UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

October 29, 2010

Mr. David A. Heacock
President and Chief Nuclear Officer
Virginia Electric and Power Company
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060

SUBJECT: NORTH ANNA POWER STATION – NRC INTEGRATED INSPECTION REPORT 05000338/2010004, 05000339/2010004 AND 07200056/2010001

Dear Mr. Heacock:

On September 30, 2010, the U. S. 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 October 23, 2010, with Mr. Larry Lane and other members of your staff.

The inspection examined activities conducted under your licenses as they related 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 apparent violation and one finding both of which have potentially greater than very low safety significance (Green). This report also documents two NRC-identified and three self-revealing findings of very low safety significance. Three of these findings were determined to be violations of NRC requirements. However, because these findings are of very low safety significance and were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) consistent with the NRC Enforcement Policy. If you wish to contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the North Anna Power Station.

Additionally, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, 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, its 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 the 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/

Gerald J. McCoy, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket Nos.: 50-338, 50-339, 72-056
License Nos.: NPF-4, NPF-7

Enclosure: Inspection Report 05000338/2010004, 05000339/2010004, and 7200056/2010001
w/ Attachment: Supplemental Information

cc w/ encl. (See page 3)

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Letter to David A. Heacock from Gerald J. McCoy dated October 29, 2010

SUBJECT: NORTH ANNA POWER STATION – NRC INTEGRATED INSPECTION REPORT 05000338/2010004, 05000339/2010004 AND 07200056/2010001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-338, 50-339, 72-056
License Nos:	NPF-4, NPF-7
Report No:	05000338/2010004, 05000339/2010004, 07200056/2010004
Licensee:	Virginia Electric and Power Company (VEPCO)
Facility:	North Anna Power Station, Units 1 & 2 and the North Anna Independent Spent Fuel Storage Installation
Location:	1022 Haley Drive Mineral, Virginia 23117
Dates:	July 1, 2010 through September 30, 2010
Inspectors:	J. Reece, Senior Resident Inspector R. Clagg, Resident Inspector J. Dodson, Senior Project Engineer, Sections 1R05 and 1R19 P. Fillion, Senior Reactor Inspector, Section 4OA3.3 M. Coursey, Reactor Inspector, Section 1R08 and 4OA5.5
Approved by:	Gerald J. McCoy, Chief Reactor Projects Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000338/2010004, 05000339/2010004, 07200056/2010001; 07/01/2010 – 09/30/2010; North Anna Power Station, Units 1 and 2, and North Anna Independent Spent Fuel Storage Installation: Plant Modifications; Identification and Resolution of Problems; Event Followup; and Other Activities.

The report covered a 3 month period of inspection by resident inspectors and reactor inspectors from the region. Seven findings were identified, three of which were determined to be non-cited violations (NCVs). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross-cutting aspect was determined using IMC 0310, "Components Within the Cross Cutting Areas." 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 4, dated December 2006.

NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A non-cited violation of Technical Specifications 5.4.1a was identified by the inspectors for the failure to adequately implement procedural requirements which resulted in operation of the 'A' reactor coolant system (RCS) pump (RCP) beyond the motor high bearing temperature limit of 195 degF for approximately 10 minutes. The licensee entered this problem into their corrective action program as corrective action 170278 associated with condition report 382725.

  The inspectors determined that the failure to implement an alarm response procedure to trip the 'A' RCP in a timely manner was a performance deficiency (PD). The PD was more than minor, because it could be reasonably viewed as a precursor to a significant event due to RCP motor operation in an unknown condition of bearing performance in which the melting of Babbitt material can lead to excessive shaft vibrations and consequent adverse impact on RCP seal performance leading to a seal loss of coolant accident. Significance determination process (SDP) phase 1 screening determined the finding to be a primary system loss of coolant accident initiator contributor as RCP operation without motor bearing cooling could lead to motor bearing failure, RCP vibration and potential vibration induced RCP seal damage. The finding was determined to fit under the Initiating Events cornerstone in that assuming worst case degradation the potential seal leakage could exceed the technical specification limit for RCS leakage and required phase 2 analysis. Since the North Anna SDP pre-solved worksheet did not specifically address loss of cooling to the RCP motor bearings, a phase 3 analysis was performed by a regional SRA using the NRC's North Anna SPAR model. The sequence was a reactor trip transient caused by a lightning strike in the switchyard, loss of the 1H emergency bus, RCP motor bearing damage due to loss of bearing cooling, failure to trip the RCP, RCP seal failure, failure of high pressure injection, successful depressurization and failure of low pressure injection leading to core damage. A diagnosis and action human error probability for RCP trip was developed for the event conditions. The risk of the event was mitigated by the availability of seal cooling, seal injection and the time and cues available to the operator to trip the RCP prior to vibration induced seal failure. The phase 3 risk evaluation determined that the risk increase of the finding was <1E-6 for core damage frequency and <1E-7 for Large Early Release Frequency, a finding of very low risk significance (Green). This finding involved the cross-cutting area of human performance, the component of decision making and the aspect of decision communications, H.1(c), because a reactor operator failed to communicate the loss of component cooling to the RCP motors to the senior reactor operator which led to the failure to trip the ‘A’ RCP on exceeding the motor bearing high temperature limit. (Section 4OA5.3)

- Green. A self-revealing finding was identified for the failure to establish an adequate set point for a balance-of-plant 4160 V bus undervoltage protection relay. The inadequate set point caused a reactor trip upon automatic start of a steam generator feedwater pump. The event was reported to the NRC in Licensee Event Report (LER) 0500339/2010-002-00. Corrective action has been taken to reduce the probability of recurrence of the problem. The licensee has placed this issue in their corrective action program as Root Cause Evaluation (RCE) 001012.

  The fact that the motor starting voltage dip of the twin 4500 horsepower motor feedwater pump was below the set point of the bus undervoltage protection relays was a performance deficiency. The typical industry standard practice for bus undervoltage is that the set point be below the motor starting voltage dip to preclude spurious actuation of the undervoltage relays for expected voltage transients such as motor stating. This industry standard practice is documented in Institute of Electrical and Electronics Engineers Standard 666-1991, “IEEE Design Guide for Electric Power Service Systems for Generating Stations.” Table 7.2, “Motor Protection Devices,” states that the suggested setting for undervoltage relay is that it be set to override voltage drop due to motor starting. The potential for spurious tripping of the undervoltage relays has nuclear safety ramifications, in that it can contribute to a reactor trip, as it did on May 28, 2010. The performance deficiency is more than minor because it was associated with the attribute of design control and adversely affected the objective of the initiating event cornerstone. The inappropriate undervoltage relay set point contributed to a reactor trip which is an event that upset plant stability and challenged critical safety functions. The finding was evaluated for significance using Inspection Manual Chapter 0609, Appendix E. The finding was determined to be very low safety significance, Green, because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation functions will not be available. The cause of the finding was evaluated in the licensee’s corrective action program as RCE001012. According to the LER and RCE001012, the cause of the finding was determined to be lack of a design basis for the undervoltage protection relay. Since the set point was established well outside the two-year window of current performance and there was no prior event that provided an opportunity to identify this problem, this issue did not represent current licensee performance. Therefore, no associated cross-cutting aspect was identified. (Section 4OA3.3)

- Green. A self-revealing finding was identified for the licensee’s failure to conduct an adequate review of calculations for the operation of the Unit 2 main generator automatic voltage regulator (AVR), as required by licensee procedure CM-AA-CLC-301, “Engineering Calculations”, Rev. 3, which resulted in the actuation of a main generator protective lockout relay and subsequent main turbine/reactor trip. The licensee entered this problem into their corrective action program as condition report 378800.

The inspectors determined that the failure to conduct an adequate owner's review of calculation EE-0826, as required by licensee procedure CM-AA-CLC-301, "Engineering Calculations", Rev. 3, was a performance deficiency (PD). The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to example 4.b in that the procedural error resulted in a reactor trip or other transient. In addition, the inspectors determined that it adversely impacted the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations, specifically the attribute of Design Control in that the AVR design change was not properly controlled and Human Performance in that licensee personnel conducting the owner's review failed to follow the requirements of CM-AA-CLC-301 and conduct an owner's review of calculation EE-0826. The inspectors reviewed IMC 0609 Attachment 4 and determined that the finding was of very low safety significance, or Green, because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The cause of this finding involved the cross-cutting area of human performance, the component of decision making, and the aspect of conservative assumptions and safe actions, H.1(b), because the licensee failed to use conservative assumptions and demonstrate that the proposed action was safe in making the decision that the incorrect inputs for the five-point curve would not be used by the MEL tuning software. (Section 4OA3.1.1)

- TBD. A self-revealing finding was identified for the failure to maintain a preventative maintenance (PM) procedure for circuit breakers current with industry information and operating experience (OE), as required by procedure, DNAP-2001, "Equipment Reliability Process," Revision 0. The licensee entered this problem into their corrective action program as condition report 331819.

  The inspectors determined that the failure to maintain PM procedures for circuit breakers current with industry information and OE was a performance deficiency (PD). This PD had a credible impact on safety due to an original equipment main contactor which was in service for approximately 35 years, and subsequently experienced a coil failure with a consequent fire. The PD was more than minor because it could be reasonably viewed as a precursor to a significant event based on fire development leading to the loss of other safety-related equipment. In accordance with NRC Inspection Manual Chapter 0609, "Significance Determination Process," the inspectors performed a Phase 1 analysis and determined the finding required a Phase 3 analysis by a regional senior reactor analyst. The significance of this finding is to-be-determined (TDB) pending completion of a phase 3 evaluation. This finding involved the cross-cutting area of corrective action, the component of the OE, and the aspect of implementation and institutionalization of OE through changes to station processes and procedures, P.2(B), because the licensee failed to incorporate existing industry OE to ensure procedural guidance was adequate for testing of the main contactor. (Section 4OA5.4)

Cornerstone: Mitigating Systems

- Green. A non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors for the failure to ensure that design control measures for a field change performed on the Unit 1, '1J' emergency diesel generator (EDG) starting air receivers were commensurate with those of the original design. The field change consisted of a procedurally controlled temporary modification (TM) that installed a non-safety related hose between the safety related EDG starting air receivers. The licensee entered this problem into their corrective action program as condition report 389521.

  The inspectors determined that the failure to adhere to the requirements of Criterion III for a field change involving a procedurally controlled TM was a performance deficiency (PD). This PD had a credible impact on safety due to the implementation of a TM which introduced a common mode failure mechanism for both EDG starting air receivers which would render the respective EDG unavailable and inoperable. The PD was more than minor, because it impacted the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences and the related attribute of design controls due to the removal of independence between the EDG starting air receivers and consequent impact on the redundancy of the EDGs. In accordance with NRC Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," the inspectors performed a Phase 1 analysis and determined that the finding was of very low significance (Green) because the design deficiency did not result in the loss of functionality. The finding had no cross-cutting aspects because it is not indicative of current licensee performance. (Section 1R18.1)

- Green. A self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified for the failure to correctly translate the design basis of the Unit 2 turbine driven auxiliary feedwater pump (TDAFWP) lube oil subsystem vent into specifications or drawings. The licensee entered this problem into their corrective action program as condition report 378798.

  The inspectors determined that the licensee's failure to correctly translate the Unit 2 TDAFWP lube oil subsystem vent into specifications or drawings as required by Criterion III was a performance deficiency (PD). The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to examples 3b and 3k in that the failure to correctly translate the design into drawings adversely impacted the operation of the system and resulted in reasonable doubt about the operability of the system. The inspectors reviewed IMC 0609 Attachment 4 and determined that the finding was of very low safety significance, or Green, because the finding was a design or qualification deficiency confirmed not to result in loss of operability or functionality. The cause of this finding did not involve a cross-cutting aspect because it is not indicative of current licensee performance. (Section 4OA3.1.2)

Cornerstone: Barrier Integrity

- TBD. An apparent violation (AV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified by the inspectors for two examples of the failure to promptly identify and correct a condition adverse to quality present in the actuator diaphragms of 1-CH-HCV-1200C, letdown orifice isolation, and 1-RC-PCV-1456, reactor coolant system (RCS) pressurizer power operated relief valve (PORV). The licensee entered these problems into their corrective action program as condition reports 355000 and 387916.

  The inspectors determined that the failure to promptly correct conditions adverse to quality for 1-CH-HCV-1200C and 1-RC-PCV-1456 was a performance deficiency (PD). The NRC Enforcement Manual allows for the grouping of multiple examples of the same violation during an inspection period and the assignment of an issue to that example which is most significant. The inspectors determined that the second example, involving 1-RC-PCV-1456, was the more significant issue. The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to examples 4d and 4f in that the failure to correct a condition adverse to quality led to the inoperability of the component. The inspectors also reviewed IMC 0612, Appendix B and determined the finding was also more than minor because it affected the Barrier Integrity cornerstone objective of providing reasonable assurance that physical design barriers (e.g. RCS) protect the public from radionuclide releases caused by accidents or events. Specifically, the pressurizer PORVs provide protection to the RCS by preventing brittle fracture at low temperature conditions and protect RCS integrity at high temperature conditions. The inspectors reviewed IMC 0609, Attachment 4 and determined that since the finding involved a degradation of the Barriers Cornerstone, specifically the RCS barrier, a phase 3 analysis was required. The significance of this finding is to be determined pending completion of the phase 3 evaluation. The cause of this finding involved the cross-cutting area of problem identification and resolution, the component of corrective action program, and the aspect of implementation of corrective action, P.1(d), because the licensee failed to correct the safety issue that existed with 1-RC-PCV-1456 in a timely manner, commensurate with its safety significance and complexity. (Section 4OA2.2)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at full Rated Thermal Power (RTP) and operated at full power until July 14, 2010, when the unit experienced a forced outage to repair an un-isolable leak on the ‘C’ steam generator sample line. The unit returned to at or near full RTP on July 19, 2010 and continued until September 12, 2010, when a planned refueling outage began.

Unit 2 began the period at full RTP and operated at full power until September 29, 2010, when the unit entered a forced shutdown and outage.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted two equipment alignment partial walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out of service. The inspectors reviewed the functional systems descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system.

- Unit 2 ‘B’ Motor Driven Auxiliary Feedwater (MDAFW) pump and Turbine Driven AFW (TDAFW) pump during scheduled maintenance on the ‘A’ MDAFW pump
- 1-PT-12.1B, “Boration Flow Path Verification – Shutdown,” Revision 5, for verification of boration flows paths during Unit 1 refueling outage

b. Findings

No findings were identified

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of the four areas listed below that are important to reactor safety to verify the licensee’s implementation of fire protection requirements as described in fleet procedures CM-AA-FPA-100, Revision 1, “Fire Protection/Appendix R (Fire Safe Shutdown) Program,” CM-AA-FPA-101, “Control of Combustible and Flammable Materials,” Revision 2, and CM-AA-FPA-102, “Fire Protection and Fire Safe

Shutdown Review and Preparation Process and Design Change Process," Revision 0. The inspectors evaluated, as appropriate, conditions related to: (1) licensee control of transient combustibles and ignition sources; (2) the material condition, operational status, and operational lineup of fire protection systems, equipment, and features; and (3) the fire barriers used to prevent fire damage or fire propagation.

- Emergency Switchgear Room Unit 1 (fire zone 6-1a / ESR-1)
- Emergency Switchgear Room Unit 2 (fire zone 6-2a / ESR-2)
- Emergency Diesel Generator 1H Unit 1 (fire zone 9A-1a / EDG-1H) and Emergency Diesel Generator 2H Unit 2 (fire zone 9A-2a / EDG-2H)
- Emergency Diesel Generator 1J Unit 1 (fire zone 9B-1a / EDG-1J) and Emergency Diesel Generator 2J Unit 2 (fire zone 9B-2a / EDG-2J)

b. Findings

No findings were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors selected the risk significant Unit 1 and Unit 2 Main Control Room/Emergency Switchgear Room Heating and Ventilation Chillers and reviewed inspection records, test results, maintenance work orders, and other documentation to ensure that deficiencies which could mask or degrade performance were identified and corrected. The test procedures and records were also reviewed to verify that they were consistent with Generic Letter 89-13 licensee commitments, and Electric Power Research Institute (EPRI) Heat Exchanger Performance Monitoring Guidelines. In addition, the inspectors reviewed inspection documentation of the related service water piping to assess general material condition and to identify any degraded conditions. Documents reviewed included Virginia Power Administrative Procedure (VPAP) -0811, "Service Water Inspection and Maintenance Program," Revision 6, and Procedure ER-AA-HTX-1003, "Heat Exchanger Monitoring and Assessment," Revision 5

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08P)

From September 20, 2010 to September 24, 2010, the inspectors conducted a review of the implementation of the licensee's Inservice Inspection (ISI) Program for monitoring degradation of the reactor coolant system, steam generator tubes, emergency feedwater systems, risk-significant piping and components and containment systems.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, 1R08.4 and 1R08.5 below constituted one inservice inspection sample as defined in Inspection Procedure 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors observed the following non-destructive examinations (NDEs) mandated by the American Society of Mechanical Engineers Code Section XI to evaluate compliance with the ASME Code Section XI and Section V requirements and, if any indications and defects were detected, to evaluate if they were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement.

- UT of Elbow to Nozzle for “C” Steam Generator feedwater inlet
- PT of RHR Elbow to Nozzle at 11715-WMKS-0113A-1/14-RH-2/71H

During the non-destructive surface and volumetric examinations performed since the previous refuelling outage, the licensee did not identify any recordable indications that were analytically evaluated for continued service. Therefore, no NRC review was completed for this inspection procedure attribute.

The inspectors reviewed the following pressure boundary welds completed for risk-significant systems during the last Unit 1 refueling outage to evaluate if the licensee applied the preservice non-destructive examinations and acceptance criteria required by the construction Code and the ASME Code Section XI. In addition, the inspectors reviewed the welding procedure specification and supporting weld procedure qualification records to evaluate if the weld procedure(s) were qualified in accordance with the requirements of the Construction Code and ASME Code Section IX.

- 01-RC-105-VALVE, C Loop Main Connection to Prim Vent Pot Isol Valve

The inspectors reviewed the results of the visual examination (VE) for the bottom-mounted instrument penetrations to ensure examinations were being performed in accordance with the requirements of ASME Code Case N-722-1 and 10 CFR 50.55a(g)(6)(ii)(E).

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities

a. Inspection Scope

For the Unit 1 vessel upper head, no examination was required pursuant to 10 CFR 50.55a(g)(6)(ii)(D) for the current refueling outage. The inspectors also verified the basis for the licensee switching from the calculation of Effective Degradation Years (EDY) to the use of ASME Code Case 729.1 which North Anna committed to formally as of January 1, 2009.

b. Findings

No findings were identified.

.3 Boric Acid Corrosion Control (BACC)

a. Inspection Scope

The inspectors performed an independent walkdown of portions of borated systems which recently received a licensee boric acid walkdown and evaluated if the licensee's BACC visual examinations emphasized locations where boric acid leaks could cause degradation of safety-significant components.

The inspectors reviewed the following licensee evaluations of reactor coolant system components with boric acid deposits to evaluate if degraded components were documented in the corrective action system. The inspectors also evaluated the corrective actions for any degraded reactor coolant system components against ASME Code Section XI and other licensee committed documents:

- 1-BR-P-7B, 7B Gas Stripper Circulation Pump dated 8/10/2010
- 1-FC-E-1A, Fuel Pit Cooler dated 9/9/2010
- 1-SI-P-1B, B LHSI Pump dated 5/13/2010
- 1-RP-P-1A/A Refueling Purification Pump dated 08/09/2010

The inspectors reviewed the following corrective actions related to evidence of boric acid leakage to evaluate if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- CR394271 1-PT-46.21 leaks identified during boric acid walkdown

b. Findings

No findings were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI/SG related problems entered into the licensee's corrective action program and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying ISI/SG related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and

- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

The inspectors observed an operator requalification simulator scenario which involved a steam generator tube rupture and subsequent cooldown using the backfill method. 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 instructor and reviewed with the operators.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

For the two equipment issues listed below and involving maintenance rule evaluations (MRE), the inspectors evaluated the effectiveness of the respective licensee's 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 licensee staff. The inspectors compared the licensee's actions with the requirements of the Maintenance Rule (10 CFR 50.65), and licensee procedure ER-AA-MRL-10, "Maintenance Rule Program," Revision 4.

- MRE010215, Confirmed single fuel rod failure, fuel placed in (a)(1) status
- MRE012307, 2-BY-C-2, 125VDC Bus 2-I battery charger declared inoperable

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors evaluated, as appropriate, the five activities listed below for the following: (1) effectiveness of the risk assessments performed before maintenance activities were conducted; (2) management of risk; (3) upon identification of an unforeseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) maintenance risk assessments and emergent work problems were adequately identified and resolved. The inspectors verified that the licensee was in compliance with the requirements of 10 CFR 50.65 (a)(4) and the data output from the licensee's safety monitor associated with the risk profile of Units 1 and 2.

- Emergent work on vital battery charger 2-BY-C-2 due to heat damage associated with an alarm circuit board
- Emergent work on Technical Support Center uninterruptible power supply causing inoperability of AMSAC
- Emergent work associated with Unit 2 pressurizer pressure master controller 2-ICP-RC-P-2444
- Emergent work for failure of Unit 2 'A' SG steam flow channel 3 due to a card failure
- Emergent work for failure of Unit 2 'A' SG low-low level channel 1 due to a comparator card failure

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed seven operability evaluations, listed below, affecting risk-significant mitigating systems, to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered as compensating measures; (4) whether the compensatory measures, if involved, were in place, would work as intended, and were appropriately controlled; and (5) where continued operability was considered unjustified, the impact on TS Limiting Conditions for Operation and the risk significance in accordance with the Significant Determination Process (SDP). The inspectors' review included a verification that determinations of operability were made as specified by Procedure OP-AA-102, "Operability Determination," Revision 6.

- CR388574, "Weak link calc shows yoke of main FW isolation valves not seismically qualified"
- Operability Determination (OD) 000378, "Provide OD documentation of 1-RS-MOV-156A operability with weak yoke problem"
- CR391850, "Service water leak reported on SW channel addition piping"

- OD000382, “Develop an operability determination associated with support
- FPH-PHLD-1-23 for service water piping supplying Unit 2 control room chillers”
- OD000383, “Provide an operability determination for leakage associated with
- 2-BD-TV-200B”
- OD000380, “Perform operability determination of 2-BD-TV-200D with the present plug leakage”
- Engineering Transmittal, ET-N-10-0051, “Evaluation of 2-FW-P-2 Lube Oil Reservoir Over Pressurization”

b. Findings

The enforcement aspects related to ET-N-10-0051 are discussed in Section 4OA3.1.2.

1R18 Plant Modifications

.1 Temporary Modifications

a. Inspection Scope

The inspectors reviewed Procedure 1-OP-6.7, “Diesel Air System,” Revision 12, a procedurally controlled temporary modification (TM) affecting EDG air start subsystems, to verify that the TM did not affect the systems’ operability or availability as described by the TS and UFSAR. In addition, the inspectors verified that the temporary modification was in accordance with VPAP-1403, “Temporary Modifications,” Revision 13, and the related work package, that adequate controls were in place, procedures and drawings were updated, and post-installation tests verified the operability of the affected systems.

b. Findings

Introduction: The inspectors identified a Green, non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion III, “Design Control,” for the failure to ensure that design control measures for a field change performed on the Unit 1, ‘1J’ emergency diesel generator (EDG) starting air receivers were commensurate with those of the original design. The field change consisted of a procedurally controlled TM that installed a non-safety related hose between the safety related EDG starting air receivers.

Description: On July 27, 2010, during the normal control room log review, the inspectors identified that the licensee had installed a hose between the Unit 1 ‘1J’ EDG starting air receivers. During a subsequent review of the related operations procedure, 1-OP-6.7, “Diesel Air System,” Revision 12, step 5.3, “Pressurizing One Emergency Diesel Gen Starting Air Receiver From the Other,” the inspectors determined that the non-safety related hose assembly was installed via a procedurally controlled TM. The inspectors’ review of 1-OP-6.7 determined that the TM was not required during every maintenance activity involving work on a starting air compressor, was not specifically required to perform any maintenance activity, and was only implemented at the discretion of the operators. The inspectors also noted that 1-OP-6.7 did not require continuous operator presence when the two starting air receivers were cross connected. Additionally, the inspectors performed a review of the related design basis documentation to determine the EDG starting air subsystem design attributes.

The USFAR Section 9.5.6, “Diesel-Generator Starting Air System,” Revision 45, states in part that the EDG is provided with two independent air-starting systems, either of which is capable of starting the engine without outside power. Each engine-starting system includes a non-safety related electric-motor- or diesel-engine-driven air compressor, after cooler, and air-drying equipment, and a safety related air storage tank or receiver. Additionally, TS Bases, B 3.8.3, “Diesel Fuel Oil and Starting Air,” Background Section, Revision 31, states in part that each EDG has an air start system that contains two separate and independent subsystems and that only one air start receiver is required for the EDG to be considered operable.

The inspectors concluded that the connection of a non-safety related hose assembly between the two safety related air receivers presented a common mode failure mechanism that would allow the depressurization of both air receivers due to hose failure. Consequently, the TM would remove the independence aspect described in the UFSAR and TS Bases and introduce a reduction in the inherent redundancy of the two train EDG design for defense in depth. The inspectors also concluded that the use of a non-safety related hose assembly connected to safety related components constituted a field change for which the design control measures were not commensurate with those of the original design as required by 10 CFR 50, Appendix B, Criterion III.

Analysis: The inspectors identified a performance deficiency (PD) for the failure to adhere to the requirements of Criterion III for a field change involving a procedurally controlled TM that failed to follow the design control measures for the respective safety related starting air receivers. This PD had a credible impact on safety due to the implementation of a TM which introduced a common mode failure mechanism for both EDG starting air receivers which would render the respective EDG unavailable and inoperable. The PD was more than minor, because it impacted the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences and the related attribute of design controls due to the removal of independence between the EDG starting air receivers and consequent impact on the redundancy of the EDGs. In accordance with NRC Inspection Manual Chapter (IMC) 0609, “Significance Determination Process,” the inspectors performed a Phase 1 analysis and determined that the finding was of very low significance (Green) because the design deficiency did not result in the loss of functionality. The finding had no cross-cutting aspects due to its legacy nature.

Enforcement: 10 CFR 50, Appendix B, Criterion III, “Design Control,” requires in part that design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design. Contrary to this, on July 27, 2010, the licensee failed to ensure that design control measures for a field change, which involved a procedurally controlled TM installed on the ‘1J’ EDG starting air receivers, were commensurate with those of the original design. Consequently, implementation of the TM introduced a common mode failure mechanism for both EDG starting air receivers which would render the respective EDG unavailable and inoperable. Because this finding is of very low safety significance and because it was entered in the licensee's corrective program as CR 389521, this violation is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000338/2010004-01, Inadequate Procedurally Controlled Temporary Modification for the Emergency Diesel Generator Starting Air System.

.2 Permanent Modifications

a. Inspection Scope

The inspectors reviewed the completed permanent plant modification listed below. The inspectors conducted a walk down of the installations, discussed the desired improvements with system engineers, and reviewed the 10 CFR 50.59 Safety Review/Regulatory Screenings, technical drawings, test plans and the modification packages to assess the TS implications.

- Design Change Package NA-10-004, "Installation of a Lag Time Constant in Delta T and T Average protection/North Anna/Units 1 and 2"

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed five post maintenance test procedures and/or test activities for selected risk-significant mitigating systems listed below, to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform in accordance with VPAP-2003, "Post Maintenance Testing Program," Revision 13. Documents reviewed are listed in the Attachment.

- WO 59101703832, Perform 5 year PM on Unit 2 'A' MDAFW pump and motor
- WO 59101674978, Replace Air Regulatory on 1-FW-HCV-100A
- WO 59079887501, Replace C-1 Capacitor Bank in 2-BY-C-04
- WO 59102155594, Replace low voltage alarm card and relay in 2-I battery charger
- WO 59101877786, Repair carbon gland housing leak outboard end of turbine for 2-FW-P-2 vertical plug

b. Findings

The enforcement aspects associated with WO 59101877786 are discussed in Section 4OA3.1.2.

1R20 Refueling and Other Outage Activities

.1 Unit 1 Refueling Outage

a. Inspection Scope

The inspectors reviewed the Outage Safety Review (OSR) and contingency plans for the Unit 1 refueling outage, which began September 12, 2010, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. The inspectors used Inspection Procedure 71111.20, "Refueling and Outage Activities," to observe portions of the shutdown, cooldown, refueling, and maintenance activities to verify that the licensee maintained defense-in-depth commensurate with the outage risk plan and applicable TS and monitor the licensee's fatigue management in accordance with 10 CFR 26. The inspectors monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including daily outage reports, to evaluate maintenance of defense-in-depth commensurate with the OSR for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing.
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and an accounting for instrument error.
- Controls over the status and configuration of electrical systems to ensure that TS and outage safety plan requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal.
- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.
- Refueling activities, including fuel handling and sipping to detect fuel assembly.
- Licensee identification and resolution of problems related to refueling outage activities.

b. Findings

No findings were identified.

.2 Unit 2 Forced Outage

a. Inspection Scope

The inspectors reviewed the Outage Safety Review (OSR) and contingency plans for a Unit 2 forced outage, which began September 29, 2010, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. The cause of the forced outage is under review by a NRC Special Inspection Team who will document the results of the inspection in NRC Inspection Report 05000338/2010006, 05000339/2010006.

The inspectors used Inspection Procedure 71111.20, “Refueling and Outage Activities,” to observe portions of the shutdown, cooldown, refueling, and maintenance activities to verify that the licensee maintained defense-in-depth commensurate with the outage risk plan and applicable TS and monitor the licensee’s fatigue management in accordance with 10 CFR 26. The inspectors monitored licensee controls over the outage activities listed below.

- Licensee configuration management, including daily outage reports, to evaluate maintenance of defense-in-depth commensurate with the OSR for key safety functions and compliance with the applicable TS when taking equipment out of service.
- Controls over the status and configuration of electrical systems to ensure that TS and outage safety plan requirements were met, and controls over switchyard activities.
- Monitoring of decay heat removal.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Controls over activities that could affect reactivity.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

For the five surveillance tests listed below, the inspectors examined the test procedures, witnessed testing, or 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 TS were met. The inspectors also determined whether the testing effectively demonstrated that the systems or components were operationally ready and capable of performing their intended safety functions.

In-Service Test:

- 1-PT-71.3Q, "1-FW-P-3B, B Motor-Driven AFW Pump and Valve Test," Revision 46
- 2-PT-57.1B, "Emergency Core Cooling Subsystem Low Head Safety Injection Pump (2-SI-P-1B)," Revision 57
- 1-PT-57.1B, "Emergency Core Cooling Subsystem Low Head Safety Injection Pump (1-SI-P-1B)," Revision 51
- 2-PT-71.1Q, "2-FW-P-2 Turbine Driven Auxiliary Feedwater Pump and Valve Test," Revision 51

RCS Leakage:

- 2-PT-52.2A, "Reactor Coolant System Leak Rate (Computer Calculation)," Revision 35

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On July 20, 2010, the inspectors reviewed and observed the performance of an emergency planning that involved a turbine runback, loose parts alarms for the reactor vessel, a steam generator tube rupture, and various equipment failures resulting in an Alert and subsequent Site Area Emergency followed by a General Emergency. The inspectors assessed emergency procedure usage, emergency plan classification, notifications, and the licensee's identification and entrance of any problems into their corrective action program. This inspection evaluated the adequacy of the licensee's conduct of the drill and critique performance. Exercise issues were captured by the licensee in their corrective action program as multiple CRs listed in the attachment. Requalification training deficiencies were captured within the operator training program.

b. Finding

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors performed a periodic review of the five following Unit 1 and 2 performance indicators to assess the accuracy and completeness of the submitted data and whether the performance indicators were calculated in accordance with the guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspection was conducted in accordance with NRC Inspection Procedure 71151, "Performance Indicator Verification." Specifically, the inspectors reviewed the Unit 1 and Unit 2 data reported to the NRC for the period July 1, 2009 through June 30, 2010. Documents reviewed included applicable NRC inspection reports, licensee event reports, operator logs, station performance indicators, and related CRs.

Mitigating Systems Performance Index (MSPI)

- High Pressure Injection System
- Emergency AC Power System
- Support Cooling Water System
- Residual Heat Removal System
- Auxiliary Feedwater System

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems

.1 Review of Items Entered into the Corrective Action Program

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished by reviewing daily CR report summaries and periodically attending daily CR Review Team meetings.

.2 Annual Sample: Review of CR354854, Air Leaking from Diaphragm While Stroking 1-CH-HCV-1200C, and CR387916, 1-RC-PCV-1456 Failed to Open with Keyswitch in Open

a. Inspection Scope

The inspectors reviewed the licensee's assessments and corrective actions for Condition Report (CR) 354854, "Air leaking from diaphragm while stroking 1-CH-HCV-1200C" and

CR387916, “1-RC-PCV-1456 failed to open with keyswitch in open”. The condition reports were reviewed to ensure that the full extent of each issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors also evaluated the condition reports against the requirements of the licensee’s corrective action program as specified in PI-AA-200, “Corrective Action”, Revision 12, and 10 CFR 50, Appendix B.

b. Findings

Introduction: An apparent violation (AV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," was identified by the inspectors for two examples of the failure to promptly identify and correct a condition adverse to quality present in the actuator diaphragms of 1-CH-HCV-1200C and 1-RC-PCV-1456.

Description: The first example occurred on October 26, 2009 when the licensee identified air leaking from the actuator diaphragm of 1-CH-HCV-1200C and initiated CR354854, “Air leaking from diaphragm while stroking 1-CH-HCV-1200C” and CR355000, “Failed diaphragm found torn at bolt holes” to document the condition. The second example occurred on July 15, 2010 when pressurizer power operated relief valve (PORV) 1-RC-PCV-1456 failed to open on demand and the licensee initiated CR387916, “1-RC-PCV-1456 failed to open with keyswitch in open” to document the condition. At the time of their failure each of these valve actuators were in the licensee’s CAP as requiring diaphragm replacement due to the presence of improperly drilled actuator bolt holes and overtorqued actuator casing bolts.

The licensee had previously experienced an air operated valve (AOV) diaphragm failure in March 2009 with the failure of pressurizer PORV 1-RC-PCV-1455C due, in part, to improperly drilled actuator bolt holes and overtorqued actuator casing bolts. The failure of 1-RC-PCV-1455C and the technical aspects of improperly drilled actuator bolt holes and overtorqued actuator casing bolts are discussed in NRC integrated inspection report 05000338, 339/2009003. The inspectors reviewed licensee Apparent Cause Evaluation (ACE) 017534, “ACE to Eng to investigate the failed 1-RC-PCV-1455C diaphragm” and Operability Determination (OD) 000283, “Create OD to document the operability of associated components”, Revisions 0, 1, 2, and 3. OD000283 was revised following each of the subsequent AOV diaphragm failures. The inspectors also reviewed Root Cause Evaluation (RCE) 01021, “1-RC-PCV-1456 diaphragm failure”. The inspectors determined that 1-CH-HCV-1200C and 1-RC-PCV-1456 were identified in April 2009 as having an actuator diaphragm with additional bolt holes drilled and over torqued casing bolts. The inspectors also determined that each failure was the result of over torqued casing bolts or the drilling of additional bolt holes.

The inspectors concluded that the presence of a drilled, over torqued actuator diaphragm in 1-CH-HCV-1200C and 1-RC-PCV-1456 were known conditions adverse to quality. The inspectors also concluded that the licensee failed to promptly correct this condition adverse to quality, as required by 10 CFR 50, Appendix B, Criterion XVI, and that this resulted in the failure of 1-CH-HCV-1200C and 1-RC-PCV-1456.

Analysis: The inspectors determined that the failure to promptly correct conditions adverse to quality for 1-CH-HCV-1200C and 1-RC-PCV-1456 was a PD. The NRC Enforcement Manual allows for the grouping of multiple examples of the same violation during an inspection period and the assignment of an issue to that example which is most significant. The inspectors determined that the second example, involving 1-RC-PCV-1456, was the more significant issue. The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to examples 4d and 4f in that the failure to correct a condition adverse to quality led to the inoperability of the component. The inspectors reviewed IMC 0609, Appendix B, and determined that the finding was also more than minor because it affected the Barrier Integrity cornerstone objective or providing reasonable assurance that physical design barriers (e.g. RCS) protect the public from radionuclide releases caused by accidents or events. Specifically, RCS equipment and barrier performance, in that the pressurizer PORVs provide protection to the RCS by preventing brittle fracture at low temperature conditions and protect RCS integrity at high temperatures. The inspectors reviewed IMC 0609, Attachment 4, and determined that since the finding involved a degradation of the Barrier Cornerstone, specifically the RCS barrier, a phase 3 analysis was required. The significance of this finding is to be determined pending completion of the phase 3 evaluation. The cause of this finding involved the cross-cutting area of problem identification and resolution, the component of corrective action program, and the aspect of implementation of corrective action, P.1(d), because the licensee failed to correct the safety issue that existed with 1-RC-PCV-1456 in a timely manner, commensurate with its safety significance and complexity.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, on July 15, 2010, the licensee failed to promptly correct a known condition adverse to quality involving 1-RC-PCV-1456 which resulted in the failure of the valve to open on demand. Pending determination of safety significance, this finding is identified as AV 05000338/2010004-02, Failure to Promptly Correct Conditions Adverse to Quality for Valve Actuator Diaphragms.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 05000339/2010-001-00: Automatic Reactor Trip and ESF Actuation during Automatic Voltage Regulator Testing Due to Inadequate Procedure Guidance

a. Inspection Scope

On April 27, 2010, with Unit 2 operating in Mode 1 at 74% power during recovery from a refueling outage, an automatic reactor trip occurred caused by a turbine trip due to a generator lockout. The direct cause of the generator lockout protective relay actuation was the incorrect software curve set points derived from the voltage regulator Minimum Excitation Limiter (MEL) tuning software. The MEL acts by modifying the automatic voltage regulator's (AVR) output to keep from exceeding the main generator's lower operating limit. The software setting errors in the MEL tuning utility for North Anna Unit 2

AVR were corrected and testing on the new AVR was successfully completed. This LER is closed.

b. Findings

.1 Failure to Conduct Adequate Review of Calculation Results in Main Turbine/Reactor Trip.

Introduction: A Green, self-revealing finding was identified for the licensee's failure to conduct an adequate review of calculations for the operation of the Unit 2 main generator AVR, as required by licensee procedure CM-AA-CLC-301, "Engineering Calculations," Revision 3, which resulted in the actuation of a main generator protective lockout relay and subsequent main turbine/reactor trip.

Description: On April 27, 2010, Unit 2 was operating at 74% power during testing of the Unit 2 main generator AVR, which was installed during the most recent refueling outage. Upon initiation of AVR tuning at this power level, a main generator protective lockout relay actuated resulting in a turbine trip and subsequent reactor trip. The licensee entered this event into their CAP as CR378800. The inspectors reviewed the associated RCE001007, interviewed licensee personnel, and reviewed licensee documentation related to the installation and testing of the AVR.

The inspectors reviewed RCE001007 and noted that it revealed the AVR minimum excitation limiter (MEL) tuning software defaulted to the use of a five point curve for MEL and minimum excitation protection (MEP) setpoints. This was different than the circular curve used to determine the MEL/MEP setpoints during normal operation. The inputs for the five point curve were not commensurate with the ratings of the Unit 2 main generator; instead they were significantly smaller. The AVR setting used to determine which curve would be used, five-point or circular, was set for a circular curve, which had the correct inputs. Upon initiation of the MEL tuning software at 74% power, and the default of the software to the incorrect five-point curve, the generator was operating below the MEP setpoint thus causing actuation of a main generator protective lockout relay and subsequent turbine/reactor trip. The inspectors noted that the licensee had internally questioned the incorrect inputs for the five-point curve; however, they did not directly question the external engineering organization that provided them or follow back to source documentation to verify their accuracy or intended use.

The inspectors reviewed licensee calculation EE-0826, "North Anna Unit 2 Main Generator Voltage Regulator Settings," Revision 0, and noted that it included variable settings for the control/protective features of the AVR, as well as other utilities, including the MEL tuning software. The inspectors noted that the calculation contained two variables (mw_curve and var_curve) which contained values for the ratings of a generator significantly smaller than that used for the Unit 2 main generator, and were used to generate the five-point curve used in the MEL tuning software. The inspectors identified that EE-0826 was approved using licensee procedure CM-AA-CLC-301, "Engineering Calculations", Revision 3. The inspectors also identified that the calculation was signed for as originated, reviewed, and approved by external engineering organizations and that licensee personnel signed for owner's approval.

The inspectors identified that for acceptance of vendor calculations CM-AA-CLC-301 Section 3.7 requires the licensee to “Perform an Owner’s Review. The Dominion representative shall perform the owner’s review in accordance with DNES-AA-GN-1001”. The inspectors identified that nuclear engineering standard DNES-AA-GN-1001, “Engineering Review”, Revision 0, Section 3.5 states that the owner’s review is “a review performed by Dominion that verifies engineering deliverables, provided by an external engineering organization, fulfill requested services” and that this is accomplished by confirming that “any affected documents and operational impacts were identified”, “key assumptions and inputs properly reflect the intended end use”, and “conclusions appear to be consistent with the inputs and assumptions used”. Through interviews with licensee personnel, the inspectors identified that the licensee did not use nuclear engineering standard DNES-AA-GN-1001 to conduct the owner’s review. The inspectors determined that the guidance for conducting an owner’s review contained in DNES-AA-GN-1001 could have reasonably identified the intended end use of the incorrect inputs.

The inspectors concluded that the licensee failed to conduct an adequate owner’s review of calculation EE-0826 in that they failed to meet the requirements of CM-AA-CLC-301 to conduct an owner’s review in accordance with DNES-AA-GN-1001 and that this failure resulted in the actuation of a main generator protective lockout relay and subsequent main turbine/reactor trip.

Analysis: The inspectors determined that the failure to conduct an adequate owner’s review of calculation EE-0826, as required by licensee procedure CM-AA-CLC-301, “Engineering Calculations,” Revision 3, was a PD. The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to example 4.b in that the procedural error resulted in a reactor trip or other transient. In addition, the inspectors determined that it adversely impacted the Initiating Events cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations, specifically the attribute of Design Control in that the AVR design change was not properly controlled and Human Performance in that licensee personnel conducting the owner’s review failed to follow the requirements of CM-AA-CLC-301 and conduct an owner’s review of calculation EE-0826. The inspectors reviewed IMC 0609 Attachment 4 and determined that the finding was of very low safety significance, or Green, because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The cause of this finding involved the cross-cutting area of human performance, the component of decision making, and the aspect of conservative assumptions and safe actions, H.1(b), because the licensee failed to use conservative assumptions and demonstrate that the proposed action was safe in making the decision that the incorrect inputs for the five-point curve would not be used by the MEL tuning software.

Enforcement: This finding does not represent a violation of regulatory requirements; therefore, enforcement action does not apply. Licensee procedure CM-AA-CLC-301 requires, in part, that for the acceptance of vendor calculation the licensee shall perform an owner’s review in accordance with DNES-AA-GN-1001. Contrary to this, on April 27, 2010 the licensee failed to conduct an adequate owner’s review of calculation EE-0826 and this failure resulted in the actuation of a main generator protective lockout relay and subsequent main turbine/reactor trip. Because this finding does not involve a violation of regulatory requirements, has very low safety significance (Green), and has been entered into the licensee's CAP as CR378800, it is being treated as a Finding, FIN 05000339/2010004-03, Failure to Conduct Adequate Review of Calculation Results in Main Turbine/Reactor Trip.

.2 Failure to Correctly Translate Turbine Driven Auxiliary Feedwater Pump Design Basis into Specifications or Drawings

Introduction: A self-revealing, Green NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified for the failure to correctly translate the design basis of the Unit 2 turbine driven auxiliary feedwater pump (TDAFWP) lube oil subsystem vent into specifications or drawings.

Description: On April 27, 2010, following a Unit 2 reactor trip, the licensee received an AFW pump trouble or lube oil trouble alarm. Operator investigation found oil spraying from the TDAFWP lube oil reservoir sight glass and pump oil bearing housings, at which time the TDAFWP was secured. The licensee entered this issue into their CAP as CR 378798, "2-FW-P-2 was secured after auto start due to oil leak" and initiated ACE018148, "2-FW-P-2 was secured after auto start due to oil leak" to investigate the failure and institute corrective action. Subsequent investigation revealed that the TDAFWP lube oil reservoir had become pressurized during operation due to the absence of an adequate vent path in the system. This pressure forced oil out of the system at the lube oil reservoir sight glass and the pump oil bearing housings, which continued until the TDAFWP was secured. Corrective action taken by the licensee included re-installation of a vent in the unit 2 TDAFWP lube oil reservoir, verification of a vent in the unit 1 TDAFWP lube oil reservoir, and updating of station drawings to include the vents on both units. The inspectors reviewed CR378798 and ACE018148, other licensee documentation, and interviewed licensee personnel.

The inspectors determined that in 1993 licensee ET-ME93-009, authorized the removal of the unit 2 TDAFWP lube oil reservoir vent to mitigate water intrusion because the vent was "undocumented and is not part of the original design" and "the system requires venting according to the pump manufacturer" which was achieved "through the six bearing vents". The inspectors also determined that in 1995 the licensee replaced the unit 2 TDAFWP bearing seals with a zero leakage style under item equivalency evaluation report (IEER) N-95-5022-000. In reviewing IEER N-95-5022-000 the inspectors noted that it reviewed station drawings and contained no evaluation of the vent function of the bearings that were removed. In April 2010, the licensee completed WO59101877786, "Carbon gland housing leak out board end of turbine", to seal leaks on the bearing housings. The licensee's investigation determined that this maintenance sealed an inadvertent vent path that had been masking the inadequate venting of the system that existed from 1995 until 2010.

The inspectors interviewed licensee personnel and determined ET-ME93-009 was incorrect in that, the lube oil reservoir vent was part of the original TDAFWP design and a vent was present in the unit 1 TDAFWP lube oil reservoir. The inspectors interviewed licensee personnel, reviewed licensee documentation and station drawings, and determined that the licensee failed to correctly translate this design requirement into specifications, drawings, procedures, and instructions. The inspectors concluded that this failure led to a lube oil leak in the system and the licensee's securing of the TDAFWP during a demand run.

Analysis: The inspectors determined that the licensee's failure to correctly translate the Unit 2 TDAFWP lube oil subsystem vent into specifications or drawings as required by Criterion III was a PD. The inspectors reviewed IMC 0612, Appendix E and determined the PD was more than minor, because it was similar to examples 3b and 3k in that the failure to correctly translate the design into drawings adversely impacted the operation of the system and resulted in reasonable doubt about the operability of the system. The inspectors reviewed IMC 0609 Attachment 4 and determined that the finding was of very low safety significance, or Green, because the finding was a design or qualification deficiency confirmed not to result in loss of operability or functionality. The cause of this finding did not involve a cross-cutting aspect because it is not indicative of current licensee performance.

Enforcement: 10 CFR 50, Appendix B, Criterion III, "Design Control," states in part that, measures shall be established to assure that the design basis is correctly translated into specifications or drawings. Contrary to the above, on April 27, 2010, the licensee failed to correctly translate the design basis for the unit 2 TDAFWP lube oil subsystem vent into specifications or drawings which resulted in a lube oil leak in the system and the licensee's securing of the TDAFWP during a demand run. Because the finding is of very low safety significance (Green) and it was entered into the licensee's CAP as CR378798, this violation is being treated as an NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000339/2010004-04, Failure to Correctly Translate Turbine Driven Auxiliary Feedwater Pump Lube Oil Subsystem Vent Design Basis into Specifications or Drawings.

.3 (Closed) Licensee Event Report (LER) 05000339/2010-003-00: Failure to Isolate Primary Grade Water to Blender due to Operator Activities

On May 28, 2010, a reactor trip occurred on Unit 2 at 0004. From 0014 to 0027 on May 28, 2010, the licensee conducted a primary grade (PG) water make-up to the blender while also conducting emergency and abnormal operating procedures related to the reactor trip. The supply valve for PG water to the blender was not secured closed until 0104 on May 28, 2010. Technical Specification (TS) Limiting Condition for Operation (LCO) 3.1.8 requires that valves used to isolate PG water flow paths be secured in the closed position while the unit is in Modes 3, 4, or 5. TS LCO 3.1.8 allows for the opening of PG water flow path isolation valves under administrative control for planned makeup activities, however, these valves must be secured closed within 15 minutes of the completion of such activities. Contrary to this, from 0042 until 0104 on May 28, 2010 the licensee failed to secure closed the supply valve for PG water to the blender. This issue was captured in the licensee's CAP as CR382750. The inspectors determined that this failure to secure closed the supply valve for PG water to the blender was a PD. The inspectors reviewed IMC 0612 Appendix B and Appendix E, and determined that the PD was minor because there were no safety consequences and, if left uncorrected, the PD did not have the potential to lead to a more significant safety concern. This failure to comply with TS 3.1.8 constitutes a violation of minor significance that is not subject to enforcement action in accordance with the NRC's Enforcement Policy. Documents reviewed are listed in the Attachment. This LER is closed.

.4 (Closed) Licensee Event Report (LER) 05000339/2010-002-00: Automatic Reactor Trip and Engineered Safety Feature Actuation Due to Lightning Strike

a. Inspection Scope

The inspectors conducted a review of licensee activities to follow up on a reactor trip which occurred on May 28, 2010. The inspector performed the following:

- reviewed and evaluated ERT's report,
- discussed report details with members of the ERT and others,
- reviewed supplementary documents such as control circuits, equipment instruction manuals, calculations, and motor data,
- reviewed application of undervoltage relays involved in the event
- toured switchyard and transformer areas related to the event.
- in-office review of the root cause analysis and the LER

Documents reviewed are listed in the Attachment to this report. This LER is closed.

b. Findings

Introduction: A Green self-revealing finding was identified for the failure to establish an adequate set point for a balance-of-plant 4160 V bus undervoltage protection relay. The inadequate set point caused a reactor trip upon automatic start of a steam generator feedwater pump.

Description: The reactor trip event revealed that the undervoltage protection relays at a station service bus could have actuated upon start of a feedwater pump selected for standby mode due to the motor starting voltage dip. A Unit 2 reactor trip can occur if reserve station service transformer (RSST) B is automatically de-energized and feedwater pump B is selected as the standby pump. A Unit 2 reactor trip will not occur if RSST A or C is automatically de-energized. A Unit 2 reactor trip will not occur if RSST B is de-energized and feedwater pump A or C is selected as the standby pump. Except for the loss of reactor coolant pump loads, loss of loads on one station service bus would not result in a reactor trip. The problem can occur on Unit 1 if RSST C is lost and feedwater pump C is selected for standby. The problem can also manifest itself upon a feedwater pump trip, because that would lead to a true high differential pressure, but the standby pump may not start as intended to avert the trip.

The undervoltage protection relays (27 devices) were NGV 15A21 style relays as manufactured by General Electric Co., which are definite voltage hinged-armature telephone type relays. The undervoltage relays worked in conjunction with a SAM style relay manufactured by General Electric Company, which is a solid state timing relay, set at 0.33 seconds. The purpose of the 0.33 second time delay is to coordinate with overcurrent protection and to remain secure during a fast transfer. Two potential transformers were connected in open delta configuration across phases A-B and B-C to station service bus 2B. One NGV relay was connected in the secondary of each potential transformer. The tripping logic was two-out-of-two. At the time of the event, the undervoltage relays were set at 3043 V and had an uncertainty band of 2900 V to 3187 V. Voltage recorders showed that the voltage at station service bus 2B dipped to 3013 volts (approximately) upon starting the standby feedwater pump, which was below the set point of the undervoltage relays and this dip would have lasted longer than 0.33 seconds. What happened during the event was that the standby feedwater pump attempted to start, both undervoltage relays actuated, a trip signal was given to the incoming circuit breaker and all motor feeder circuit breakers, except the reactor coolant pump. In general, whenever the incoming circuit breaker trips on a signal from the undervoltage relays the alternate supply circuit breaker receives a close signal and the reactor coolant pump is transferred.

When a feedwater pump is started during plant startup, the two motors are started sequentially not simultaneously. This explains why the undervoltage relay actuation did not occur during a normal startup. The voltage dip to 3013 V represents 75 percent of motor rated voltage, and the feedwater pump motors were designed to start at 75 percent voltage. Therefore, they would have started if the undervoltage relay had not actuated. The voltage dip to 3013 V matches well with computer based motor starting voltage dip calculations.

In March 2007 a similar event occurred, RSST B de-energized and the standby feedwater pump at Unit 2 started. In that event, the undervoltage relays did not actuate. Voltage data from the March 2007 event showed that voltage had dropped to 2914 V. The fact that the undervoltage relays did not actuate was explained by the uncertainty band of the relay set point and the two-out-of-two logic. The inspector reviewed records of undervoltage relay calibration data, and he observed that the data sheets did not contain as-found set point data. Therefore, it could not be determined from review of calibrations records whether or not the relays had a tendency to drift out of the expected range between calibrations.

The licensee had already taken two corrective actions based on the recommendations of the ERT. The set point of the automatic tap changers at Unit 2 station service buses was adjusted to maintain a higher voltage on those buses, which they believe will result in the voltage dropping to a value somewhat above that seen in past events. Second, the set point of the undervoltage relays was changed from 3043 V to 2912 V, which should decrease the probability that the set point will be reached upon feedwater pump motor starting. Both these set point changes do not make the undervoltage relay set point secure in the face of feedwater pump starting, they only decrease the probability of a relay actuation. The problem with using the NGV relay in this particular application is that it has a tolerance band of at least 4.7 percent and, licensee engineers stated, the set point has a tendency to drift with temperature changes that occur in the turbine building. After the event, the licensee calibrated the relays which had actuated, and found that the set point was at the upper limit of the expected range. Given the fact that the relays had been calibrated one month earlier, set point drift may be a problem with these relays. According to cognizant licensee engineers, the long term solution was to determine the motor stall voltages and select a new relay with a tighter uncertainty band (perhaps 1 percent) which can be set above the motor stall voltages and below the motor starting voltage dip of the feedwater pump motor.

Another corrective action under consideration by the licensee was to change the logic of the pressure differential auxiliary relay from “de-energize to start” the feedwater pump to “energize to start” the feedwater pump. There does not appear to be any reason to have fail-safe operation for this circuit. With “energize to start” logic, the feedwater pump would not receive a spurious start on loss of RSST B (or RSST C on Unit 1).

Analysis: The fact that the motor starting voltage dip of the twin 4500 horsepower motor feedwater pump was below the set point of the bus undervoltage protection relays was a PD. The typical industry standard practice for bus undervoltage is that the set point be below the motor starting voltage dip to preclude spurious actuation of the undervoltage relays for expected voltage transients such as motor stating. This industry standard practice is documented in Institute of Electrical and Electronics Engineers Standard 666-1991, “IEEE Design Guide for Electric Power Service Systems for Generating Stations.” Table 7.2, “Motor Protection Devices,” states that the suggested setting for undervoltage relay is that it be set to override voltage drop due to motor starting. The potential for spurious tripping of the undervoltage relays has nuclear safety ramifications, in that it can contribute to a reactor trip, as it did on May 28, 2010. The PD was more than minor because it was associated with the attribute of design control and adversely affected the objective of the initiating event cornerstone. The inappropriate undervoltage relay set point contributed to a reactor trip which is an event that upset plant stability and challenged critical safety functions. The finding was evaluated for significance using IMC 0609, Appendix E. The finding was determined to be very low safety significance, Green, because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation functions will not be available. The cause of the finding was evaluated in the licensee’s corrective action program as RCE001012. According to the LER and RCE001012, the cause of the finding was determined to be lack of a design basis for the undervoltage protection relay. Since the set point was established well outside the two-year window of current performance and there was no prior event that provided an opportunity to identify this problem, this issue did not represent current licensee performance. Therefore, no associated cross-cutting aspect was identified.

Enforcement: Enforcement action does not apply because the finding did not involve a violation of regulatory requirements. Because this finding was entered into the license’s corrective action program as RCE001012, and has very low safety significance, it is identified as Finding (FIN) 05000338, 339/2010004-05, “Inadequate Set Point for Balance of Plant Bus Undervoltage Relay.”

.5 1-CH-LCV-1115A Failure

a. Inspection Scope

The inspectors reviewed the licensee’s response to the failure of 1-CH-LCV-1115A, reactor coolant filter letdown to volume control tank level control valve, which occurred on August 5, 2010. During maintenance activities associated with this valve, the valve failed in the full divert position which resulted in 75 gpm of RCS letdown flow being diverted to the boron recovery system for a period of 3 minutes until RCS letdown flow was isolated. During this time the 75 gpm leak rate was in excess of the entry threshold for a Notice of Unusual Event of the licensee's Emergency Action Levels. The inspectors monitored the licensee's action during the event. The inspectors also discussed the event with operations, engineering, and licensee management personnel to gain an understanding of the event and assess follow up actions. The inspectors reviewed operator actions taken in accordance with licensee procedures and reviewed unit and system indications to verify that actions and system responses were as expected. The inspectors also reviewed the initial licensee notifications to verify that the requirements specified in NUREG-1022, "Event Reporting Guidelines" were met.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with the licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings were identified.

.2 Review of the Operation of an Independent Spent Fuel Storage Installation (Inspection Procedure 60855.1)

a. Inspection Scope

Inspectors reviewed the normal operation of the Independent Spent Fuel Storage Installation (ISFSI). The inspectors walked down the ISFSI pad to assess the material condition of the casks, the installation of security equipment, and the performance of monitoring systems. The inspectors verified by direct observation of selected activities and independent evaluation that the licensee has performed cask loading in a safe manner and in compliance with approved procedures.

b. Findings

No findings were identified

.3 Unit 2 Automatic Reactor Trip During a Lightning Storm

a. Inspection Scope

An apparent violation (AV) 05000339/2010003-03, Failure to Follow Procedure to Trip ‘A’ Reactor Coolant Pump on High Bearing Temperature, was documented in NRC Integrated Inspection Report 05000338/2010003, 05000339/2010003, AND 07200056/2010001. A NRC regional senior risk analyst (SRA) completed the significance determination which allowed closure of the AV to a NCV discussed below.

b. Findings

Introduction: A Green, NCV of TS 5.4.1a was identified by the inspectors for the failure to adequately implement procedural requirements resulting in operation of the Unit 2 ‘1A’ RCS pump (‘A’ RCP) beyond the motor high bearing temperature limit of 195 degF for approximately 10 minutes.

Description: On May 28, 2010, at 0004 hours a lightning strike resulted in a loss of power to the ‘B’ reserve station service transformer (RSST) and consequent loss of power to the downstream ‘2H’ emergency bus and semi-vital bus. This resulted in a start of the standby main feedwater pump due to loss of feedwater pressure instrumentation and consequent low voltage on ‘2B station service bus (SSB) which also feeds the ‘B’ RCP. Undervoltage relays on the ‘2B’ SSB resulted in a fast transfer attempt to the ‘B’ RSST which was already de-energized. This caused loss of power to the ‘B’ RCP and subsequent reactor trip. The loss of power to the 2H emergency bus also resulted in a loss of power to and closure of the component cooling (CC) trip valves for the RCP motors and resultant alarms, “RCP 1A [B,C] CC Return Lo Flow.”

The inspectors reviewed the related alarm response procedure for RCP 1A CC Return Lo Flow, 2-AR-C-C1, Revision 1, and noted the following steps:

- Step 1.5 identified a probable cause for the alarm as a loss of power to respective CC trip valves
- Step 2.4 states, “IF CC is lost to pump and motor bearings exceed 195°F or pump bearings exceed 225°F, THEN GO TO 2-E-0, Reactor Trip or Safety Injection AND trip the RCP.”
- Step 2.5 also refers the operator to 2-AP-15, “Loss of Component Cooling,” Revision 18, of which step 10 requires in part for the operator to monitor RCP temperatures, motor bearing temperature less than 195 degF. The response not obtained column requires the operator to go to 2-E-0, “Reactor Trip or Safety Injection,” and when the reactor is tripped then stop affected RCPs

The inspectors noted that CC was lost to the RCP motors on loss of power to the 2H emergency bus at ~0004 hours. The inspectors reviewed the respective times from the plant computer system (PCS) at which the first 'A' RCP motor bearing exceeded 195 degF and noted the upper thrust bearing temperature exceeded 195 degF at ~0021 hours. The inspectors also noted the 'A' RCP motor was not tripped until ~0031 hours, and the upper thrust bearing temperature peaked at ~221.7 degF approximately one minute later but did not return to less than 195 degF until ~0135 hours.

The inspectors reviewed the vendor's RCP manual for information regarding the potential impact of RCP motor bearing degradation on the pump seals and identified documentation in Addenda 19 that indicated that one of the major causes of seal failures is high vibration. The inspectors interviewed engineering personnel who noted that the Babbitt is ~.375 inches thick on the thrust and radial bearings. The inspectors determined that melting of the Babbitt on bearing surfaces yields increased bearing to shaft clearances and a consequent increase in vibration. The licensee entered this problem into their corrective action program as corrective action 170278 associated with condition report 382725.

Analysis: A PD was identified by the inspectors for the failure to adequately implement procedural requirements of 2-AR-C-C1 to trip the 'A' RCP in response to motor bearing temperatures exceeding 195 degF. This PD had a credible impact on safety due to the operation of the 'A' RCP beyond the vendor's analysis for adequate, long term component safety. The PD was more than minor and therefore a finding, because it could be reasonably viewed as a precursor to a significant event due to RCP motor operation in an unknown condition of bearing performance in which the melting of Babbitt material can lead to excessive shaft vibrations and consequent adverse impact on RCP seal performance leading to a seal loss of coolant accident. Significance determination process (SDP) phase 1 screening determined the finding to be a primary system loss of coolant accident (LOCA) initiator contributor as RCP operation without motor bearing cooling could lead to motor bearing failure, RCP vibration and potential vibration induced RCP seal damage. The finding was determined to fit under the Initiating Events cornerstone in that assuming worst case degradation the potential seal leakage could exceed the technical specification limit for RCS leakage and required phase 2 analysis. Since the North Anna SDP pre-solved worksheet did not specifically address loss of cooling to the RCP motor bearings, a phase 3 analysis was performed by a regional SRA using the NRC's North Anna SPAR model. The sequence was a reactor trip transient caused by a lightning strike in the switchyard, loss of the 1H emergency bus, RCP motor bearing damage due to loss of bearing cooling, failure to trip the RCP, RCP seal failure, failure of high pressure injection, successful depressurization and failure of low pressure injection leading to core damage. A diagnosis and action human error probability for RCP trip was developed for the event conditions. The risk of the event was mitigated by the availability of seal cooling, seal injection and the time and cues available to the operator to trip the RCP prior to vibration induced seal failure. The phase 3 risk evaluation determined that the risk increase of the finding was <1E-6 for core damage frequency and <1E-7 for Large Early Release Frequency, a finding of very low risk significance (GREEN). This finding involved the cross-cutting area of human performance, the component of decision making and the aspect of decision communications, H.1(c), because a reactor operator failed to communicate the loss of component cooling to the RCP motors to the senior reactor operator which led to the failure to trip the ‘A’ RCP on exceeding the motor bearing high temperature limit.

Enforcement: TS 5.4.1a requires, in part, that written procedures shall be implemented per Regulatory Guide 1.33, Appendix A, of which part 5 specifies procedures for abnormal, off-normal, or alarm conditions. Contrary to this, on May 28, 2010, the licensee failed to adequately implement procedural requirements in 2-AR-C-C1 resulting in operation of the ‘A’ RCP beyond the motor high bearing temperature limit of 195 degF for approximately 10 minutes. Because this finding is of very low safety significance and because it was entered in the licensee’s corrective program as corrective action 170278, this violation is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy: NCV 05000339/2010004-06, Failure to Follow Procedure to Trip ‘A’ Reactor Coolant Pump on High Bearing Temperature.

.4 (Closed): URI 05000338/2010002-02, Safety-Related Breaker Cubicle Fire Issue

Introduction: The inspectors had previously opened URI 05000338/2010002-02, Safety-Related Breaker Cubicle Fire Issue, in NRC Integrated Inspection Report 05000338/2010002 and 05000339/2010002, based on a fire in a safety related breaker cubicle. A self-revealing finding was identified for the failure to maintain PM procedures for circuit breakers current with industry information and OE, as required by procedure, DNAP-2001, “Equipment Reliability Process,” Revision 0. The significance of this finding is to be determined pending completion of the phase 3 evaluation.

Description: On April 22, 2009, a licensee operator, who was escorting several fire watch personnel to instruct them on which areas to patrol due to the removal from service of area fire detectors, noticed an odor from an electrical fire located in the Unit 1 cable vault area. The source of the fire was located at the safety-related breaker cubicle, 01-EE-BKR-1J1-2S-J1, for ‘D’ control rod drive mechanism (CRDM) fan. The operators obtained a carbon dioxide (CO_2) fire extinguisher, opened the cubicle and observed flame and smoke, and extinguished the fire with CO_2. A visual examination of the breaker revealed that the molded case circuit breaker (MCCB) and main contactor had experienced the most damage.

The licensee initiated CR331819 and the associated root cause evaluation (RCE) 000976 in accordance with their CAP. A vendor examination of the breaker components was also performed to determine the cause of the fire and was completed in December, 2009. The inspectors reviewed RCE000976 and respective vendor analysis and found the following information:

- The direct cause of the fire was overheating of the main contactor coil due to age related insulation degradation between the windings of the coil. This component was original equipment and in service approximately 35 years.
- The root cause was a failure to implement an appropriate preventative maintenance (PM) program for replacement of main contactors (also known as motor starters) and the contributing cause was a lack of appropriate predictive maintenance.

- The historical, similar breaker events involving a fire had no failures associated with the age-related failure of a main contactor.
- The extent of cause involves all coils installed for greater than 35 years and includes breakers of other manufacturers installed in the plant.

The inspectors performed an independent review of historical events to determine if there were other opportunities for the licensee to previously identify problems with age related failure of main contactor coils. The inspectors identified Plant Issue N-2006-1877 which documented an event on March 31, 2006, involving smoke coming from non-safety related breaker cubicle, 1-EP-MCC-1C2-2-B1-CKTBRK, for turbine building exhaust fan, 1-HV-F-29J, and the activation of the station's fire brigade. Troubleshooting determined the failure was a burned coil in the 52 relay or main contactor. The inspectors noted the cause was documented as normal age related degradation, and there were no additional corrective actions because enhancements to PM procedures had added numerous detailed inspections of all components in the modules. The inspectors reviewed the following licensee program procedures for information concerning the establishment and maintenance of PM procedures.

Licensee procedure, ER-AA-BKR-1001, effective April 5, 2007, contains the following information: Step 3.2.1 states that "Routine preventive maintenance (PM) shall be performed on all circuit breakers in the Dominion Circuit Breaker Program. A PM task shall be established for each circuit breaker in the Program. PM requires minimal or no disassembly, and is performed to ensure a circuit breaker is in good operating condition and that it will operate reliably until the next scheduled maintenance. Routine preventive maintenance is also used to monitor the condition of the breaker and correct any minor problems or degradations."

Licensee procedure, VPAP-0817, "Circuit Breaker and Associated Switchgear Maintenance Program," Revision 0, effective September, 2001, contains the following information:

- Step 4.2 includes in part in the circuit breaker definition a discussion of a circuit breaker assembly that consists of items such as control circuit components and primary/secondary disconnect devices.
- Step 6.1.1 states in part that because of normal aging of circuit breaker material and lubricants a PM program shall be established to ensure circuit breaker operability and reliability.
- Step 6.1.5 states in part that components housed in the same cubicle shall be cleaned and tested at the time of the MCCB maintenance; examples of this include contactors (motor starters).

Licensee procedure, DNAP-2001, "Equipment Reliability Process," Revision 0, effective March, 2003, states in step 3.4.2, "Preventive Maintenance Program," that the Preventive Maintenance Program is a living program, with a documented technical basis for each PM. Each PM basis shall be kept current based on operating experience, corrective action reviews, and PM feedback.

Licensee procedure, DNAP-0104, "Dominion Nuclear Self-Assessment Program," Revision 0, effective March, 2003, states in step 5.3.5, "Industry Standards," that criteria for a program or process for which the majority of the industry uses or is considered to be an acceptable level of performance. These standards can be obtained from documents describing an acceptable program such as those written by INPO, NEI, EPRI, or industry work groups (e.g., Westinghouse Owners Group). Step 5.3.11, "Operating Experience," states in part that OE is any lessons learned information made available from the nuclear or other industry.

The inspectors performed a search of industry programs to determine the availability of operations experience and preventative maintenance program information relative to main contactors and identified several EPRI technical reports and a Sandia Laboratory report which specifically addressed Klockner-Moeller breakers and related component failures as noted below: EPRI TR-106857, Volume 4: Motor Control Centers, July, 1997; EPRI TR-107042, Improving Maintenance Effectiveness, March, 1998; EPRI TR-1000806, Demonstration of Life Cycle Management Planning for Systems, Structures, and Components, January, 2001; EPRI TR-1009832, Molded Case Circuit Breaker Application and Maintenance Guide, Revision 2, December, 2004; and SAND93-7069, Aging Management Guideline for Commercial Nuclear Power Plants – Motor Control Centers, February, 1994.

The inspectors reviewed the licensee's electrical PM procedure, 0-EPM-0304-01, "Testing/Replacing 480-Volt Breaker Assemblies," Revision 49, performed during the last PM for 01-EE-BKR-1J1-2S-J1 on September 21, 2007, and Revision 56, which was in effect at the time of the fire event in 2009. The inspectors noted that 0-EPM-0304-01, step 6.4, "Breaker Module Inspection," stated in part to check each relay coil for continuity and freedom of movement and motor starter contacts for continuity. When compared to available industry information, the inspectors concluded that 0-EPM-0304-01 did not contain guidance to test the main contactors to detect degradation of the respective coil winding, and that adequate time existed for the licensee to follow their aforementioned program requirements stated in procedures, ER-AA-BKR-1001, VPAP-0817, DNAP-2001 and DNAP-0104, to research industry information to modify the PM procedure for circuit breakers. The inspectors further concluded that the occurrence of a breaker cubicle fire in 2006 as noted above provided sufficient evidence to allow the licensee to foresee and correct an adverse condition regarding age related degradation of main contactors.

Analysis: The inspectors determined that the failure to maintain PM procedures for circuit breakers current with industry information and OE was a PD. This PD had a credible impact on safety due to an original equipment main contactor which was in service for approximately 35 years, and subsequently experienced a coil failure with a consequent fire. The PD was more than minor and therefore a finding because it could be reasonably viewed as a precursor to a significant event based on fire development leading to the loss of other safety-related equipment. In accordance with NRC Inspection Manual Chapter 0609, "Significant Determination Process," the inspectors performed a Phase 1 analysis and determined the finding required a Phase 3 analysis by a regional senior reactor analyst. The significance of this finding is to-be-determined (TDB) pending completion of a phase 3 evaluation. This finding involved the cross-cutting area of corrective action, the component of the OE, and the aspect of implementation and institutionalization of OE through changes to station processes and procedures, P.2(B), because the licensee failed to incorporate existing industry OE to ensure procedural guidance was adequate for testing of the main contactor.

Enforcement: Licensee procedure, DNAP-2001, “Equipment Reliability Process,” Revision 0, effective March, 2003, requires in step 3.4.2, “Preventive Maintenance Program,” that the Preventive Maintenance Program is a living program, with a documented technical basis for each PM. Each PM basis shall be kept current based on operating experience, corrective action reviews, and PM feedback. Contrary to this, on April 22, 2009, the licensee failed to maintain PM procedure, 0-EPM-0304-01, current based on operating experience, corrective action reviews, and PM feedback, to ensure that main contactors for their respective circuit breaker would operate reliably until the next scheduled maintenance. Consequently, a main contactor failure occurred resulting in a breaker cubicle fire. Pending determination of safety significance, this finding is identified as a finding (FIN - TBD) 05000338/2010004-07, Failure to Maintain PM Procedures for Circuit Breakers Current with Industry Information and OE.

.5 Reactor Coolant System Dissimilar Metal Butt Welds (TI 2515/172, Revision 1)

a. Inspection Scope

Based on the schedule of dissimilar metal butt weld (DMBW) examinations under MRP-139, no examinations were required for the current Unit 1 refueling outage (N1R21) and hence none were performed. Additionally, the licensee had not made any changes to the MRP-139 inspection program since the NRC had previously reviewed this program.

b. Observations

In accordance with requirements of TI 2515/172, Revision 1, the inspectors evaluated and answered the following questions:

(1) Implementation of the MRP-139 Baseline Inspections

1. Have the baseline inspections been performed or are they scheduled to be performed in accordance with MRP-139 guidance?

   This portion of the TI was not inspected during the period of this inspection report, but was previously covered in NRC Inspection Report 05000339/2009002.

2. Is the licensee planning to take any deviations from the MRP-139 baseline inspection requirements of MRP-139? If so, what deviations are planned, what is the general basis for the deviation, and was the NEI-03-08 process for filing a deviation followed?

   This portion of the TI was not inspected during the period of this inspection report, but was previously covered in NRC Inspection Report 05000339/2009002.

(2) Volumetric Examinations

This portion of the TI was not inspected during the period of this inspection report, but was previously covered in NRC Inspection Report 05000339/2009002.

(3) Weld Overlays

This portion of the TI was not inspected during the period of this inspection report, but was previously covered in NRC Inspection Report 05000339/2008005.

(4) Mechanical Stress Improvement (SI)

There were no mechanical stress improvement activities performed or planned by this licensee to comply with their MRP-139 commitments.

(5) Application of Weld Cladding and Inlays

There were no weld cladding or inlay activities performed or planned by this licensee to comply with their MRP-139 commitments.

(6) Inservice Inspection Program

1. Has the licensee prepared an MRP-139 inservice inspection program? If not, briefly summarize the licensee's basis for not having a documented program and when the licensee plans to complete preparation of the program.

   No. The licensee did not have a standalone MRP-139 inservice inspection program document. However, the licensee's MRP-139 inservice inspection program was included in their ASME Section XI Inservice Inspection Program (ISI Program) and also attached as augmented inspections to the inservice inspection program. The inspectors reviewed the North Anna Unit 1 Third Interval ISI Plan. The licensee had revised the Third Interval ISI Plan to reflect the examination methods and frequencies for the MRP-139 ISI requirements.

2. In the MRP-139 inservice inspection program, are the welds appropriately categorized in accordance with MRP-139? If any welds are not appropriately categorized, briefly explain the discrepancies.

   Yes. The welds were appropriately categorized by the licensee responsible engineer.

3. In the MRP-139 inservice inspection program, are the inservice inspection frequencies, which may differ between the first and second intervals after the MRP-139 baseline inspection, consistent with the inservice inspections frequencies called for by MRP-139?

   Yes. The licensee plans inspection frequencies for welds in the MRP-139 ISI program to be consistent with the requirements of MRP-139.

4. If any welds are categorized as H or I, briefly explain the licensee's basis of the categorization and the licensee's plans for addressing potential PWSCC.

   The six DMBWs on the pressurizer were classified as category C after the full structural weld overlays were applied. Therefore, no DMBWs are categorized as H or I.

5. If the licensee is planning to take deviations from the MRP - 139 inservice inspection guidelines, what are the deviations and what are the general bases for the deviations? Was the NEI 03-08 process for filing deviations followed?
   The licensee had not planned to take any deviations from MRP-139 requirements.

This completes the TI-2515/172 requirements for North Anna Units 1 and 2.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On October 23, 2010, the senior resident inspector presented the inspection results to Mr. Larry Lane and other members of the staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

On September 24, 2010, the ISI inspectors presented the inspection results to licensee management. The licensee acknowledged the inspection results. The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

W. Anthes, Manager, Nuclear Maintenance
M. Becker, Manager, Nuclear Outage and Planning
M. Crist, Plant Manager
D. Driver, Manager of Electric Transmission
R. Evans, Manager, Radiological Protection and Chemistry
T. Huber, Director, Nuclear Engineering
S. Hughes, Manager, Nuclear Operations
C. Gum, Manager, Nuclear Protection Services
L. Lane, Site Vice President
P. Kemp, Manager, Organizational Effectiveness
J. McHale, Supervisor Electrical Design, North Anna
F. Mladen, Director, Station Safety and Licensing
B. Morrison, Supervisor Nuclear Engineering
C. McClain, Manager, Nuclear Training
R. Scanlan, Manager, Nuclear Site Services
J. Scott, Supervisor, Nuclear Training (operations)
D. Taylor, Supervisor, Station Licensing
E. Walker, Manager of Engineering Programs, Event Review Team Leader

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000338/2010004-01	NCV	Inadequate Procedurally Controlled Temporary Modification for the Emergency Diesel Generator Starting Air System (Section 1R18.1)
05000339/2010004-03	FIN	Failure to Conduct Adequate Review of Calculation Results in Main Turbine/Reactor Trip (Section 4OA3.1.1)
05000339/2010004-04	NCV	Failure to Correctly Translate Turbine Driven Auxiliary Feedwater Pump Lube Oil Subsystem Vent Design Basis into Specifications or Drawings (Section 4OA3.1.2)
05000338, 339/2010004-05	FIN	Inadequate Set Point for Balance-of-Plant Bus Undervoltage Relay (Section 4OA3.3)

05000339/2010004-06	NCV	Failure to Follow Procedure to Trip 'A' Reactor Coolant Pump on High Bearing Temperature (Section 4OA5.3)

<u>Opened</u>

05000338/2010004-02	AV	Failure to Promptly Correct a Condition Adverse to Quality for Valve Actuator Diaphragms (Section 4OA2.2)
05000338/2010004-07	FIN-TBD	Failure to Maintain PM Procedures for Circuit Breakers Current with Industry Information and OE (Section 4OA5.4)

<u>Closed</u>

05000339/2010001-00	LER	Automatic Reactor Trip and ESF Actuation during Automatic Voltage Regulator Testing Due to Inadequate Procedure Guidance (Section 4OA3.1)
05000339/2010003-00	LER	Failure to Isolate Primary Grade Water to Blender Due to Operator Activities (Section 4OA3.2)
05000339/2010002-00	LER	Automatic Reactor Trip and Engineered Safety Feature Actuation Due to Lightning Strike (Section 4OA3.3)
05000339/2010003-03	AV	Failure to Follow Procedure to Trip 'A' Reactor Coolant Pump on High Bearing Temperature (Section 4OA5.3)
05000338/2010002-02	URI	Safety Related Breaker Cubicle Fire Issue (Section 4OA5.4)

<u>Discussed</u>

None

LIST OF DOCUMENTS REVIEWED

Section 1R15: Operability Evaluations
SDBD NAPS-FW, System Design basis Document for Feedwater, Revision 12
CQCA-6, Comprehensive Quality Classification Analysis, Revision 1

Section 1R18: Plant Modifications
NEI 96-07, Revision 1, "Guidelines for 10 CFR 50.59 Implementation"
Safety evaluation for 1, 2-OP-6.7, Revision 10 and 14 respectively
RG 1.187, Guidance for Implementation of 50.59

Section 1R19: Post Maintenance Testing
CR378798, "2-FW-P-2 was secured after auto start due to oil leak"
ACE 018148, "2-FW-P-2 was secured after auto start due to oil leak"
ET-ME93-009, "Steam Driven Aux Feedwater Pump Lube Oil Reservoir Vents"
ET-N-10-0037, "Installation of a vent on 2-FW-TK-2," Revision 1
ET-N-10-0051, "Evaluation of 2-FW-P-2 Lube Oil Reservoir Over-Pressurization," Revision 0
IEER-N-95-5022-000, "Seal, Labyrinth, Aux Feedwater Pumps and Terry Turbines Chesterton Part #363503"
VTM-59-T291-00001, Terry Turbine, Aux Feedwater, Turbine Driven

Section 1EP6: Drill Evaluation
CR388460, PING-3B [EOF area radiation monitor] local beacon did not illuminate.
CR388488, Simulator Master System Task abort occurred near the conclusion of the exercise.
CR388549, CERC Reactor Core Analysis staff observed the simulator display for CH-RM-128 pegged high
CR388578, North Anna and Innsbrook emergency-pager groups Network Computer system failed when activated for EP drill
CR388595, Core Damage modeled in scenario was insufficient to yield off-site dose values
CR388614, Operations did not notify the TSC of dispatching operators into the field
CR388617, Control Room continued to eat and drink during the release
CR388710, Methods used to control Emergency Response Organization (ERO) teams differ in process and rigor when dispatched from the OSC, RP, and Control Room
CR388716, Command and Control - TSC, OSC, and CRS did not remove barriers to support completion of critical response tasks, isolation of 1-MS-18 and closing of 1-MS-SV-101A.
CR388720, during the 7/20/2010 North Anna Biennial Exercise, exercise coordination and conduct weaknesses were identified.
CR388725, During the 7/20/2010 North Anna Biennial Exercise Emergency response facility equipment issues were identified.
CR388789, July 20, 2010, Emergency Preparedness Biennial Exercise, Objection 20, Demonstrate the ability to effectively coordinate and conduct an exercise was not met.
CR388791, A Protective Action Recommendation (PAR) was developed and approved in the Local Emergency Operations Facility that reduced the previous PAR
CR388830, 0-PT-114 was incorrectly signed off as acceptable for the emergency kits
CR388876, Additional guidance needed to assist decision to restore letdown
CR388882, Information provided NRC EP Inspector did not meet expectation
CR388887, During the North Anna evaluated exercise conducted July 20, 2010, objective

number 9, Demonstrate the ability to assess conditions and implement appropriate protective measures for emergency response personnel, including site access control, contamination control, exposure control, use of protective devices and, as appropriate, the process for authorizing the use of potassium iodide (KI), was not adequately demonstrated by the ERO and evaluated as NOT MET.
CR389077, PAR notification timeliness

Section 4OA3: Event Followup

4OA3.1

Calculation EE-0826, "North Anna Unit 2 main Generator Voltage Regulator Settings," Rev 0
RCE0001007, "U2 Trip Due to Digital Automatic Voltage Regulator Software Settings," Rev 2
Nuclear Engineering Standard DNES-AA-GN-1001, Engineering Review," Revision 0
CM-AA-CLC-3001, "Engineering Calculations," Revision 3
AD-AA-102, "Procedure Use and Adherence," Revision 2
CM-AA-101, "Preparation and Processing of Engineering Standards," Revision 2
DNAP-0306, "Software Quality Assurance Program," Revision 2
DCP-07-010, "Main Generator Voltage Regulator Replacements/North Anna/Unit 2"
DCP-07-010, Field Change 1, "Main Generator Voltage Regulatory Replacement/North Anna/Unit 2"
CM-AA-RSK-1001, "Engineering Risk Assessment," Revision 2
CM-AA-DDC-201, "Design Changes," Revision 0
FDTP-07-010-001, "Start-up Testing and Tuning of Main Generator Voltage Regulator," Revision 0
FDTP-07-010-001, "Start-up Testing and Tuning of Main Generator Voltage Regulator," Revision 1
VPAP-0301, "Design Changes Process," Revision 30
CR378800, "Unit 2 Reactor Tripped"

4OA3.3

11715-FE-1BB, One Line Diagram Electrical Distribution System Units 1&2, Rev. 41
11715-ESK-5T, Elementary Diagram – 4160 V Circuits Steam Generator Feedpump Motor 1-FW-P-1A1
11715- FE-4BT, Wiring Diagram Inst Transmitter Rack 1-200 & 1-201
11715-FE-18U, Wiring Diagram 120 V Instrumentation Dist. Pnl's 1A & 1B, Rev. 33
11715-FE-11C, Wiring Diagram 120 VAC Semi-Vital Bus Distribution Panel 1A & 1B, Rev. 29
12050-FE-1B, 4160 V One Line Diagram Bus 2A and Bus 2B, Rev. 11
12050-FE-1C, 4160 V One Line Diagram Bus 2C and Intake Structure Bus 2G, Rev. 16
12050-FE-21G, DC Elementary Diagram 4160 V – Bus 2A, Bkrs 25A1 & 25A2, Bus 2B, Bkrs 25B1 & 25B2, rev. 20
12050-FE-21L, DC Elementary Diagram 4160 V Normal Supply Bus A, B, C Undervoltage Rev. 11
GEI-90806C, Instructions for Undervoltage Relay NGV-15A and NGV-15B, by General Electric Company
Engineering Application Information for NGV Voltage Relays, by General Electric Company
Engineering Application Information for SAM Static Timing Relays, by General Electric Company
NAPS U2 Reactor Trip 05/28/2010 Event Review Team Findings
Instructions for TAPCON 240, by Reinhausen, pages 8, 10 & 21

P-FW102, Feedwater System Main Feed Pump Differential Pressure Alarm and Auto Back-up Pump Motor Start, Rev. 2
DCP No. 08-004, Replacement of Station Service Transformers, Unit 2, Field Change 2, dated 6/1/2010
Work Order 59102140284, Calibrate NGV 15 relays at Bus 2B, completed 5/29/2010
Oil analysis on 230 – 36.5 kV transformer 3, dated 5/28/2010 and 3/9/2010
Motor date sheets and pump performance data for pump 1-FW-P-1A! and 1A2
RCE001012, Low RCS Flow Reactor Trip Resulting from Loss of B Station Service Bus
CR382750, "Unit 2 PG Valve not isolated within required time"
ACE018202, "Unit 2 PG Valve not isolated within required time"
OP-AA-105, "Post Trip Review," Revision 2

<u>4OA3.4</u>
11715-FE-1BB, One Line Diagram Electrical Distribution System Units 1 & 2, Revision 41
11715-ESK-5T, Elementary Diagram – 4160 V Circuits Steam Generator Feedpump Motor 1-FW-P-1A1
11715- FE-4BT, Wiring Diagram Inst Transmitter Rack 1-200 & 1-201
11715-FE-18U, Wiring Diagram 120 V Instrumentation Dist. Pnl's 1A & 1B, Revision 33
11715-FE-11C, Wiring Diagram 120 VAC Semi-Vital Bus Distribution Panel 1A & 1B, Rev 29
12050-FE-1B, 4160 V One Line Diagram Bus 2A and Bus 2B, Revision 11
12050-FE-1C, 4160 V One Line Diagram Bus 2C and Intake Structure Bus 2G, Revision 16
12050-FE-21G, DC Elementary Diagram 4160 V – Bus 2A, Bkrs 25A1 & 25A2, Bus 2B, Bkrs 25B1 & 25B2, Revision 20
12050-FE-21L, DC Elementary Diagram 4160 V Normal Supply Bus A, B, C Undervoltage, Revision 11
GEI-90806C, Instructions for Undervoltage Relay NGV-15A and NGV-15B, by General Electric Company
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Oil analysis on 230 – 36.5 kV transformer 3, dated 5/28/2010 and 3/9/2010
Motor date sheets and pump performance data for pump 1-FW-P-1A! and 1A2
RCE001012, Low RCS Flow Reactor Trip Resulting from Loss of B Station Service Bus, dated

<u>Section 1R08/40A5.5: ISI inspection</u>
<u>Procedures</u>
2-PT-48.6, "Vessel Head Bare Metal Visual Inspection," Revision 1, 9/25/2008
2-PT-48.7, "Vessel Head Volumetric Inspection," Revision 1, 9/25/2008
2-PT-54.1, "Reactor Pressure Vessel Effective Degradation Years Calculation," Revision 1, 4/26/2004
ER-AA-NDE-PT-300, "ASME Section XI Liquid Penetrant Examination Procedure," Revision 4

ER-AA-NDE-PT-301, “Balance of Plant (BOP) Liquid Penetrant Examination Procedure,” Revision 3
ER-AA-NDE-UT-805, “Straight Beam Ultrasonic Examination of Studs and Bolts in Accordance with ASME Section XI, Appendix VIII,” Revision 0
ER-AA-NDE-VT-601, “VT-1 Visual Examination Procedure,” Revision 2
ER-AA-NDE-VT-604, “Visual Examination for Leakage of PWR Reactor Head Penetrations,” Revision 0
ER-AA-NDE-VT-607, “VE Examination of Pressure Retaining Welds in Class 1 Components Fabricated with Alloy 600/82/182 Materials,” Revision 0
ER-AP-BAC-10, “Boric Acid Corrosion Control Program,” Revision 5
ER-AP-BAC-101, “Boric Acid Corrosion Control Program (BACCP) Inspections,” Revision 4
ER-AP-BAC-102, “Boric Acid Corrosion Control Program (BACCP) Evaluations,” Revision 5
ER-AA-MAT-11, “Alloy 600 Management Plan”, Revision 7
ER-NA-AUG-101, “,” Revision 1
MA-AA-1002, “Leakage Management,” Revision 5
MCM-0400-35, “Repacking Manual Valves,” Revision 11
MCM-1006-01, “Repair of Safety-related Piping and Component Bolted Flange Joints,” Rev 19
MCM-1801-01, “Welding Safety-related and Seismic-related Equipment,” Revision 19

Condition Reports
CR394271 1-PT-46.21 leaks identified during boric acid walkdown
CR 325874 Fitting leak with accumulation of boric acid
CR 325876 Brown boric acid on packing of 1-SI-HCV-1851C
CR 325887 Pipe cap leaks on Unit 1 observed during 1-PT-46.21
CR 325946 Boric acid found on components

Other Documents
“Virginia Electric and Power Company (Dominion) North Anna Power Station Unit 1 Inservice Inspection Plan for the Third Inspection Interval,” Revision 10
Certificate of Compliance for Calibration Block 94-6692 (Heat No. A58767A)
Certificate of Contaminant Report for Spotcheck Cleaner/Remover (Batch No. 09L08K), Spotcheck Penetrant (Batch Nos. 05M15K and 06G16K) and Spotcheck Developer (Batch No. 08H01K)
Certified Test Report for Couplant 072-S
ET-N-10-007, North Anna Unit 1 – Fall 2010 Steam Generator Degradation Assessment, Revision 0
Work Order 59102018991 Replace 1-RC-105 dated 9/23/2010
Visual Examination for Boric Acid Detection on Reactor Vessel Upper Head dated 9/18/2010
Welder Performance Qualification Record for Tan, Hoan G. dated 08/15/2002
BACCP Evaluation Form for 1-BR-P-7B, 7B Gas Stripper Circulation Pump dated 8/10/2010
BACCP Evaluation Form for 1-FC-E-1A, Fuel Pit Cooler dated 9/9/2010
BACCP Evaluation Form for 1-SI-P-1B, B LHSI Pump dated 5/13/2010
BACCP Evaluation Form for 1-RP-P-1A/A Refueling Purification Pump dated 08/09/2010
NA-ENGT-000-ET-NAF-09-0044 North Anna Measurement Uncertainty Recapture (MUR)
Upper Head Temperature for Reactor Pressure Vessel Monitoring dated 01/12/2010

LIST OF ACRONYMS

ADAMS	Agencywide Document Access and Management System
CA	Corrective Action
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CR	Condition Report
EDG	Emergency Diesel Generator
ERT	Event Review Team
FIN	Finding
IMC	Inspection Manual Chapter
JPM	Job Performance Measures
LER	Licensee Event Report
LHSI	Low Head Safety Injection
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OD	Operability Determination
PARS	Publicly Available Records
PI	Performance Indicator
QS	Quench Spray
RCE	Root Cause Evaluation
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RSST	Reserve Station Service Transformer
RTP	Rated Thermal Power
SDP	Significance Determination Process
SR	Surveillance Requirements
TDAFWP	Turbine Driven Auxiliary Feedwater Pump
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VEPCO	Virginia Electric and Power Company
VPAP	Virginia Power Administrative Procedure
WO	Work Order