UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

April 28, 2004

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

SUBJECT: SURRY POWER STATION - NRC SUPPLEMENTAL INSPECTION REPORT NO. 05000280/2004009

Dear Mr. Christian:

By letter dated January 23, 2004, you were informed that the United States Nuclear Regulatory Commission (NRC) would conduct a supplemental inspection at your Surry Power Station for a White performance indicator in the initiating events cornerstone. On March 27, 2004, the NRC completed this supplemental inspection. The enclosed report documents the inspection results that were discussed with Mr. Blount and other members of your staff on April 19, 2004.

The purpose of this supplemental inspection was to examine your problem identification, root cause and extent-of-condition evaluation, and corrective actions associated with a White performance indicator in the initiating events cornerstone. The Unplanned Scrams per 7,000 Critical Hours Performance Indicator crossed the threshold from Green to White in the third quarter of calendar year 2003. The inspection examined activities conducted under your license as they relate to safety and compliance with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the NRC determined that the problem identification, root cause and corrective actions for the White performance indicator were adequate. The inspectors did not find common cause aspects linking the four reactor scrams from a risk perspective.

Based on the results of this inspection, no findings of significance were identified. However one licensee-identified violation which was determined to be of very low safety significance is listed in Section 04 of this report. If you contest this non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, DC 20555-0001; 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 Surry 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 NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Docket No.: 50-280
License No.: DPR-32

Enclosure: NRC Inspection Report 05000280/2004009
w/Attachment: Supplemental Information

cc w/encl.:
Chris L. Funderburk, Director
Nuclear Licensing and
Operations Support
Virginia Electric & Power Company
Electronic Mail Distribution

Richard H. Blount, II
Site Vice President
Surry Power Station
Virginia Electric & Power Company
Electronic Mail Distribution

Virginia State Corporation Commission
Division of Energy Regulation
P. O. Box 1197
Richmond, VA 23209

Lillian M. Cuoco, Esq.
Senior Counsel
Dominion Resources Services, Inc.
Electronic Mail Distribution

Attorney General
Supreme Court Building
900 East Main Street
Richmond, VA 23219

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No.:	50-280
License No.:	DPR-32
Report No.:	05000280/2004009
Licensee:	Virginia Electric and Power Company (VEPCO)
Facility:	Surry Power Station, Unit 1
Location:	5850 Hog Island Road Surry, VA 23883
Dates:	February 16 - March 27, 2004
Inspectors:	G. McCoy, Senior Resident Inspector S. Rose, Operations Engineer
Approved by:	K. Landis, Chief, Reactor Projects Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000280/2004009; 02/16/2004 - 03/27/2004; Surry Power Station, Unit 1; Supplemental Inspection IP 95001 for a White performance indicator in the initiating events cornerstone.

This inspection was conducted by the senior resident inspector and an operations engineer. No findings of significance were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process," (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

This supplemental inspection was conducted to assess the licensee's evaluation associated with a White performance indicator in the initiating events cornerstone. The Unplanned Scrams per 7,000 Critical Hours Performance Indicator crossed the threshold from Green to White in the third quarter of calendar year 2003. Specifically, the licensee experienced two reactor trips during the first quarter of 2003, one reactor trip during the second quarter of 2003, and one reactor trip in the third quarter of 2003. The first reactor trip, which occurred on January 14, 2003, was a manual trip from approximately 100 percent reactor power due to high temperature and shaft vibration alarms on the C reactor coolant pump. The second reactor trip, which occurred on January 25, 2003, was an automatic trip from approximately 27 percent reactor power due to problems associated with manually controlling steam generator water level. The third reactor trip, which occurred on June 13, 2003, was a manual trip from less than one percent reactor power due to a control rod misalignment. The fourth reactor trip, which occurred on September 18, 2003, was a manual reactor trip from approximately 79 percent reactor power due to inclement weather conditions and a loss of the 1G and 2G buses which supplied power to all the circulating water pumps for both units.

The licensee's problem identification, root cause and extent-of-condition evaluations, and corrective actions for the four reactor trips were adequate. Common cause aspects linking the four reactor trips from a risk perspective were not evident.

B. <u>Licensee-Identified Violations</u>

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. This violation and corrective action tracking number is listed in Section 05 of this report.

REPORT DETAILS

01 INSPECTION SCOPE

The purpose of this supplemental inspection was to assess the licensee's evaluation associated with a White performance indicator in the initiating events cornerstone of the reactor safety strategic performance area. The Unplanned Scrams per 7,000 Critical Hours Performance Indicator crossed the threshold from Green to White in the third quarter of calendar year 2003. Specifically, the licensee experienced two reactor trips during the first quarter of 2003, one reactor trip during the second quarter of 2003, and one reactor trip in the third quarter of 2003. The first reactor trip, which occurred on January 14, 2003, was a manual trip from approximately 100 percent reactor power due to high temperature and shaft vibration alarms on the C reactor coolant pump. The second reactor trip, which occurred on January 25, 2003, was an automatic trip from approximately 27 percent reactor power due to problems associated with manually controlling steam generator water level. The third reactor trip, which occurred on June 13, 2003, was a manual trip from less than one percent reactor power due to a control rod misalignment. The fourth reactor trip, which occurred on September 18, 2003, was a manual reactor trip from approximately 79 percent reactor power due to inclement weather conditions and a loss of the 1G and 2G buses which supplied power to all the circulating water pumps for both units.

02 EVALUATION OF INSPECTION REQUIREMENTS

02.01 <u>Problem Identification</u>

a. Determination of who identified the issue and under what conditions.

The four reactor trips were self revealing events which occurred during the course of normal operational conditions.

The January 14 trip occurred during normal operations when the operators noted a rapid increase in shaft vibrations and increased lower radial bearing temperatures on the C reactor coolant pump (RCP). These conditions prompted the operators to manually trip the reactor and secure the RCP in accordance with annunciator response procedure 1C-H5, "RCP Shaft Danger."

The January 25 automatic reactor trip occurred during the process of a unit startup. The cause was a low-low level in the B Steam Generator (SG). The challenging man-machine interface issues related to startup feedwater control exceeded the capability of the crew to maintain SG level within its normal band.

The June 13 trip occurred when the operators manually inserted a reactor trip due to a control rod misalignment. When shutdown bank B was being inserted during startup physics testing, the J-7 rod rapidly dropped, resulting in the rod being 53 steps away from the rest of the bank. When it was determined that this was not an indication problem, the reactor was manually tripped and the startup physics testing was terminated.

The September 18 trip occurred during normal operations with adverse weather conditions when the reactor was manually tripped in response to inclement weather conditions and the loss of the 1G and 2G buses which supplied power to all eight circulating water pumps for both units.

b. Determination of how long the issue existed, and prior opportunities for identification.

The January 14 manual trip was prompted by increased shaft vibrations and high temperatures on the C RCP. The RCP motor's lower bearing lost lubrication, overheated and wiped, causing the bearing temperature alarms and vibration alarms. An inspection of the RCP motor after the failure indicated insufficient oil was present in the lower oil reservoir to properly lubricate the lower bearing. The licensee discovered indications of active leakage from several areas around the lower reservoir of the RCP such as the drain pipe flange, the lower oil pan joints, and the level column drain cap. In addition, the licensee identified that the lower oil reservoir level switch for the low level alarm had failed to actuate due to a broken spacer plate bracket. This motor had been overhauled and placed in service during the spring 2000 refueling outage. The oil levels were topped off during the fall 2001 outage, but no investigation was performed for the loss of oil. Thus, a potential opportunity to identify and correct oil leaks was missed. The leakage which lead to this failure occurred after the fall 2001 outage.

The January 25 automatic reactor trip was caused by a low-low level in the B SG. The challenging man-machine interface issues related to startup feedwater control exceeded the capability of the crew to maintain SG level within its normal band. The licensee's root cause evaluation (RCE) determined that the difficulties with manual control of SG water levels at low power and the subsequent reactor trip were due to inadequate modification of the main feedwater regulating valves (FRVs). The FRVs were modified during the fall 2001 refueling outage. The new Control Components Incorporated (CCI) FRVs were more difficult to control than the original Copes Vulcan valves due to a slower response time. Significant differences in response between the old Copes Vulcan and the new CCI valves were not expected. The startup subsequent to the fall 2001 refueling outage provided information on the CCI valves which demonstrated characteristics at low power levels that were unexpected. System engineers were aware of these characteristics and briefed the startup crew; however, the information was never fed back to the simulator group for incorporation into the simulator model. The inspectors concluded that this presented a prior opportunity for identification that a problem existed with the FRVs and the licensee should have had updated characteristics available for the crew to train on in the simulator prior to the subsequent unit startup.

On June 13, during the rod swap portion of control rod testing after a head replacement outage, rod J-7 in rod group 2 experienced a rapid drop from an indicated position of approximately 100 steps to 47 steps on the computer enhanced rod position indication (CERPI) system. The reactor was critical at less than one percent power at the time and the group step counter indicated 96 steps. Licensee investigation found no problems with the CERPI system and the reactor was tripped due to the control rod misalignment. During the trip the control rods were monitored and the J-7 CERPI indication appeared to reach the bottom first. The unit had successfully completed cold rod testing without any unusual responses.

The September 18 trip occurred during normal operations with adverse weather conditions (Hurricane Isabel) when the reactor was manually tripped after a loss of the 1G and 2G buses which supplied power to the low level intake structure (LLIS). The LLIS houses all eight circulating water (CW) pumps for both units. The root cause evaluation determined the cause to be design issues. The power to the LLIS is via two separate non-safety related power lines that run above ground. Prior to 1983 the power lines were routed underground; however, due to problems with cable failures the lines were replaced with overhead cables. The events which lead to the loss of both buses were attributed to the distribution system for the LLIS not being designed to withstand the environmental conditions. Since the LLIS power distribution system and CW pumps are non-safety related equipment, the lines were not constructed with an emphasis on the reliability of electrical service to the LLIS. The existing lines were believed to be capable of withstanding severe weather up to hurricane force winds. Although there were no previous events which resulted in the loss of both power lines, multiple losses of single lines due to environmental conditions had been experienced in the past. The root cause evaluation determined that the shift to overhead lines created potential common cause failures from tree damage and severe weather such as hurricanes and lightning storms. The inspectors concluded that the single line failures represented a prior opportunity to determine that the 1G and 2G buses were a potential single-point vulnerability that could necessitate a manual reactor trip from a single external event.

c. Determination of the plant-specific risk consequences (as applicable) and compliance concerns associated with the issues.

The licensee performed informal risk evaluations which determined that the integrated risk for the events were of very low significance. The inspectors interviewed the risk analyst to confirm the licensee's evaluation and assumptions. One licensee-identified violation is documented in Section 05.

02.02 <u>Root Cause and Extent-of-Condition Evaluation</u>

a. Evaluation of methods used to identify root causes and contributing causes.

The licensee used combinations of different methods, e. g., interviews, timelines, the "Why" staircase, and barrier analysis, to identify root and contributing causes for the four reactor trips. The methods and combinations of methods used to identify root and contributing causes for the four reactor trips were appropriate.

For the January 14 trip evaluation, the licensee utilized interviews, as well as, cause and effect analysis, causal factor analysis and barrier analysis to evaluate the root causes and contributing causes.

For the January 25 trip evaluation, the licensee utilized interviews in conjunction with the "Why" staircase analysis to arrive at the root causes and contributing causes.

For the June 13 trip evaluation, the licensee utilized interviews to arrive at the root and contributing causes. Since the trip occurred during reactor plant testing and the failure did not affect the safety-related functions of the control rod drive mechanism (CRDM) a detailed root cause evaluation was not performed.

For the September 19 trip evaluation, the licensee utilized interviews, barrier analysis, the "Why" staircase, and a comparative timeline. The licensee also solicited information from other utilities and vendors to determine the root cause.

b. Level of detail of the root cause evaluation.

For the four reactor trips, the root cause evaluations were of sufficient detail to support the identified root and contributing causes.

For the January 14 trip, the licensee identified three root causes and six contributing causes. The root causes were attributed to inadequate monitoring of the vendor's workmanship during the overhaul of the motor in May 2000, inadequate work practices by licensee maintenance personnel, and inadequate vertical information flow to decision makers. The first two failures caused the oil leaks which resulted in the lubrication failure in the lower bearing. The third failure focused on the decision to remove the strongbacks from the lower oil pan. Historically, the lower oil pan had been a source of leakage for this model of RCP. The licensee had opted in favor of adding additional bolts to seal the joints to reduce this leakage, but this modification was not effective without the addition of the complementary strongbacks to strengthen the oil pan walls. The decision not to install the strongbacks was not properly reviewed, approved, or documented in the licensee's modification documentation. The contributing causes addressed the failure of the lower oil reservoir level switch, the improper installation of the lower radial bearing resistance temperature detector (RTD), and the failure to monitor oil usage in the RCPs. These were additional failures, though not contributing directly to the loss of oil, which prevented other methods of early detection. The level of detail of the root cause evaluation for this trip was adequate to support the root causes and the contributing causes.

For the January 25 trip, the licensee identified two root causes and four contributing causes for the automatic trip which resulted from the low-low level in the B SG. The first root cause was attributed to managerial methods. The need for improved feedwater flow and steam flow control for low power operation had never been implemented although both were recommended in 1984 and again in 1996. The second root cause was due to design configuration and analysis. The FRV modification implemented during the fall 2001 refueling outage was a scope change from the original plan to evaluate automatic low power steam generator level control. The new CCI FRVs were more difficult to control than the original Copes Vulcan valves due to a slower response time and differing flow characteristics as the valves are opened. The licensee determined the design to be inadequate due to not appropriately incorporating the differing valve operating characteristics into the modification. The first contributing cause was the man-machine interface design, i.e., the lack of accurate steam flow and feedwater flow indications at low power levels. The second contributing cause was training and qualification due to inadequate simulator fidelity. The simulator system response was not representative of actual plant startups/shutdowns at low power levels with respect to FRV operation. The third contributing cause was plant/system operation, in that, the effect of changing operating parameters was not properly evaluated. As a consequence, no consistent startup methodology between the different operating teams was established. The fourth contributing cause was the interface design, in that, additional controls and display were needed. Feedwater bypass flow and total feedwater flow indication did not exist at low power levels. The level of detail of the root cause evaluation for the January 25 trip was adequate to support the root and contributing causes but was limited in the fact that it did not determine why the details of the original design change of the Copes Vulcan FRV to the CCI FRV did not get incorporated into the simulator for proper training. The inspectors determined that the simulator support group did the best they could with the information that was provided and the design engineers should have provided more information.

For the June 13 trip, the licensee determined that the most likely cause of the connector failure was that pin D of the electrical connector for the movable gripper coil of control rod J-7 was disturbed by workers during evolutions associated with the CRDM removal as part of the reactor vessel head replacement project. The pin was partially recessed into the connector and did not make good electrical connection with the other side of the connector. The poor electrical connection and differential movement inside the connector during plant heatup resulted in an intermittent loss of continuity during rod testing. This intermittent loss caused the gripper coil to loose power for a short period of time, allowing the rod to fall 53 steps into the core before the coil re-energized. During the repair, the licensee re-seated the pin into the electrical connector and the cable was reconnected. The failure of the rubber retainer which holds the pin was ruled out as a cause because, during the repair, the pin positively seated into its detent without any excess tolerance. The level of detail of the cause evaluation for this trip was adequate to support the apparent cause.

For the September 19 trip, the licensee determined that the root cause of the loss of the 1G and 2G buses was due to inadequate system design. The root cause evaluation determined that the LLIS electrical distribution system was designed with insufficient emphasis on system reliability and was not designed for the environmental conditions experienced. The contributing cause for this event was that the LLIS electrical distribution system was not perceived as vulnerable to severe weather. The inspectors determined that the evaluation of this root cause analysis was sufficiently detailed to support the root and contributing causes.

c. Consideration of prior occurrences of the problem and knowledge of prior operating experience.

The inspectors determined that root cause evaluations for the four reactor trips properly considered prior occurrences of similar problems where applicable.

d. Consideration of potential common causes and extent of condition of the problem.

The licensee has performed a common cause evaluation to identify common contributing factors in 19 different events which resulted in formal root cause evaluations. This effort used a bubble chart to compare and contrast the root causes and contributing causes from each evaluation. The team recommended the implementation of improved equipment reliability programs to enhance plant performance. This included the establishment of a station equipment reliability team to better distribute licensee resources to improve equipment performance. The team also recommended the performance of a single point vulnerability study which will utilize the site's operating experience and examine details and circumstances in an effort to prevent future reactor trips from single point failures. The inspectors noted that the common cause covered several additional events beyond the four trips in question. The inspectors reviewed the licensee's common cause evaluation and determined that it was adequate.

02.03 Corrective Actions

a. Appropriateness of corrective actions.

The licensee took prompt corrective actions to repair the equipment failures related to the reactor trips. Comprehensive corrective actions to address root and contributing causes, where appropriate, were performed or scheduled to be performed.

To address the cause of the January 14 trip, the licensee disassembled, inspected and replaced the damaged RCP radial bearing. The lower radial bearing RTD was also replaced. The various oil leaks from the lower oil reservoir were corrected. Strongbacks were installed on the oil pan to eliminate further leakage. After the RCP was returned to service, the lower reservoir was inspected for leaks, and none were identified. Other actions addressing the contributing causes included:

- Physical and procedural modifications to improve the reliability of the oil reservoir level switches,
- Modifications to the design of the RCP lower radial bearing RTD to provide easier installation and more accurate indication, and
- Enhancements to procedures to monitor the amount of oil added to the RCPs to make up for oil losses during operation.

The inspectors determined that the licensee's corrective actions were appropriate and adequate to prevent recurrence of this failure.

To address the January 25 trip, the licensee's immediate corrective action was to provide additional training to the startup crew. In addition, the training simulator was modified to replicate the response characteristics of the new style CCI FRVs and the operating crew responsible for the re-start of the unit received start-up simulator training. The long term corrective actions to prevent recurrence were additional modifications to the FRVs during the next scheduled refueling outage in spring of 2003. The additional modifications to the feedwater system were effective in providing the reactor operators bypass flow indication and refined feedwater flow control. Startup training was provided prior to using the new systems and methodology. The licensee's investigation notes that the simulator exactly replicates the plant during startup operation of the FRVs. The licensee's design engineering department performed a self assessment to evaluate the modification process to prevent recurrence and is currently performing the corrective actions from the assessment. The inspectors determined that the licensee's corrective actions were appropriate and adequate to prevent recurrence of this failure.

To address the June 13 trip, the licensee repaired and successfully retested the CRDM connector. Long term corrective actions included the modification of plant procedures to explicitly require the inspection of CRDM connectors during connection of the CRDM wires to the reactor vessel head. The licensee also committed to the inspection of the moveable, lift and stationary coil connectors for all the CRDMs on Unit 1 and Unit 2. The Unit 2 inspections were completed as part of the head replacement project in the fall of 2003. The inspectors determined that the licensee's corrective actions were appropriate and adequate to prevent recurrence of this failure.

To address the September 19 trip, the licensee restored power to the LLIS through the above ground power lines as an immediate corrective action. As corrective action to prevent recurrence, the licensee will install underground power lines from the switchyard to the LLIS. The LLIS power distribution system will have the capability to switch from the above ground distribution line to the under ground distribution line to create a redundant power path in order to improve reliability and eliminate this single-point vulnerability. The inspectors determined that the licensee's corrective actions and planned actions were appropriate and adequate to prevent recurrence of this failure.

b. Prioritization of corrective actions.

The inspectors determined that the corrective actions for the four reactor trips were properly prioritized.

c. Establishment of a schedule for implementing and completing the corrective actions

The inspectors verified that the licensee's corrective action program identified assigned individuals, completion dates, and reference numbers to ensure that individual corrective actions would be completed in accordance with their priority.

d. Establishment of quantitative or qualitative measures of success for determining the effectiveness of the corrective actions to prevent recurrence

The inspectors determined that effectiveness reviews had been scheduled for all four trips. They will be performed after the completion of all the applicable corrective actions.

03 OTHER ACTIVITIES

a. <u>(Closed) Licensee Event Report (LER) 05000280/2003001-00</u>, Manual Reactor Trip Due to Degraded Conditions on C Reactor Coolant Pump.

The inspectors reviewed the LER and associated plant issue and no new findings were identified. A summary of this issue is included in Section 02 of this report. This event and the resulting corrective actions are documented in the licensee's corrective action program as Plant Issue S-2003-0134.

b. (Closed) LER 05000280/2003002-01, Manual Steam Generator Level Control Results in Power Ascension Reactor Trip.

The inspectors reviewed this LER and the associated plant issue. As identified in the description in Section 02 of this report, the licensee failed to appropriately incorporate the new FRV operating characteristics into the modification. This finding is more than minor because it is associated with the initiating events cornerstone and directly affects the design control attribute. Since this finding does not contribute to the likelihood of a primary or secondary system loss of cooling accident, does not affect the likelihood that mitigation equipment will be available, or increase the likelihood of a fire or flood, it is determined to be of very low safety significance (green). This licensee-identified finding is a violation of 10 CFR 50 Appendix B, Criterion III "Design Control." Enforcement aspects of this violation are addressed in Section 05 of this report. This event and the resulting corrective actions are documented in the licensee's corrective action program as Plant Issue S-2003-0331.

c. (Closed) LER 05000280/2003003-00, Control Rod Electrical Connector Pin Defect Results in Manual Reactor Trip.

The inspectors reviewed the LER and associated plant issue and no new findings were identified. The results of this review is discussed in section 02 of this report. The event and resulting corrective actions are documented in the licensee's corrective action program as Plant Issue S-2003-2869.

04 MANAGEMENT MEETINGS

Exit Meeting Summary

On April 19,2004, the resident inspectors presented the inspection results to Mr. Blount and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

05 LICENSEE-IDENTIFIED VIOLATION

The following violation of very low safety significance (green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section IV of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a Non-Cited violation.

- 10 CFR 50 Appendix B Section III requires that design control measures shall provide for verifying or checking the adequacy of design and that design changes shall be subject to control measures commensurate with those applied to the original design. Contrary to the above, the licensee failed to verify the adequacy of design, in that, the operating characteristics of the new feedwater regulating valves were not appropriately addressed in a modification package. This finding was of very low safety significance as discussed in Section 03.b. This issue is addressed in the licensee's corrective action program as Plant Issue S-2003-0331.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

R. Allen, Manager, Outage and Planning
R. Blount, Site Vice President
M. Gaffney, Director, Nuclear Station Safety and Licensing
B. Garber, Supervisor, Licensing
T. Huber, Manager, Engineering
L. Jones, Manager, Radiation Protection and Chemistry
D. Llewellyn, Manager, Training
R. MacManus, Manager, Nuclear Oversight
K. Sloane, Director, Nuclear Station Operations and Maintenance
B. Stanley, Manager, Maintenance
J. Swientoniewski, Manager, Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Closed

05000280/2003001-00	LER	Manual Reactor Trip Due to Degraded Conditions on C Reactor Coolant Pump (Section 03.a)
05000280/2003002-01	LER	Manual Steam Generator Level Control Results in Power Ascension Reactor Trip (Section 03.b)
05000280/2003003-00	LER	Control Rod Electrical Connector Pin Defect Results in Manual Reactor Trip (Section 03.c)

Discussed

None

LIST OF DOCUMENTS REVIEWED

January 14, 2003 Reactor Trip

LER 05000280/2003001-00
Root Cause Evaluation - S-2003-0134

Annunciator Response Procedure 1C-H5, “RCP Shaft Danger”

<u>January 25, 2003 Reactor Trip</u>

LER 05000280/2003002-00, 01
Root Cause Evaluation - S-2003-0331
DCP 99-029, Feedwater Regulating Valve Modification
Procedure 1-E-0, Reactor Trip or Safety Injection

<u>June 13, 20003 Reactor Trip</u>

LER 05000280/2003003-00
Root Cause Evaluation - S-2003-2869
Plant Issue S-2003-2876
Plant Issue S-2003-2982

<u>September 19 Reactor Trip</u>

LER 05000280/2003004-00, 01
Root Cause Evaluation - S-2003-4165
Procedure 1-E-0, Reactor Trip or Safety Injection
Procedure 0-AP-12.01, Loss of Intake Canal Level
Procedure 0-AP-37.01, Abnormal Environmental Conditions

<u>Other Documents</u>

Common Cause Evaluation - S-2003-0798
Common Cause Evaluation - Surry Units 1 and 2 NRC ROP Performance of January 19-23, 2004