as seismic events are needed to ensure the availability, reliability and capability of the RCS. The snubbers being installed improperly challenged their ability to mitigate the impact of a seismic event on the piping system. Using the Significance Determination Process Phase 1 Worksheet, the finding was determined to have very low safety significance because the snubbers were determined to be operable. This finding involved the cross-cutting aspect of Problem Identification and Resolution.

<u>Enforcement</u>. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action", in part, requires that measures shall be established to assure that conditions adverse to quality,

such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the licensee failed to preclude repetition of significant conditions adverse to quality, in that, in September 2004 three hydraulic snubbers were found with installation deficiencies similar to those found with a snubber in 2003. Because the failure to preclude the incorrect installation of snubbers was of very low safety significance and the licensee documented this condition in their corrective action program, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000338/2004005-01, Failure to Adequately Prevent the Improper Installation of Three Hydraulic Snubber Supports.

4OA3 Event Followup 71153

.1 Low Head Safety Injection Leak

a. Inspection Scope

The inspectors evaluated plant operations, equipment performance, and licensee actions related to the identification and repair of a through wall leak on the "A" Low Head Safety Injection pump suction. (Also reference Section 1R08 of this report for additional review of this item).

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report (LER) 05000338, 339/2003005-00: Inoperable Hydrogen Recombiner Due to Inadequate Work Practices

On November 10, 2003, during testing of the hydrogen recombiner, 2-HC-HC-1, the licensee determined that the low and high side isolation valves were improperly positioned (i.e., closed) causing the unit to trip on low flow. The two valves were determined to have been in the incorrect position since completion of the previous surveillance test in August 2003. The cause of the mis-positioning was determined to be inadequate work practices, in that, documents were not followed properly. Immediate corrective actions were taken to open the two isolation valves and return the hydrogen recombiner to operable status. Additional corrective actions included development of departmental instructions and lesson plans for instrument and controls technicians to manipulate instrument valves. This finding is more than minor because it affects the configuration control attribute for operating equipment lineup. In this configuration the recombiner would be unable to perform its safety function. This finding affects the Mitigating Systems Cornerstone and was considered to have very low safety significance (Green) using Appendix A of the Significance Determination Process (SDP) because the opposite train's hydrogen recombiner was available. This licensee-identified finding involved a violation of Technical Specification (TS) 3.6.9, "Hydrogen

Recombiners." The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.3 (Closed) LER 05000339/2004002-00: Manual Reactor Trip Due to Control Bank “D” Group Step Counter Inoperable

On May 29, 2004, a manual reactor trip was initiated as result of control bank “D” group demand position indicators being inoperable. A mismatch of the control bank “D” Group 1 and 2 demand position indicator greater than two steps occurred due to the demand position indicator cover not being snapped down, causing the mechanical cams to not be properly engaged. The improper condition of the demand position indicator cover was attributed to maintenance work practices following a previous adjustment. Licensee corrective actions included revision to a rod drop test procedure, enhancement to operator training, instrument and control technicians and reactor engineering personnel, and development of a training information bulletin regarding the demand step counter cover. This finding is more than minor because it can be reasonably viewed as a precursor to a significant event (i.e., reactor trip). This finding affects the Initiating Events Cornerstone and was considered to have very low safety significance (Green) using Appendix A of the SDP because the reactor was subcritical at the time of the event. This licensee-identified finding involved a violation of TS 5.4.1, "Procedures." The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.4 (Closed) LER 05000339/2004003-00: Inoperable Containment Personnel Lock Resulting in Missed Surveillance.

On June 6, 2004, the outer containment personnel air lock was determined to be inoperable due to the outside door not being properly closed. The improperly closed door was discovered during a leakage surveillance test. The licensee had last been in containment two days earlier, but failed to lock-close the door in accordance with station procedures. The cause of the failure was determined to be due to human error and inadequate procedure instructions to accurately delineate the details for proper closed position of the air lock door. License corrective actions included revising the procedure for closure of the door, independent verification of that action, and labeling on the air lock door to better identify the door position. This finding is more than minor because it had a credible impact on safety, in that, if the redundant interior door was not closed properly or had the seal failed then containment integrity would not be assured. The finding affects the Barrier Integrity Cornerstone and was considered to have very low safety significance (Green) using Appendix H of the SDP, because the likelihood of an accident leading to core damage was not affected, the redundant interior door remained operable, containment was operating under vacuum, and no leakage escaped to the atmosphere. This licensee-identified finding involved a violation of TS 3.6.2, "Containment Air Locks." The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

.5 (Closed) LER 05000339/2004004-00, Reactor Trip Due to Incorrect Cell Switch Contact Configuration on Bypass Reactor Trip Breaker

On June 10, 2004, an automatic Unit 2 reactor trip occurred during the performance of 2-PT-36.1A, “Train A Reactor Protection and ESF Logic Actuation Logic Test.” The inspectors reviewed this event and documented the results in NRC Inspection Report 05000339/2004003, Section1R14, and identified NCV 05000339/2004003-03, “Reactor Trip due to Improper Cell Switch Installation.” The LER was reviewed by the inspectors and no new findings were identified. The licensee documented the event in Plant Issue –2004-2301. This LER is closed.

4OA5 Other Activities

.1 Review of the Operation of an Independent Spent Fuel Storage Installation (60855)

a. Inspection Scope

Inspectors reviewed the normal operations of the Independent Spent Fuel Storage Installation (ISFSI). Inspectors verified through a review of selected records that the licensee has properly identified each fuel assembly placed in the latest cask which has been placed on the ISFSI pad. Additionally, the inspectors selected random cask records to verify quality and completeness and that records were kept as controlled documents, and that the licensee has recorded the parameters and characteristics of each fuel assembly loaded. Inspectors also verified that the fuel placed in these casks met the requirements of the technical specifications. Inspectors also walked down both ISFSI pads to assess the material condition of the casks, the installation of security equipment, and the performance of the monitoring systems. Inspectors verified that the required records are being retained for the ISFSI pad and duplicate records are being kept at a separate location. However, the inspectors noted that the licensee has an license exemption to the duplication of records requirements, but has voluntarily chosen to maintain both an electronic version and a hard copy in a separate location.

b. Findings

No findings of significance were identified.

.2 (Closed) NRC Temporary Instruction (TI) 2515/152, Revision 1, “Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02)” - Unit 1

a. Inspection Scope

The inspectors observed activities relative to inspection of the Unit 1 reactor pressure vessel (RPV) lower head penetrations in response to NRC Bulletin 2003-02. The guidelines and criteria for the inspection were provided in NRC TI 2515/152, “Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02).” The inspectors observed the licensee’s examiners perform the visual examination of the welds on the nozzles for boric acid leaks and cracks. The inspectors also independently examined the nozzles. The inspectors discussed the process and the results with the licensee’s examiners for the liquid penetrant examination (PT) performed on a weld suspected to have boric acid deposit. The inspectors reviewed the chemical laboratory test result for the deposit, and qualification and certification for the VT-2 visual examiners and PT examiners.

b. Findings

No findings of significance were identified. Specific questions contained within the TI are discussed below.

1. For each of the examination methods used during the outage, was the examination:

   a. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

      The examination was performed by qualified and knowledgeable individuals that were qualified as Level II non-destructive VT-2 examiners. PT was also performed by qualified Level II examiners.

   b. Performed in accordance with demonstrated procedures?

      The examination was performed per Engineering Periodic Test procedure 1-PT-48.4, Revision 1, “Bare Metal Inspection of Vessel BMI Nozzles.” The inspectors also reviewed VPAP-1103, “ASME Section XI Visual Examination Program (VT-1,2,3 & General),” which was the governing procedure for the ASME requirements for performing the reactor vessel bottom head inspection. Performance of the visual VT-2 examination was conducted in accordance with established procedures.

   c. Able to identify, disposition, and resolve deficiencies?

      The examination was completed by direct visual examination. The inspectors also independently examined the welds for leaks and cracks. Procedure 1-PT-48.4 established criteria to identify, disposition, and resolve deficiencies on a case-by-case basis.

   d. Capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

      The examination was capable of identifying pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion.

2. Could small boric acid deposits representing RCS leakage, as described in the Bulletin 2003-02, be identified and characterized, if present, by the visual examination method used?

   The examination was adequate to satisfy the Bulletin requirements.

3. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

   The examination was conducted via direct visual by the examination personnel.

4. How complete was the coverage (e.g., 360E around the circumference of all the nozzles)?

   The examiners and inspectors could observe 360E around each nozzle due to the removal of the insulation. No obstruction was presented.

5. What was the physical condition of the RPV lower head (e.g., debris, insulation, dirt, deposits from other sources, physical layout, viewing obstructions)? Did it appear that there are any boric acid deposits at the interface between the vessel and the penetrations?

   The general physical condition of the RPV lower head area was generally clean with no indications of boric acid deposits at the vessel/BMI interface. Some minor surface corrosion was due to reactor cavity seal leaks several years ago. There were no obstructions or obstacles to adversely affect the licensee's ability to complete a comprehensive examination of the lower head.

6. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

   The examination determined that there were no identified deficiencies requiring repair nor any evidence of degradation or leakage originating from the reactor lower head surface or instrument interface.

7. What, if any, impediments to effective examinations, for each of the applied non-destructive examination methods, were identified (e.g., insulation, instrumentation, nozzle distortion)?

   The licensee removed almost all side insulation panels to gain access to the lower head area for the direct visual examination.

8. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

   There was suspected white powder deposit on the lower weld of nozzle 48, which was examined by liquid penetrant examination and found to have no cracks. The very small amount of deposit was removed and chemically analyzed. The result showed no boron in the sample. The licensee also video taped each nozzle for baseline reference. There were no boric acid leaks from the surface of the lower head or the nozzle welds.

9. Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared (FTIR)), what constituents were looked for (e.g., boron, lithium, specific isotopes), and what were the licensee's criteria for determining any boric acid deposits were not from the RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?

   The licensee collected a very small amount of the suspected deposit and performed chemical analysis. No boric acid deposit content or boron was found in the sample collected. The deposit was suspected to be the wrapped tape and heated by the high temperature of the reactor coolant.

10. Is the licensee planning to do any cleaning of the head?

    No, there were not boron deposits identified to necessitate cleaning.

11. What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?

    The licensee performed chemical analysis for the collected sample which was suspected to be the boric acid deposit. The chemical analysis showed no boron in the sample. The sample was suspected to be the wrapped tape heated by the high temperature reactor coolant.

.3 <u>(Open) NRC TI 2515/153, "Reactor Containment Sump Blockage (NRC Bulletin 2003-01)" - Unit 1</u>

a. <u>Inspection Scope</u>

The inspectors performed a preliminary review of the licensee's activities in response to NRC Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors (PWRs)," in accordance with NRC TI 2515/153, "Reactor Containment Sump Blockage (NRC Bulletin 2003-01)," dated October 3, 2003, for North Anna Unit 1.

Procedure 1-PT-57.3, "Containment Recirculation Spray Sump Examination" was reviewed for the Unit 1 Spring 2003 Refueling Outage since it was performed after August 31, 2002, but prior to the issuance of TI 2515/153. Visual inspections and procedural reviews of the Unit 2 containment sumps, sump screens and flow paths were performed by the inspectors during the current refueling outage. The inspectors also reviewed the licensee's completed and proposed compensatory measures submitted in accordance with Bulletin 2003-01, Option 2, to verify they have been implemented or are planned and scheduled for implementation consistent with the licensee's response.

b. Findings

No findings of significance were identified for the preliminary review conducted. Pending Office of Nuclear Reactor Regulation review of the licensee's response letter, Serial Number 03-368, Revision 0, dated August 7, 2003, TI 2515/153 will remain open.

Specific inspection results for each question in the TI are discussed below.

a. For units that entered refueling outages (RFOs) after August 31, 2002, and subsequently returned to power: Was a containment walkdown to quantify potential debris sources conducted by the licensee during the RFO?

   Yes, North Anna Power Station Unit 1 containment sump was inspected on March 1, 2003, during the Spring RFO. The sump was again inspected during the current Fall refueling outage (U1 RFO-17) on September 15 and 17, 2004.

b. For units that are currently in a RFO: Is a containment walkdown to quantify potential debris sources being conducted during the current RFO?

   Yes, North Anna Power Station entered the current refueling outage on September 12, 2004, with a scheduled return to power on October 8, 2004. A containment walkdown was conducted by the licensee to quantify potential debris sources during the RFO on October 4, 2004.

c. For units that have not entered a RFO between September 1, 2002, and the present: Will a containment walkdown to quantify potential debris sources be conducted during the upcoming RFO?

   Not applicable since North Anna Unit 1 containment sump was inspected during the Spring 2003 RFO and during the Fall 2004 RFO. Unit 2 was inspected during the May 2004 RFO (U2 RFO-16).

d. Did the walkdowns conducted check for gaps in the sumps' screened flowpath and for major obstructions in containment upstream of the sumps?

   Yes, North Anna Power Station walkdowns conducted in March 2003 for Unit 1, and May 2004 for Unit 2 and again the current RFO for Unit 1, checked for gaps in the sumps' screened flowpath and for major obstructions in containment upstream of the sumps. The walkdowns were performed in accordance with the requirements of Procedures 1-PT-57.3, "Containment Recirculation Spray Sump Visual Examination," and 2-PT-57.3 for Unit 2. Issues with sump screen gaps, sump closeout inspection and containment building foreign material exclusion were captured in the licensee's corrective action program under Plant Issues (for Unit 1) –2003-1011, 1297; (for Unit 2) –2004-1542, 1682,1838 and 1890; and (for current Unit 1 RFO) –2004-3605, 3712 and 3744. Issues identified were corrected or evaluated as acceptable.

e. Are any advanced preparations being made at the present time to expedite the performance of sump-related modifications, in case it is found to be necessary after performing the sump evaluation?

North Anna Power Station sump evaluations and analysis have not yet been completed. In response to NRC Bulletin 2003-01, the licensee chose Option 2 and described interim compensatory measures that have been implemented or will be implemented. These efforts will attempt to reduce risk which may be associated with the potentially degraded or nonconforming ECCS and sump recirculation functions while complex evaluations to determine compliance proceed. No specific plant modifications were included in the set of interim compensatory actions to address potential recirculation performance issues.

The licensee was prepared to make sump screen related repairs or minor modifications based on the inspection results identified during the Unit 1 Spring 2003 and the current Fall RFO. Issues with vortex breaker grating corrosion and scaling issues on Unit 1 “A” recirculation spray pump screens were identified. One panel was replaced under work order 486942-01. Another panel will be replaced in the next RFO. Openings greater than 0.12 inches found during the walkdowns on Unit 2 during the Spring 2004 RFO were repaired.

No plans were developed by the licensee for major sump related modifications during the Unit 1 Spring 2003, current RFO, or in the May 2004 Unit 2 RFO. Depending on the results of the complex sump evaluations and anticipated further generic communications from the NRC and the industry, advanced preparations for modifications are anticipated for future refueling outages. The licensee is investigating plans to increase the sumps’ screen area and modify design to increase the available design margin.

The inspectors performed visual inspections of the containment sumps, sump screens and flow paths to the sumps during the current Unit 1 refueling outage and verified no major obstructions existed in the containment flowpath upstream of the sumps. The inspectors conducted a Mode 4 containment closeout inspection on October 4, 2004. Results of that inspection are to be documented in the Resident Integrated Inspection Report 05000338/2004006. During Mode 6 and defueled activities, the inspectors performed walkdowns of the sump screens after the licensee had completed their evaluation of the as-found condition. The inspectors identified additional openings that exceeded the licensee’s criteria that were overlooked by licensee engineering personnel during their review. Plant Issue –2004-3477 was initiated for the licensee to evaluate the additional screen openings.

The inspectors reviewed NRC Bulletin 2003-01, Option 2, interim compensatory measures implemented or planned. These actions appeared to be effectively implemented. The actions were reasonable with the intent to reduce the potential risk of emergency core cooling system and reactor building spray recirculation degradation. Additionally, the licensee compensatory actions included operator training on indications and potential recovery responses should sump clogging occur. The inspectors verified that licensee commitments to enhance the affected procedures and provide operator training were completed as scheduled.

.4 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)

a. Inspection Scope

The inspectors reviewed the licensee's response to NRC Bulletin 2004-01 and observed planned inspections listed in that response. The observations included witnessing of the visual examination of the steam space piping connections to the Unit 1 pressurizer, witnessing of the UT of the "A" safety valve piping connection to the pressurizer, and the review of the UT documentation for the remaining safety and relief valve piping connections to the pressurizer.

The inspectors verified that the visual inspections were conducted by personnel qualified to ASME Section XI, VT-2, who had undergone the licensee's BACC evaluator training. The UT examinations were conducted by an examiner qualified to ASME Section XI, Appendix VIII, Supplement 10, by the Dominion qualification program. Visual and UT inspections were conducted in accordance with licensee qualified procedures. The inspectors witnessed enough of the inspection activities to verify that the examinations were being conducted in accordance with the appropriate procedures.

The inspectors verified that the physical conditions of the pressurizer steam-space piping to vessel connections were clean and accessible for the prescribed inspections, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or viewing obstructions which could interfere with the identification of relevant indications.

The inspectors observed that:

- The visual inspections were by direct visual by the examination personnel.
- Examiners were able to adequately examine the pressurizer connections for 360E around the circumference of all the nozzles.
- Lighting and access were such that small boron deposits, as described in the Bulletin 2004-01, could have been identified and characterized.
- There were no material deficiencies (i.e., cracks, corrosion, etc.) identified that required repair.
- Other than the expected nozzle-to-safe-end geometry, there were no impediments to effective examinations, for visual or UT examinations.

There were no indications identified during the visual and UT examinations that would have required disposition and/or follow-on examinations.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting Summary

On August 18, 2004, the acting senior resident inspector presented interim inspection results to Mr. Jim Crossman and other members of his staff. On October 5, 2004, the resident inspectors presented the final inspection results to Mr. Jack Davis and other members of his staff who acknowledged the findings. Proprietary information was reviewed during the inspection; however, none is contained in this inspection report.

4OA7 Licensee-Identified Violations

The following findings of very low significance were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as Non-Cited Violations (NCV).

1. TS 3.6.9 requires two operable hydrogen recombiners. An inoperable recombiner must be restored to operable within 30 days or the affected unit must be in Mode 3 within 6 hours. Contrary to this, the licensee identified that the 2-HC-HC-1 hydrogen recombiner was inoperable for greater than the 30-day completion time due to two isolation valves that were mis-positioned. This was identified in the licensee's corrective action program as –2003-4019. This finding is of very low safety significance because the opposite train's hydrogen recombiner was available.

2. TS 5.4.1 states, in part, that written procedures shall be implemented to cover activities specified in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978. RG 1.33, Appendix A, Item 9a , requires that maintenance affecting the performance of safety-related equipment be properly performed in accordance with written procedures appropriate to the circumstances. Contrary to that on May 29, 2004, Unit 2 control room operators had to manually trip the reactor because the demand position indicator covers were not in their proper position following a previous adjustment by maintenance personnel. This was identified in the licensee's corrective action program as –2004-2127. This finding is of very low safety significance because the reactor was subcritical at the time of the event.

3. TS 3.6.2 requires that two containment air locks shall remain operable. In the event that one becomes inoperable, actions to verify within one hour the operable door is closed and lock the operable door closed within 24 hours must occur. Contrary to that, on June 6, 2004, the TS actions to verify, within one hour, the operable door is closed and lock the operable door closed within 24 hours were missed. This was identified in the licensee's corrective action program as –2004-2237. This finding is of very low safety significance because the redundant interior door remained operable, containment was operating under vacuum, and no leakage escaped to the atmosphere.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

K. Barnette, Supervisor, Site Industrial Safety/Fire Protection
J. Breeden, Supervisor, Radiological Protection
J. Crossman, Supervisor, Nuclear Engineering
J. Davis, Site Vice President
E. Dreyer, Supervisor Health Physics Technical Services
J. Eastwood, S/G ISI Coordinator
R. Evans, Manager, Radiological Protection
R. Foster, Supply Chain Manager
D. Jernigan, Director, Nuclear Operations & Maintenance
R. Jones, ISI Coordinator
P. Kemp, Manager, Nuclear Operations
T. Kendzia, Supervisor for the Component Performance
J. Kirkpatrick, Manager, Maintenance
L. Lane, Director, Nuclear Safety and Licensing
J. Leberstien, Licensing Technical Advisor
T. Maddy, Manager, Nuclear Protection Services
T. Mayer, NDE Coordinator, Areva
B. McBride, Supervisor, Emergency Preparedness
F. Mladen, Manager, Nuclear Site Services
B. Morrison, Assistant Engineering Manager
P. Naughton, SW System Engineer
J. Rayman, Emergency Planning Supervisor
W. Renz, Director, Nuclear Protection Services and Emergency Preparedness
H. Royal, Manager, Nuclear Training
M. Sartain, Manager, Nuclear Engineering
D. Smith, NDE Coordinator
B. Speckine, Supervisor Nuclear Fuel Handling
K. Taylor, NDE Engineer, Boric Acid Program Coordinator

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000338/2004005-01	NCV	Failure to Adequately Prevent the Improper Installation of Three Hydraulic Snubber Supports (Section 4OA2.2)

Closed

05000338, 339/2003005-00	LER	Inoperable Hydrogen Recombiner Due to Inadequate Work Practices (Section 4OA3.2)

05000339/2004002-00	LER	Manual Reactor Trip Due to Control Bank "D" Group Step Counter Inoperable (Section 4OA3.3)
05000339/2004003-00	LER	Inoperable Containment Personnel Lock Resulting in issued Surveillance (Section 4OA3.4)
05000339/2004004-00	LER	Reactor Trip Due to Incorrect Cell Switch Contact Configuration on Bypass Reactor Trip Breaker (Section 4OA3.5)
2515/152, Rev. 1 (Unit 1)	TI	Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02) (Section 4OA5.2)

Discussed

2515/153 (Unit 1)	TI	Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

Section 1R04: Equipment Alignment

Drawings

- 1175-FM-079A, Component Cooling Water System, sheet 2
- 12050-FM-079A, Component Cooling Water System, sheet 1
- 1175-FM-096A, Safety Injection, sheets 1 and 2

Section 1R08: Inservice Inspection Activities

Documents

- NDE-UT-808, Ultrasonic Examination of Dissimilar Metal Piping Welds, Rev. 0, April 27, 2004
- NDE-UT-803, Single or Two Side Access Ultrasonic Examination of Austenitic Piping Welds, Rev. 2, April 22, 2004
- –2204-2728, Root Cause Evaluation, Through-wall Leak in Low Head SI Weld, Unit 1
- DNAP-1004, Boric Acid Corrosion Control (BACC) Program, Rev. 2
- NASES-6.23, Boric Acid Corrosion Control (BACC) Program, Rev. 1
- VPAP-0820, S/G Program, Rev. 0
- NAP-SGPMS-001, North Anna Site Specific Eddy Current Analysis Guidelines, Rev. 7
- 1274768A, Secondary Side Visual Inspection and Loose Parts Retrieval Procedure for Heat Exchangers, Rev. 2
- 0-MCM-1801-01, Welding Safety-Related and Seismic-Related Equipment, Rev. 15 P-1

- Boric Acid Corrosion Control - System Health Report 2004-2
- Repair/Replacement Plan Number 2004-103
- Work Order 00515656, Replace 12" Piping
- NIS-2A Repair/Replacement Certification Record

Section 1R13: Maintenance Risk Assessment and Emergent Work Control

Documents

- 2-OP-8.3, “Boron Concentration Control”
- Technical Specification Change Request N-025A, “TS 3.5.2 - ECCS Operating, Unit 1 Only”

Section 1R15: Operability Evaluations

Procedures

- 2-GOP-8.3.3, “Placing the Blender in the Manual Make-up Mode of Operation”
- 2-TOP-8.3.3, “Performing Dilution While the Blender is in the Manual Mode”
- VPAP-1408, “System Operability”

Plant Issues

- –1998-1692
- –1998-2001
- –1998-0676
- –1998-1683
- –2004-2243
- –2004-2263

Section 1R19: Post Maintenance Testing

Documents

- 2-OP-7.4, “Recirc of RWST Using QS Pumps”
- OTO PAR 1-PT-213.8A,”Valve Inservice Inspection Train”A” of Safety Injection”
- 1-PT-14.5, “Venting ECCS Lines”
- 1-PT-63.1A, “Quench Spray System “A” Subsystem”

Sections 1EP2 - 1EP5: Reactor Safety - Emergency Preparedness

Plans and Procedures

- North Anna Power Station Emergency Plan, Revision 28
- North Anna Power Station Emergency Plan, Revision 29
- 1-PT-172.3, “Early Warning System Polling Function Test”
- Whelan WSL-846, Whelan Status Logger Installation Manual

Plant Issues

- N-2003-3245-E1, Discrepancies in DEP PI data identified after final data submittal, 08/26/2003
- N-2004-0084-E1, Adverse trend in DEP PI statistics, 01/08/2004

Section 4OA5: Other Activities

Documents

- Engineering Periodic Test Procedure 1-PT-48.4, Revision 1, Bare Metal Inspection of Vessel BMI Nozzles
- VPAP-1103, "ASME Section XI Visual Examination Program (VT-1,2,3 & General)
- North Anna Unit 1 VT-2 Visual Examination Report for Bottom Mounted Incore Penetration on Lower Reactor Vessel Head dated September 13, 2004
- Liquid Penetrant Report PTRNO: 8588 for Reactor Vessel Bottom Head Penetration 48 on the Lower weld of the Nozzle
- VT-2 Level II Examiner and Liquid Penetrant Examination Level II Examiner Qualification and Certification Records
- Nondestructive Examination Procedure NDE-PT-101, Revision 10, Liquid Penetrant Examination
- Evaluation and Chemical Analysis Report for the Suspected Boric Acid Deposit on Nozzle 48

LIST OF ACRONYMS

ASME	-	American Society of Mechanical Engineers
B&PV	-	Boiler and Pressure Vessel
BACC	-	Boric Acid Corrosion Control
CFR	-	Code of Federal Regulations
EAL	-	Emergency Action Level
ECCS	-	Emergency Core Cooling System
ECT	-	Eddy Current Test
EDG	-	Emergency Diesel Generator
EHC	-	Electro-Hydraulic Control
ERO	-	Emergency Response Organization
ISFSI	-	Independent Spent Fuel Storage Installation
ISI	-	Inservice Inspection
LER	-	Licensee Event Report
NCV	-	Non-Cited Violation
NDE	-	Nondestructive Examination
NEI	-	Nuclear Energy Institute
NRC	-	Nuclear Regulatory Commission
PI	-	Performance Indicator
PMT	-	Post-Maintenance Test

PT	-	Liquid Penetrant Examination
PWR	-	Pressurized Water Reactor
RCS	-	Reactor Coolant System
Rev.	-	Revision
RFO	-	Refueling Outage
RG	-	Regulatory Guide
RPV	-	Reactor Pressure Vessel
SDP	-	Significance Determination Process
SG	-	Steam Generator
TI	-	Temporary Instruction
TS	-	Technical Specification
UFSAR	-	Updated Final Safety Analysis Report
UT	-	Ultrasonic Examination
VPAP	-	Virginia Power Administrative Procedure
VT	-	Visual Examination
WO	-	Work Order