July 29, 2004

EA-04-110

Mr. George Vanderheyden
Vice President - Calvert Cliffs Nuclear Power Plant
Constellation Generation Group, LLC
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657-4702

SUBJECT: NRC SPECIAL INSPECTION (SI) TEAM REPORT NO. 05000317/2004008 AND 05000318/2004008, AND PRELIMINARY WHITE FINDING - CALVERT CLIFFS NUCLEAR GENERATING STATION

Dear Mr. Vanderheyden:

On May 14, 2004, the US Nuclear Regulatory Commission (NRC) completed a Special Inspection at the Calvert Cliffs Nuclear Power Plant, Units 1 and 2. The enclosed report documents the inspection findings which were discussed with you and other members of your staff during an exit meeting on June 18, 2004.

This inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed selected procedures and records, observed activities, and interviewed personnel. In particular, the inspection reviewed event evaluations (including technical analyses), root cause investigations, relevant performance history, and extent of condition to assess the significance and potential consequences of issues related to both reactor trips on January 23, 2004, (Unit 2) and March 20, 2004, (Unit 1).

The team concluded that the overall response of Constellation to the reactor trips on January 23, 2004, and March 20, 2004, were adequate, in that the plants were taken to a safe shutdown condition. Nevertheless, the operators were challenged by equipment problems and implementation of emergency operating procedures. Several of these issues were the result of human performance issues. During the Unit 2 event, some operator actions, executing emergency operating procedure 0, "Post-trip Immediate Actions," were delayed due to past operating practices.

This report documents one finding that appears to have low to moderate safety significance. As described in Section 2.1 of this report, this finding involved a reactor regulating system (RRS) relay that was not designed for the voltage conditions to which it was exposed and had been in-place since the original construction of the facility. In addition, when Calvert Cliffs implemented a modification to the turbine bypass valve and atmospheric dump valve control system in 1992, they missed an opportunity to identify the inappropriate design. This condition resulted in the relay failure in the RRS that prevented the system from properly regulating the reactor coolant temperature after the Unit 2 reactor trip on January 23, 2004. This resulted in a safety injection actuation signal and steam generator isolation.

This finding was assessed using the reactor safety Significance Determination Process (SDP) as a potentially safety significant finding that was preliminarily determined to be White for Unit 2 (i.e., a finding with some increased importance to safety, which may require additional NRC inspection). The finding appears to have low to moderate safety significance because the likelihood of core damage increased due to the loss of normal decay heat removal and loss of low pressure feedwater supply. Based on analysis of the failed relay, the RRS condition would have resulted in a similar uncontrolled cooldown, following a reactor trip any time during the previous eight months.

We believe that we have sufficient information to make our final risk determination for the performance issue regarding the RRS relay failure. However, before the NRC makes a final decision on this matter, we are providing you an opportunity to either submit a written response or to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding and the bases for your position. If you choose to request a Regulatory Conference, we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference.

Please contact Mr. Richard Conte at (610) 337-5183 within 10 business days of the date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision and you will be advised by separate correspondence of the results of our deliberations on this matter.

Additionally, based on the results of this inspection, the team identified seven findings of very low safety significance (Green). Five of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance, and because they have been entered into your corrective action program, the NRC is treating these issues as non-cited violations, in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. If you deny the non-cited violations noted in this report, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Calvert Cliffs facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosures 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).

If you have any questions, please contact Mr. Conte at (610) 337-5183.

Sincerely,

/R.V. Crlenjak for:

Wayne D. Lanning, Director
Division of Reactor Safety

Docket Nos: 50-317, 50-318
License Nos: DPR-53, DPR-69

Enclosure: Inspection Report 05000317/2004008 and 05000318/2004008
w/Attachments: Supplemental Information

Attachments:
A. Supplemental Information
B. Special Inspection Team Charter
C. Unit 2 Sequence of Events

cc w/encl:
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President, Calvert County Board of Commissioners
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-317, 50-318
License Nos:	DPR-53, DPR-69
Report Nos:	05000317/2004008 and 05000318/2004008
Licensee:	Constellation Generation Group, LLC
Facility:	Calvert Cliffs Nuclear Power Plant, Unit 1 and Unit 2
Location:	1650 Calvert Cliffs Parkway Lusby, MD 20657-4702
Dates:	February 16, 2004 - May 14, 2004
Inspectors:	A. Blamey, Team Leader S. Barr, Senior Operations Engineer G. Cobey, Senior Risk Analyst M. Giles, Senior Resident Inspector A. Passerelli, Reactor Engineer J. Richmond, Resident Inspector W. Schmidt, Senior Risk Analyst H. Williams, Operations Engineer
Approved by:	Wayne D. Lanning, Director Division of Reactor Safety

Enclosure

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SUMMARY OF FINDINGS

IR 05000317/2004-008, 05000318/2004-008; 02/16/04-02/20/04, 03/22/04-03/23/04, 05/10/04-05/14/04; Calvert Cliffs Nuclear Power Plant, Units 1 and 2; Special Inspection Team.

The inspection was conducted by four regional inspectors, two resident inspectors, and two regional senior reactor analysts. One finding, assessed as Preliminary White on Unit 2, and seven other Green findings 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. NRC Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- **Preliminary White.** A self-revealing event identified a finding of low to moderate safety significance, because Calvert Cliffs Nuclear Power Plant (CCNPP) did not perform a modification design review, as required by station procedures. Following a Unit 2 reactor trip on January 23, 2004, the atmospheric dump valves and turbine bypass valves automatically Quick Opened, as designed. However, the Quick Open signal did not clear when the reactor coolant temperature dropped below the Quick Open setpoint, because of a reactor regulating system relay failure. As a result, an uncontrolled cooldown of the reactor coolant system occurred, which in turn caused a loss of the normal heat removal system.

  This finding was more than minor because it was considered to be a precursor to a more significant event. A Significance Determination Process Phase-3 risk analysis determined that this finding was of low to moderate safety significance, based on the change in core damage frequency. (Section 2.1.b.1)

- **Green.** A self-revealing event identified a non-cited violation of very low safety significance of Technical Specification 5.4.1, because CCNPP did not adequately implement modification work instructions. As a result, during a plant event, recovery actions were delayed because operators were unable to reset the "B" channel of the safety injection actuation signal (SIAS) system from the control room.

  This finding was more than minor because the SIAS system was returned to service, following modification work, and subsequently became unable to perform its function, similar to example 5.b in NRC Inspection Manual 0612 Appendix E. This finding had very low safety significance because the finding did not represent an actual loss of a safety function.

  A contributing cause of this finding was related to the Human Performance cross-cutting area because maintenance technicians did not adequately implement written work instructions. (Section 2.2.b.1)

- **Green.** The inspectors identified a non-cited violation of very low safety significance of 10 CFR 50 Appendix B, Criterion XVII, "Quality Assurance Records," because CCNPP did not retain records of test results. From 1999 to March 2004, CCNPP did not retain wiring verification point-to-point test records for modifications of safety-related circuits. As a result, after the records are transferred to Records Management, verification of the work performed cannot be done.

  This finding was more than minor because the failure to retain the required records was not an isolated example, and the records were irretrievably lost, similar to example 1.b in NRC Inspection Manual 0612 Appendix E. This finding was not suitable for a Significance Determination Process evaluation, but was reviewed by NRC management and determined to be of very low safety significance.

  A contributing cause of this finding was related to the Human Performance cross-cutting area because station personnel did not adequately implement written instructions in a safety-related procedure. (Section 2.3)

- **Green.** A self-revealing finding of very low safety significance was identified because CCNPP failed to perform an adequate design review which resulted in reduced reliability of the digital feedwater system during a plant event on March 20, 2004.

  This finding was more than minor because it effected the design control attributes of the Initiating Events cornerstone. Incorrectly specifying the design voltage resulted in reduced reliability of the digital feedwater control system which increased the likelihood of an event that upset plant stability during power operation. This finding was of very low safety significance, because one of two turbine driven feedwater pumps and one of three condensate and condensate booster pumps remained operable during the Unit 1 March 20, 2004, event. (Section 2.4)

- **Green.** The inspectors identified a non-cited violation of CCNPP Technical Specification 5.4.1.b because the operating crew did not properly implement station emergency operating procedures during the Unit 2 reactor trip reactor shutdown on January 23, 2004.

  The finding was more than minor because it affected the Initiating Events Cornerstone in that the failures to follow station procedures complicated the plant's post-trip response and the ability of the operators to restore normal plant conditions. This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event.

  A contributing cause of the finding was related to the Human Performance cross-cutting area because licensed operators did not properly implement station emergency operating procedures. (Section 3.1)

- **Green.** The inspectors identified a non-cited violation of CCNPP Technical Specification 5.4.1.a because CCNPP did not have a procedure (off-normal) for the failure of the reactor regulating system (RRS) as required by Regulatory Guide 1.33.

This finding was more than minor because if the operators had switched to the alternate channel of RRS, after the failure of the RRS relay in the X channel, the atmospheric dump valves (ADVs) and turbine bypass valves (TBVs) would have properly controlled reactor temperature and terminated the uncontrolled cooldown. This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event. (Section 3.2)

- **Green.** A self-revealing event identified a finding in that CCNPP did not follow procedural requirements in their risk assessment and control of the work on March 20, 2004, which resulted in an unanticipated reactor trip. Specifically, the provisions and controls of procedures NO-1-100, “Conduct of Operations,” NO-1-117, “Integrated Risk Management,” and MN-1-100, “Conduct of Maintenance,” were not followed.

  This finding was more than minor because the failures to follow station procedures affected the Initiating Events cornerstone in that the failure to properly risk-classify and control the work in the control room on March 20 lead to the reactor trip. This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event.

  A contributing cause of the finding was related to the Human Performance cross-cutting area because CCNPP managers and staff did not properly implement station operations, risk management, and maintenance procedures. (Section 3.4)

- **Green.** The inspectors identified a non-cited violation of 10CFR50.54(q) because the operating crew did not properly recognize plant conditions commensurate with an Unusual Event in accordance with the emergency plan and implementing procedures during the Unit 2 reactor trip on January 23, 2004.

  This finding was more than minor because it effected the response organization performance attribute of the Emergency Preparedness Cornerstone in that failure to properly recognize plant conditions commensurate with an Unusual Event classification. This finding was of very low safety significance, because it involved an implementation problem during an actual event and the CCNPP staff failed to identify the Unusual Event in the post trip review.

  This finding is related to the Human Performance cross-cutting area because the operating crew did not properly recognize plant conditions commensurate with an Unusual Event in accordance with the emergency plan during a Unit 2 excessive steam demand event on January 23, 2004. (Section 4.1)

Report Details

1.0 Description of Events

1.1 Event Summaries

January 23, 2004, Excessive Steam Demand Event (Unit 2)

On January 23, 2004, Calvert Cliffs Unit 2 was operating at 100% power. At 3:26 p.m., the 22 steam generator feed pump (SGFP) unexpectedly tripped off. Operators attempted to reset and restart the 22 SGFP three times but were unable to reset the pump trip. Without this pump operators were unable to maintain water level in the steam generators, and they monitored water level approaching the trip criteria. Just prior to the operators initiating a manual reactor trip, the automatic trip set point was reached, and the unit experienced a reactor trip at 3:27 p.m. The operators entered emergency operating procedure (EOP) - 0, Post-Trip Immediate Actions. When the reactor tripped, the reactor regulating system controlled the removal of stored energy in the reactor coolant system (RCS) and the secondary system with the quick-open signal which opened the turbine bypass valves (TBVs) and atmospheric dump valves (ADVs). The quick open signal is designed to have the TBVs and ADVs initially fully open, then modulate, to automatically control RCS temperature at 532 degrees Fahrenheit. In this event however, the TBVs and ADVs remained full open, causing a rapid overcooling and depressurization of the RCS.

Due to lowering steam generator water levels, an Auxiliary Feedwater Actuation Signal (AFAS) occurred at 3:28 p.m., and the 21 and 23 Auxiliary Feedwater (AFW) pumps started and provided water to the steam generators as designed. At 3:28 p.m. RCS pressure decreased to 1740 psia, causing a Safety Injection Actuation Signal (SIAS). Equipment which started as a result of the SIAS included the 2A and 2B emergency diesel generators (EDGs), the high pressure safety injection pumps, the containment spray pumps and the low pressure safety injection pumps. RCS pressure remained high enough that the charging pumps were the only source of injection into the RCS. The SIAS signal also stopped RCS letdown and de-energized the back-up pressurizer heaters. The operators stopped two reactor coolant pumps (RCPs) per the procedure requirements following receipt of a SIAS signal.

At 3:28 p.m., a Steam Generator Isolation Signal (SGIS) was received when steam generator pressure decreased below the setpoint, causing the main steam isolation valves (MSIVs) to shut. This isolated steam flow through the TBVs. At approximately nine minutes after the reactor trip, the operators transferred control of the ADVs to the Auxiliary Shutdown Panel to remove the "quick open" signal which was still present to the ADVs. Once ADV control was transferred to the Auxiliary Shutdown Panel, the ADVs closed and the cause of the overcooling and depressurization event was terminated. RCS pressure was 1523 psia and the RCS temperature was 486 degrees Fahrenheit. Pressurizer level was below the bottom of the indicating range.

Due to post-trip reactor decay heat, the plant parameters began to restore to normal post-trip values. At 3:39 p.m., pressurizer level instrumentation began to indicate a level increase as expected.

At 3:55 p.m. the operators transitioned to EOP-1, Reactor Trip. With a SIAS signal still present, all charging pumps were running and RCS letdown was isolated. The operators took manual control of pressurizer main spray to control rising RCS pressure. RCS pressure was stabilized at 2318 psia at approximately 3:56 p.m. At 4:01 p.m., the operators removed 22 and 23 charging pumps from service because pressurizer level was still increasing (264-inches). At 4:06 p.m., 21 charging pump was stopped. All injection had been stopped at this point. At 4:08 p.m., the operators stopped the RCS heat-up at 515 degrees Fahrenheit by modulating the ADVs, and RCS pressure began to decrease uncontrollably.

The operators attempted to reset the SIAS signal to allow restoration of plant systems. Of specific interest to the crew were the back-up pressurizer heaters needed to raise RCS pressure to normal value and the RCS letdown control valves needed to lower pressurizer level to the normal operating band. At 4:17 p.m., SIAS channel "A" was reset from the control room. SIAS channel "B" would not reset from the control room. The operators were able to reset the SIAS "B" signal at the Engineered Safety Features Actuation System (ESFAS) cabinet located in the cable spreading room at 4:27 p.m.

At 4:45 p.m., RCS pressure was at 1782 psia, and the operators began heating the RCS to return parameters to within the normal post-trip temperature band of 525-535 degrees Fahrenheit. Back-up pressurizer heaters, RCS letdown, and 21 charging pump were returned to service. Due to the large volume of subcooled water that had been added to the pressurizer, RCS pressure continued to slowly decrease despite having all pressurizer heaters in service. At 5:18 p.m., a second SIAS actuation was received at approximately 1750 psia. At this point, RCS pressure stabilized at approximately 1745 psia for the next 30 minutes. To restore pressurizer heater capacity the operators blocked and reset SIAS, and pressurizer pressure began to recover to its expected value.

March 20, 2004, No. 11 Steam Generator Low Level Event (Unit 1)

During the Unit 2 refueling outage in April 2003, CCNPP identified a design deficiency related to varistors installed in the feedwater regulating valve and feedwater regulating bypass valve digital feedwater indicators. The same deficiency existed on Unit 1, in that if a ground occurred on the 1Y09 or 1Y10 bus the potential existed to lose all AC power to the Unit 1 digital feedwater control system. CCNPP planned for the removal of these varistors and considered different compensatory measures to be used until that replacement. Operations management did not want to use an interim fix based on the risk involved in their implementation and decided the varistor vulnerability could be controlled by limiting the work done on the 1Y09 and 1Y10 buses. Calvert Cliffs records indicated that the initial work control strategy was effective in that work was prevented on the buses through approximately August 2003; however, soon thereafter work on the

1Y09 and 1Y10 buses again became routine with no additional controls placed on the work.

On March 20, 2004, maintenance technicians performed work on 1-ER-101, a 500KV chart recorder in the control room. As part of that work, at 1:19 p.m., maintenance technicians were installing the recorder into panel 1C29. As the recorder was being installed, a power lead to the recorder became pinched between the recorder and its case, and shorted to ground. This resulted in a large bang in the control room, as well as a ground on 1Y09.

The technicians notified the control room operators of this issue, and the operators reviewed their indications and controls for the operating units, and noted no immediate concerns. The only noted abnormality at that time was that the 12 steam generator digital feedwater back-up central processing unit had re-booted. Later review of saved data also showed that the feedwater regulating valve controller had also re-booted.

Unknown to the operators, due to the ground on bus 1Y09 phase C, a potential of 208 volts existed from line to ground on phases A and B of 1Y09 and their associated components. Due to the known design issue with the Dixson digital feedwater indicators, this potential caused the Dixsons to attempt to reduce the voltage back to 120VAC through the varistors. The varistors tried to limit the voltage for approximately 19 minutes. At 1:39 p.m., due to the ground that still existed on 1Y09, the varistors failed, causing a line to neutral fault. This caused the fuses in the digital feedwater controls to open for the 1Y09 power feed. During this time period, the operators noticed the flashing of digital feedwater components. The digital feedwater electrical power feeds are designed to be protected by the use of an automatic bus transfer (ABT) switch which shifts the input power source from 1Y09 (primary) to 1Y10 (backup) if a fault appears on 1Y09. The ABT shifted from 1Y09 supply to the 1Y10 supply, but due to the short existing down stream via the varistors, the fuses for the 1Y10 feed to the digital feedwater controls also opened.

This resulted in the loss of the 11 digital feedwater ABT bus, which in turn resulted in the deenergization of the 11 main and 12 backup CPUs for digital feedwater. The 11 FRV positioner selector solenoid, 1-SV-1111B failed to electrically shift to the A position, because of mechanical binding in the solenoid valve. This resulted in a loss of signal to the 11 FRV, which immediately began closing. Steam generator water levels dropped quickly, resulting in a reactor trip at 1:40 p.m. Approximately eight seconds prior to the trip, the operators had shifted 12 FRV to manual. Additionally during the last 15 seconds of the event, 11 SGFP tripped on high discharge pressure as a result of the 11 FRV closure.

Immediately after the trip the TBVs opened as a result of the quick open signal. They shut when the quick open signal was clear but did not reopen to modulate TBV flow and control RCS temperature. The operators placed the TBV controller in manual, but the valves still remained closed. Since the TBVs were not operating, the ADV controller was placed in manual and modulated to control the cool down. During the same time, 12 steam generator feed pump was still reacting to the loss of 11 steam generator feed pump, increasing in speed and discharge flow. At approximately 20 seconds post trip, 12 FRV shut due to high 12 steam generator water levels, and 12 steam generator feed pump tripped on high discharge pressure. When steam generator water levels decreased to the AFAS setpoint, the system actuated and re-initiated feed to the steam generators.

2.0 Equipment Failures and Root Causes

2.1 Unit 2 Reactor Regulating System Quick Open Circuit

a. Inspection Scope

Following a Unit 2 reactor trip on January 23, 2004, the reactor regulating system (RRS) Quick Open signal did not clear when the reactor coolant temperature dropped below the setpoint. As a result, an uncontrolled cooldown of the reactor coolant system occurred.

The inspectors reviewed the design of the RRS, ADVs, and TBVs, and interviewed plant personnel to independently determine what occurred and evaluate the initiating causal factors. The inspectors also reviewed the material history and maintenance activities associated with the RRS system. The inspectors assessed CCNPP's root cause analysis and corrective actions to evaluate the adequacy of CCNPP's conclusions and actions.

b. Findings

One self-revealing preliminary white finding and two inspector observations are documented in this section. The observations were minor issues that were related to the human performance cross-cutting area.

1. Failure to Adequately Implement a Modification Design Review of the Reactor Regulating System Quick Open Circuit

Introduction. A self-revealing event identified a Preliminary White finding because CCNPP did not perform a modification design review, as required by station procedures. A preliminary risk analysis determined the finding to be of low to moderate safety significance, because the likelihood of core damage had increased due to an RRS relay failure. Following a reactor trip on January 23, 2004, the ADVs and TBVs automatically Quick Opened, as designed. However, the Quick Open signal did not clear when the reactor coolant temperature dropped below the Quick Open setpoint, because of the RRS relay failure. As a result, an uncontrolled cooldown of the reactor coolant system occurred, which in turn caused a loss of the normal heat removal system.

Description. Following a reactor trip, the ADVs and TBVs automatically Quick Opened, as designed. However, the Quick Open signal did not clear when the reactor coolant temperature dropped below the setpoint of 557 degrees T-Avg. As a result, an uncontrolled cooldown of the reactor coolant system occurred, which in turn initiated

SGIS and SIAS actuations. The SGIS actuation resulted in a main steam isolation valve closure, which disabled the main feedwater pumps (high pressure feedwater supply) and the TBVs, and caused a loss of the normal heat removal system.

CCNPP subsequently determined that the Quick Open signal failed to reset because an RRS X-channel K-7 relay contact failed to open when the relay was de-energized. The K-7 relay had last functioned properly, following a reactor trip, on May 28, 2003. CCNPP determined that the degraded relay contacts would probably have failed to open next time that the relay de-energized, following the May reactor trip. The inspectors concluded that the degraded RRS relay left the plant susceptible to an over-cooling event from May 28, 2003 to January 23, 2004.

The failed relay, along with two similar relays, were sent to an independent laboratory for failure modes and effects analysis. The laboratory analysis report identified that the failed relay contacts had extensive burning and pitting, consistent with electrical welding of the contacts. In addition, the report stated that arcing had occurred, as evidenced by burn marks inside the relay case, and that flash-over had deposited soot on one adjacent contact. The laboratory concluded that the failure was due to "burning and/or welding" of the contacts, but could not determine whether (1) inductive-kick, (2) excessive load, or (3) a one-time event initiated the contact burning that lead to the contact failure.

The CCNPP Root Cause Analysis Report (RCAR), "Failure of Atmospheric Dump Valve Quick Open Override Relay (K-7)," concluded that the root cause was a poor design practice during original plant construction and a subsequent 1992 modification (FCR 85-0068). The RCAR conclusion was based on the following facts and reasoning:

- The relay contacts were not rated for the actual circuit voltage; rated for 29 VDC, but installed in a 125 VDC circuit, and therefore failed prematurely.
- The relay (Allied Controls model MHJLO-12A) was a system interface device between the RRS system (Combustion Engineering design scope) and the ADV and TBV valve actuator 125 VDC circuit (Bechtel design scope).
- Laboratory failure analysis attributed the failure to an over-current event.
- The contacts had not reasonably reached end-of-life, and the steady state load current was low, compared to the contact current rating (no excessive load).
- Other than the failed (welded closed) contact pair, the relay was in good mechanical and electrical condition.
- In 1992, the ADV and TBV valve actuator circuits were modified (FCR 85-0068). A second load was added into the circuit controlled by the K-7 relay contacts. The contact ratings for the K-7 relay were not checked to verify that they were adequate for the additional load.

The RRS modification FCR 85-0068 specified specific design reviews and analysis requirements. The inspectors determined the specified requirements were not adequately performed, in that a required electrical analysis for the added loading on the existing ADV and TBV control circuit did not verify the K-7 contact ratings.

CCNPP's interim corrective actions replaced all K-7 relays in both Unit 1 and Unit 2, and performed targeted reviews, based on function and risk, of similar system interfaces to identify other underrated relay contacts. The interim action to install new K-7 relays reduced the likelihood of a premature contact failure, until a plant modification could be performed to eliminate the design deficiency. No other underrated relay contacts were identified. CCNPP's longer term corrective actions included a modification to the K-7 circuit to restore proper contact ratings for the circuit.

The inspector's review of CCNPP's RCAR analysis identified several weaknesses:

- The RCAR did not consider the third failure possibility that was identified in the laboratory analysis report, as a "one-time event" which could have initiated the contact burning that lead to the contact failure. Such a failure mode could have resulted from a maintenance error during testing activities.

- The RCAR did not discuss the testing and examination results of the other three K-7 relays, which had operated under similar conditions and length of service time (both Unit-1 K-7 relays and the second Unit-2 K-7 relay). Those relays were bench tested for contact resistence; two relays appeared to have adequately low contact resistence. The relays were also opened for an internal contact visual examination. The inspectors examined those relay contacts and noted evidence of excessive contact pitting on two relays.

- The RCAR did not discuss apparent contradictions in contact rating information provided by an Allied Controls relay applications engineer (original equipment manufacturer), and an independent root cause review conducted by an outside organization.

Overall, the inspectors concluded that while the CCNPP root cause determination was not thorough, the proposed corrective actions appeared reasonable.

<u>Old Design Issue Considerations</u>

In the original plant design (1977), the Combustion Engineering RRS design provided the K-7 relays as interface devices for a control signal output to the Bechtel designed ADV and TBV valve control system. The inspectors concluded that the K-7 relay contacts were underrated for their application since initial plant construction and startup.

NRC MC 0305, "Operating Reactor Assessment Program," Section 04.07 defines an "Old Design Issue" as a finding that involved a past design-related problem in an engineering analysis or installation of plant equipment (e.g., a modification), that does not reflect a performance deficiency associated with an existing program or procedure.

MC 0305 section 06.06(a) provides guidance for the treatment of Old Design Issues, and states that the NRC may refrain from considering safety significant findings if the Old Design Issue satisfies the following criteria:

- Licensee Identified.
- Not likely to have been previously identified by on-going licensee efforts.

Self-revealing issues are not considered to be licensee identified. In addition, CCNPP had a prior opportunity to identify this issue, during a 1992 modification to the ADV and TBV control system. Therefore, because this design-related finding did not satisfy the above criteria, it is not considered to be an Old Design Issue and is being treated similar to any other inspection finding, in accordance with MC 0305-06.06(a). This guidance is consistent with Section VII.B.3 of the NRC Enforcement Policy.

Analysis. This finding was a performance deficiency because CCNPP did not perform an adequate design review, as required by station procedures, during a 1992 modification to the Quick Open circuit. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding affected the Mitigating Systems cornerstone objective because it negatively impacted systems that are used to respond to initiating events to prevent core damage. This finding was more than minor because it was considered to be a precursor to a more significant event. If auxiliary feedwater (AFW) had not maintained steam generator level, once-through cooling would have been necessary to remove reactor decay heat. If once-through cooling and alternate feed had both failed, the sequence could have proceeded to core damage.

The finding was evaluated in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," using Phase 1, Phase 2, and Phase 3 significance determination process (SDP) analyze. The Phase 1 screening determined that a Phase 2 evaluation was required, because the finding represented an actual loss of a risk significant function of a non-Technical Specification equipment train that was classified as Maintenance Rule high safety significant, for greater than 24 hours.

A fault exposure time of 240 days was used for non-ATWS initiating events. On May 28, 2003, a reactor trip occurred, and the RRS quick open circuit and ADVs/TBVs functioned properly. Based on licensee review, the K-7 relay contacts would have failed to open on the next relay actuation, following the May reactor trip. There were no other demands or tests which would have demonstrated whether the quick open function was operational from May 28, until the reactor trip on January 23, 2004, when the RRS relay failure was identified by a self revealing event.

A fault exposure time of 28 days was used for ATWS initiating events. During the early part of an operating cycle, the RCS negative temperature coefficient is not be large enough (provide sufficient negative reactivity) to allow emergency boration (EB) to shutdown the unit given an ATWS. Based on licensee information this condition would last for 7 weeks if ADVs/TBVs operate properly and 11 weeks if ADVs/TBVs failed open. From a Phase 2 perspective this would equate to a 4 week exposure time where EB would not have functioned following startup from the May 28, 2003 trip.

The internal events Phase 2 analysis, for ΔCDF and ΔLERF, was conducted in accordance with IMC 0609 Appendix A, using the Risk-informed Inspection Notebook for Calvert Cliffs Nuclear Power Plant Units 1 and 2, revision 1, dated July 2, 2002 and with Draft IMC 0609, Appendix H, Containment Integrity SDP, respectively. From a Phase 2 perspective, the finding had low - moderate ΔCDF safety significance and very low ΔLERF safety significance.

The Region I senior reactor analyst (SRA) conducted a Phase 3 Risk Assessment, to refine the Phase 2 analysis and to incorporate external events for both ΔCDF and ΔLERF. The analysis used an update Calvert Cliffs SPAR model, Rev 3i, dated November 2001. The assumptions used were that a plant transient would result in an over-cooling event which would have caused SGIS and SIAS actuations. A SGIS actuation would close the MSIVs resulting in the loss of the main feedwater pumps as a high pressure feedwater supply and the inability to remove decay heat with the TBVs. The SIAS actuation would isolate the turbine building service water cooling system, resulting in the loss of the CBPs as a low pressure feedwater supply and in a loss of redundancy in instrument air supplies and in TDAFW room cooling.

The Phase 3 analysis determined that the finding represented low to moderate (WHITE) ΔCDF safety significance for internal and external initiating events. The internal events analysis resulted in a ΔCDF of approximately 2E-6 for the 240 day exposure period. The dominant core damage sequence was a transients with successful reactor trip followed by a loss of steam generator cooling and failure to initiate once through cooling (Feed and Bleed). An ATWS was the second dominant sequence, given the increased time that emergency boration would not be sufficient to shutdown the reactor with the TBVs/ADVs failing open. The finding represented a very low ΔLERF safety significance because there were no SGTR sequences identified as part of the SPAR analysis. The SRA reviewed the licensee's risk assessment relative to external events, finding that both fire and seismically induced transients contributed to the total CDF increase, but not to a sufficient extent to increase the total risk above low - moderate risk significance. Using similar assumptions to those used in the Phase 3 analysis CCNPP, using an integrated internal and external initiating events PRA model, estimated the ΔCDF safety significance at approximately 7E-6 for the 240 days.

Enforcement. There were no violations of NRC regulatory requirements because the reactor regulating system, atmospheric dump valves, and turbine bypass valves were not safety-related. CCNPP entered this finding into their corrective action program as IR4-025-059. **(FIN 50-318/2004008-01, Failure to Adequately Implement Modification Design Review of the Reactor Regulating System Quick Open Circuit.)**

2. Administrative Procedure for Control of Maintenance Activities

The inspectors identified that CCNPP did not implement written procedures for the control and revision of in-process maintenance work instructions. During the Unit 2 2003 refuel outage, MO 2-2002-01126 performed PM Checklist IPM56001, "Functional

Test of ADV and TBV Quick Open." That functional test was new, and had not previously been performed. Extensive pen-and-ink changes were made to the written work instructions, without utilizing the formal PM revision process, as required by MN-10-102 section 5.1, "PM Change Process." MN-10-102 section 5.2.B(d) limited pen-and-ink changes to "Administrative or Editorial" changes. The inspectors determined that the changes made were technical in nature, in that they changed the method of performing the test. The inspectors did not identify any additional similar examples, and concluded that this appeared to be an isolated example of this behavior.

Technical Specification 5.4.1 required, in part, that written procedures shall be established and implemented as recommended in NRC Regulatory Guide (RG) 1.33 Appendix A. RG 1.33 Appendix A, section 1.d, "Administrative Procedures," required written procedures for procedure adherence and temporary changes. The inspectors determined that this was a minor violation of regulatory requirements, because the failure to adequately review and approve the Checklist procedure change did not, in this instance, impact the final test results. CCNPP entered this issue into their corrective action program as IR4-036-977.

3. Maintenance Rule Classification & Monitoring of Quick Open Function

The Maintenance Rule (MR) basis document stated that the RRS control system (quick open signal & modulating control signal to ADVs & TBVs) was classified as MR high safety significant. The TBV and ADV valve control functions were scoped as part of the main steam system. The TBVs were classified as a MR non-risk function. The ADVs were classified as a MR high safety significant function. All functions were monitored for reliability (functional failures) at the system level. Only the ADV function was monitored for availability. The ADV and TBV functions were identified as "operate on demand" (i.e., a standby function).

CCNPP’s Loss of Normal Heat Removal analysis indicated that component failures which resulted in a loss of the normal heat removal system were risk significant. The inspectors noted that there was an apparent discrepancy between the MR classification and the risk significance, as determined by the station’s probability risk assessments.

NRC Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance," endorses NUMARC 93-01, and provided guidance for MR implementation. Both documents stated that high safety significant functions and standby low safety significant functions should have performance criteria established to assure reliability and availability are maintained. The inspectors concluded that the Quick Open function (RRS, ADVs, and TBVs) should reasonably have been monitored for both functional failures and availability, at the train level. The inspectors reviewed the system’s material history and concluded that, prior to the January 2004 reactor trip, the Quick Open function would not reasonably have required goal setting and monitoring under the MR (a)(1) requirements. The inspectors concluded that, in this instance, not monitoring the Quick Open function for availability was a minor issue. CCNPP entered this issue into their corrective action program as IR4-035-902.

2.2 Unit 2 SIAS Actuation Signal Failure to Reset from Control Room

a. Inspection Scope

Following a reactor trip on January 23, 2004, during the plant recovery phase of the event, the control room operators were unable to reset the "B" channel of SIAS.

The inspectors reviewed the SIAS system design, testing, and surveillance program elements, and interviewed plant personnel to independently determine what occurred and evaluate the initiating causal factors. The inspectors assessed CCNPP's cause determination and corrective actions to evaluate the adequacy of CCNPP's conclusions and actions.

The inspectors reviewed selected maintenance and modification activities associated with the SIAS system. The inspectors assessed post-maintenance and modification test adequacy by comparing the test methodology to the scope of work performed. In addition, the inspectors evaluated the test acceptance criteria to verify whether the test demonstrated that the tested components satisfied the applicable design requirements. The inspectors reviewed the recorded test data to determine whether the acceptance criteria were satisfied.

b. Findings

One self-revealing green finding and two inspector observations are documented in this section. The observations were minor issues that were related to the human performance cross-cutting area.

1. Failure to Adequately Implement Modification Work Instructions for Wiring Terminations

Introduction. A self-revealing finding of very low safety significance (Green) identified that maintenance procedures had not been adequately implemented to terminate a wiring connection during a modification in the SIAS "B" channel reset circuit, in April 2003. As a result, during a plant event, recovery actions were delayed because operators were unable to reset the "B" channel SIAS actuation from the control room. This finding was related to the Human Performance cross-cutting area.

Description. In March 2003, CCNPP performed a modification on the SIAS reset circuitry. Post-modification testing (PMT) consisted of point-to-point wiring checks to verify that the newly installed or modified circuits conformed to design requirements. No operational or functional test of the SIAS reset function was performed. CCNPP determined that the reset function was not specifically credited in any design basis event and not identified as a safety function in the FSAR or Technical Specification Basis. Therefore, CCNPP concluded that logic system functional testing was not required to be performed on the SIAS reset circuits.

Following a reactor trip in January 2004, a SIAS actuation occurred, per plant design. Approximately 49 minutes into the event, operators attempted to reset the SIAS actuation signal, to allow recovery of pressurizer level and pressure control. However, "B" channel of SIAS could not be reset from the control room. At approximately 60 minutes into the event, an operator reset the "B" channel SIAS modules individually in the cable spreading room.

During post-event troubleshooting, a visual inspection in control room panel 2C10 identified a wire hanging free in the air. The loose wire was determined to have come off of hand-switch 2HS-6901 terminal 7, which was part of the daisy chain circuit for the SIAS "B" channel reset. CCNPP determined that the wire probably pulled off the hand-switch terminal during one of two maintenance activities, performed in the same panel in close proximity to the affected hand-switch (MOs 2200302348 and 2200302349, to replace containment air cooler fan control hand-switches), in August or October 2003.

The inspectors reviewed the modification installation work order 2-2000-00544, "Remove SIAS Contacts from Containment Purge Isolation and Hydrogen Purge." The inspectors were unable to evaluate the adequacy of the PMT because CCNPP had not retained the test record data (see 2.3 below). The inspectors were initially unable to determine whether the wire had mistakenly not been terminated during the modification installation process, or whether the wire had subsequently come loose during adjacent work in the panel. However, the inspectors determined that the SIAS panel wiring was safety related and seismic category-1. Therefore, the inspectors concluded that CCNPP did not properly terminate a wire to hand-switch 2HS-6901 during a previous modification, and the subsequent quality inspection process failed to identify the faulty termination.

<u>Analysis</u>. This finding was a performance deficiency because written work instructions were not adequately followed. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding was more than minor because the SIAS system was returned to service, following modification work, and subsequently became unable to perform its function as a result of the deficiency, similar to example 5.b in NRC Inspection Manual 0612 Appendix E, "Examples of Minor Issues." This finding affected the Mitigating Systems cornerstone objective to ensure availability, reliability, and capability of mitigating systems, because it was associated with the cornerstone attributes for human performance.

This finding was determined to have very low safety significance, and screened out as Green, using the NRC Significance Determination Process (SDP) Phase-1 screening worksheet for NRC MC 0609 Appendix A, "Reactor Inspection Findings for At-Power Situations." This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event. CCNPP entered this finding into their corrective action program as IR4-025-652 and IR4-028-080.

A contributing cause of the finding was related to the Human Performance cross-cutting area because maintenance technicians did not adequately implement written work instructions.

Enforcement. Technical Specification 5.4.1 required, in part, that written procedures shall be established and implemented as recommended in NRC Regulatory Guide (RG) 1.33 Appendix A. RG 1.33 Appendix A, section 9.a, "Procedures for Performing Maintenance," required pre-planned maintenance activities be performed in accordance with written procedures for maintenance that can affect the performance of safety related equipment. CCNPP modification work order 2-2000-00544 required, in part, that wires were properly terminated, in accordance with E-406, "Installation Standard - Main Control Board Wiring."

Contrary to the above, on January 23, 2004, a self-revealing event identified that on March 20, 2003, CCNPP did not adequately implement work order 2-2000-00544 instruction steps to terminate wiring added by the modification. Because this violation was of very low safety significance, and CCNPP entered this finding into their corrective action program (IR4-025-652 and IR4-028-080), this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000318/2004008-02, Failure to Adequately Implement Modification Work Instructions for Wiring Terminations.)**

2. Previous Corrective Actions for Compression Style Terminations

In 1997, Unit 1 had a reactor trip (LER 50-317/1997-009) which was a direct result from an improper compression style termination, on a similar, but non-safety related, control panel hand-switch. Calvert Cliff’s root cause analysis report (CCER 9701) had a corrective action (IR1-053-484) to evaluate the use of a different type of termination (such as a crimped lug, under the switch’s termination screw), to replace the compression style termination currently used. CCNPP engineering subsequently determined that the compression style termination was more reliable (ES 1998-00394). CCNPP's review of the current issue also contains a corrective action to evaluate use of a non-compression style termination. The inspectors concluded that CCNPP may have missed an opportunity to have prevented this failure.

3. Control of Testing Scope and Acceptance Criteria

The SIAS reset circuit PMT consisted of wiring continuity checks, performed by ME-001, "Wiring Verification." No functional or operational test of the SIAS reset circuit was performed. ME-001 required that a supervisor verify the list of "circuits or drawings" to be checked, prior to the wiring continuity checks. The inspectors identified that the supervisor's "circuit identification" was designated by drawing number. The inspectors determined that the designated drawings contained numerous circuits, cables, and schemes, many of which were not involved with the modification. The test points, for the point-to-point continuity checks, were not pre-planned and were only required to be performed on the portion of the circuit that was new or modified. The selection of the test points was considered a skill-of-the-craft attribute. The inspectors concluded that allowing the maintenance technicians to select the test points may not test all aspects of the modification that are required to be tested. In addition, the inspectors identified that the test procedure (ME-001) did not require supervisory review or approval of the test results.

10 CFR 50 Appendix-B Criterion XI, "Test Control," required, in part, that testing required to demonstrate that systems will perform satisfactorily shall be performed in accordance with written procedures which incorporate requirements and acceptance limits. In the instance of the SIAS reset circuit modification, the ME-001 wiring verification test was the only PMT performed. The inspectors determined that ME-001 did not contain adequate written requirements or acceptance criteria, because the testing scope was designated at the drawing level, not the individual circuit or wire level. The inspectors determined that this was a minor violation of regulatory requirements, because the inspectors did not identify any instance where this performance deficiency had impacted the final test results. CCNPP entered this issue into their corrective action program as IR4-023-641.

2.3 Test Records for Safety Related Work Not Retained by Document Control

a. Scope

The inspectors reviewed selected post-maintenance and post-modification test records to evaluate whether the retained quality assurance records were adequate to verify that the associated tests demonstrated that safety related systems could perform their intended functions, after completion of maintenance or modification activities.

b. Findings

Introduction. The inspectors identified a non-cited violation of very low safety significance (Green) because CCNPP did not retain records of test results, as required by 10 CFR 50 Appendix B, Criterion XVII, "Quality Assurance Records." Specifically, CCNPP did not retain wiring verification point-to-point test records for modifications of safety related circuits. As a result, after the records were transferred to Records Management, verification of the work performed could not be done. This finding was related to the Human Performance cross-cutting area.

Description. In February 2004, the inspectors were unable to independently verify whether post-modification testing (PMT) had been adequately performed for modification work order 2-2000-00544, "Remove SIAS Contacts from Containment Purge Isolation and Hydrogen Purge." CCNPP Records Management did not retain individual point-to-point wiring verification documents, as required by ME-001, "Wiring Verification." Without the required test records, there was no documentation to identify which circuits, wires, or schemes had been checked, and no documentation to identify from where-to-where that the continuity checks had been performed.

For the SIAS reset circuit modification, no additional operational testing of the SIAS reset function was performed. The PMT relied entirely on the point-to-point wiring verification tests to verify SIAS reset circuit functionality. ME-001 section 6.3 required schematic drawings to be highlighted with the actual circuit locations where the point-to-point wiring checks had been performed. ME-001 section 7 required that all highlighted drawings and data sheets be attached to the initiating maintenance work order. ME-001 section 9 required that the records generated by the procedure were to be identified as permanent and retained for the lifetime of the plant.

CCNPP retained quality assurance safety related paper records by converting them into electronic records through an optical imaging process. The inspectors identified that in 1999, a revision to a CCNPP Records Management checklist excluded the ME-001 highlighted drawings as records which were required to be optically imaged. The marked-up drawings were highlighted in color, but the imaging system could not image color.

Analysis. This finding was a performance deficiency because written procedure instructions were not implemented. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding was more than minor because the failure to retain the required records was not an isolated example, and the records were irretrievably lost, similar to example 1.b in NRC Inspection Manual 0612 Appendix E, "Examples of Minor Issues."

This finding was not suitable for an NRC Significance Determination Process evaluation, but was reviewed by NRC management and determined to be of very low safety significance (Green). This finding would have been considered as potentially greater than very low safety significance if the missing test records had been associated with inadequate testing that had been linked to subsequent equipment failures which resulted in an event of greater than very low safety significance. CCNPP entered this finding into their corrective action program as IR4-025-931.

A contributing cause of this finding was related to the Human Performance cross-cutting area because station personnel did not adequately implement written instructions in a safety related procedure.

Enforcement. 10 CRF 50 Appendix B, Criterion XVII, "Quality Assurance Records," required, in part, that sufficient records shall be maintained to furnish evidence of activities affecting quality, including results of tests. The CCNPP Quality Assurance (QA) Policy, revision 57, stated that the QA Program satisfied the requirements of American National Standards Institute (ANSI) N18.7-1976 for administrative controls and quality assurance of safety related plant activities. ANSI N18.7 section 5.2.17, "Inspections," required that records shall be kept in sufficient detail to permit adequate confirmation of the inspection program. CCNPP safety related procedure ME-001, "Wiring Verification," section 7 and 9, required all highlighted drawings and records generated by the procedure to be retained for the life of the plant. Contrary to the above, on March 26, 2004, the inspectors identified that CCNPP had not retained test records, as required by ME-001, since approximately 1999.

Because this violation was of very low safety significance, and CCNPP entered this finding into their corrective action program (IR4-025-931), this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000318/2004008-03, Test Records for Safety Related Work Not Retained by Document Control**)

2.4 Unit 1 Digital Feedwater Design Deficiency

a. Inspection Scope

The inspectors reviewed the design deficiency in the digital feedwater system and its effect on the loss of feedwater to the 11 steam generator which resulted in a Unit 1 reactor trip on March 20, 2004. The inspectors reviewed the digital feedwater control system design, interviewed plant personnel to independently determine what occurred and evaluated the initiating causal factors. The inspectors assessed CCNPP's cause determination and corrective actions to evaluate the adequacy of CCNPP's conclusions and actions.

b. Findings

Introduction. A self-revealing event identified a finding because CCNPP failed to perform an adequate design review, as required by station procedures. This resulted in reduced reliability of the digital feedwater system and subsequently caused the Unit 1 reactor trip on March 20, 2004.

Description. On March 20, 2004, during maintenance on the 1-ER-101, "500 KV Bus Voltage" chart recorder technicians created a short circuit on the "C" phase of instrument bus 1Y09. Instrument bus 1Y09 is a three phase ungrounded AC system and since this is a three-phase ungrounded system the voltage on the other phases ("A" & "B") increased. The normal AC power for the 11 steam generator digital feedwater control system is supplied by the "B" phase from instrument bus 1Y09. The increase in voltage on the "B" phase resulted in metal oxide varistor (varistor) failures in the digital feedwater position indicators for the feedwater regulating valve. These failed varistors acted as a short circuit and opened a fuse in the normal power supply to the digital feedwater control processor. The power supply automatically transferred to the backup AC power supply from instrument bus 1Y10, but since the failed varistors were still in the circuit, the fuse from the backup power supply opened which removed both the normal and backup AC power to the 11 steam generator digital feedwater control system. The digital feedwater regulating valve failed to automatically transfer to DC control, which resulted in closing the regulating valve, reducing the level in 11 Steam generator resulting in a subsequent reactor trip.

Calvert Cliffs had previously determined that the design of the digital feedwater position indicators for the feedwater regulating valve and bypass valves were not designed for the higher voltages that a three-phase ungrounded system could sustain with one phase shorted. Calvert Cliffs failed to correctly specify the power supply voltages on the digital feedwater position indicators as required by ES-021, “Design Input Requirements Preparations.” The design input requirement evaluation concluded that the power supply for the position indicators, which include the varistors, were approximately 115 VAC. However, since the power supply is a three-phase ungrounded system the varistors could be expected to experience voltages as high as 208 VAC during a fault condition. Therefore, under the conditions experienced, the varistors failed, which resulted in reduced reliability of the feedwater digital control system and resulted in the reactor trip.

Analysis. This finding was a performance deficiency because CCNPP did not perform an adequate design review, as required by station procedures ES-020, “Impact Screens for the Engineering Service Process,” and ES-021, “Design Input Requirements Preparation.” Calvert Cliffs did not properly identify and evaluate critical aspects of the electrical power supply. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding affected the Initiating Events cornerstone objective because it contributed to increasing both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions will not be available. This finding was more than minor because it effects the design control attributes of the Initiating Events cornerstone. Incorrectly specifying the design voltage resulted in reducing the reliability of the digital feedwater control system which increased the likelihood of an event that upset plant stability during power operation.

The finding was determined to be of very low safety significance (Green), using the NRC Significance Determination Process (SDP). The Phase-1 screening determined that a Phase-2 evaluation was required because the finding affected both the Initiating Event and Mitigating Systems Cornerstones. In the Phase 2 risk analysis, the Transient and Loss of Component Cooling Water (LOCCW) initiating events were reviewed, as specified the Calvert Cliffs Plant Specific Risk Notebook. For Transients, the initiating event frequency was increased by one order of magnitude, because the digital feedwater control issue increased the likelihood of a loss of feedwater. For both the Transient and LOCCW SDP worksheets, the mitigation credit for the power conversion system (PCS) was decreased by one order of magnitude, because the feedwater system was less redundant with only one feed path available. The dominant core damage sequence was a transient, with successful reactor trip, followed by a loss of steam generator cooling and failure to initiate once through cooling (Feed and Bleed). The Phase-2 analysis determined that this finding was of very low safety significance (Green), because the finding did not affect the auxiliary feedwater system, and one of two turbine driven feedwater pumps remained available.

Enforcement. There were no violation of NRC regulatory requirements because the affected equipment was not safety-related. Calvert Cliffs entered this finding into their corrective action program as IR200400168. **(FIN 50-317/2004008-04, Failure to**

Adequately Implement a Modification Design Review of the Digital Feedwater Control System)

3.0 Human Factors and Procedural Issues

3.1 Failure to Properly Implement Station Emergency Operating Procedures

a. Inspection Scope

The inspectors reviewed the licensed operator performance following the Unit 2 reactor trip on January 23, 2004. Specifically, the inspectors looked at operator use of the emergency operating procedures (EOPs) and previous related training provided to the operators, and compared operator actions to procedural requirements.

b. Findings

Introduction. The inspectors identified a Green finding because CCNPP did not follow procedural requirements in their implementation of EOP-0, “Post-trip Immediate Actions,” and EOP-1, “Reactor Trip.” The operator’s mis-diagnosed plant conditions in EOP-0 and incorrectly proceeded to EOP-1 rather than EOP-4, “Excess Steam Demand Event.” Further, once in EOP-1, the operators failed to comply with the direction of that procedure. These failures to follow station procedures complicated the plant’s post-trip response and the ability of the operators to restore normal plant conditions.

Description

Procedure Implementation

Following the Unit 2 reactor trip on January 23, the control room operators entered procedure EOP-0. This procedure is organized around critical safety functions which must be satisfied when a reactor trip occurs, to ensure that the plant is placed in a stable, safe condition or that the plant is configured to further respond to a continuing casualty. When the ADVs and TBVs remained open following the trip, RCS temperature, pressurizer pressure and pressurizer level deviated from the acceptance values in EOP-0. While in EOP-0, operators attempted to recover these parameters to the values expected after a normal reactor trip. As part of that effort, the operators implemented steps of EOP-4 out of sequence in order to attempt to restore RCS parameter values. Following the SIAS, the safety injection compounded these out-of-sequence operator actions, and the pressurizer was overfilled with a large mass of cold water. RCS pressure was then dominated by this large volume of cold water, not the smaller-than-usual steam vapor bubble. The pressurizer bubble slowly lost its energy to the colder water volume, and pressure began to decrease, leading to the second SIAS.

In addition, the operators also incorrectly exited EOP-0 to go to EOP-1 when both the RCS Pressure/Inventory Safety Function and the Core/RCS Heat Removal Safety Function were not met. The diagnostic flowchart in EOP-0 directs the use of EOP-1 only when all safety functions are met. In this case, with two safety functions not met, EOP-0 directs the implementation of EOP-4. However, the operators should have been able to correctly enter EOP-4 even after entering EOP-1. Procedure EOP-1 requires that the diagnosis of an uncomplicated trip is correct by verifying the Safety Function Status Checks Intermediate Acceptance Criteria are satisfied. If any parameter does not satisfy the Intermediate Acceptance Criteria, and cannot be readily returned to within the Acceptance Criteria, the operator should perform EOP-8, “Functional Recovery Procedure,” or re-diagnose the event using the EOP-0 diagnostic flowchart and implement the appropriate procedure. On January 23, 2004, the Unit 2 operators identified that the RCS Pressure and Inventory parameters and the Core and RCS Heat Removal parameters did not satisfy the safety function status checks for at least the first 12 intermediate checks, yet the operators remained in EOP-1 and did not re-diagnose the event and did not implement the appropriate procedure, which in this case was EOP-4.

Also contributing to the improper use of the EOPs was the operator’s implementation of the provisions of procedure NO-1-201, “Calvert Cliffs Operating Manual.” Section 5.1C of that procedure allows deviation from controlling technical procedures to prevent conditions directly adverse to personnel safety, plant safety, plant stability, or the safety of the public. The procedure does not include a required condition that no other approved procedure is available (as is required by 10CFR50.54(x) and ANSI Standard N18.7/ANS 3.2-1976, Section 5.2.2). On January 23, operators used the provision of NO-1-201 to deviate from EOP-0 and EOP-1 when in fact other procedures were available to be used to mitigate this event.

Licensed Operator Training

Calvert Cliffs has increased the time allowed to execute EOP-0, to allow the operators to concurrently implement procedure steps from other EOPs, without executing the entire EOP. Calvert Cliffs allows this practice while in EOP-0, so that key plant parameters can be restored to normal operating bands. This philosophy resulted in the operators performing actions using knowledge-based skills as opposed to procedure-base skills during high stress condition. This practice significantly increased the potential for operator errors, and in the case of the January 23, 2004 event, it resulted in improper transitions in the EOP procedures.

Analysis. This finding was a performance deficiency because the operating crew did not follow procedural requirements in their implementation of EOP-0, “Post-trip Immediate Actions,” and EOP-1, “Reactor Trip.” Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. The finding is greater than minor because it affected the Human Performance attribute of the Mitigating Systems cornerstone objective. This finding was determined to have very low safety significance, and screened out as Green, using the NRC Significance Determination Process (SDP) Phase-1 screening worksheet for NRC MC 0609 Appendix A, "Reactor Inspection Findings for At-Power Situations." This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event. CCNPP entered this finding into their corrective action program as IR4-025-167.

A contributing cause of the finding was related to the Human Performance cross-cutting area because licensed operators did not properly implement station emergency operating procedures.

Enforcement. Calvert Cliffs Technical Specification 5.4.1.b, states that written procedures shall be established, implemented, and maintained covering the emergency operating procedures required to implement the requirements of NUREG-0737. EOP-0 requires, when safety functions are not met following a reactor trip, the transition to the appropriate optimal recovery procedure EOP. EOP-1 requires, when Safety Function Status Checks Intermediate Acceptance Criteria are not satisfied, the return to EOP-0 or the use of EOP-8.

Contrary to the above, on January 23, 2004, licensed operators at Calvert Cliffs Unit 2 improperly implemented EOP-0, Post-trip Immediate Actions, and EOP-1, Reactor Trip. With several safety functions still not satisfied, the operators improperly went to EOP-1 from EOP-0 instead of proceeding to EOP-4 as required by EOP-0. Further, with Safety Function Status Checks Intermediate Acceptance Criteria not satisfied, the operators improperly remained in EOP-1 instead of returning to EOP-0 to re-diagnose the event.

Because this violation was of very low safety significance, and CCNPP entered this finding into their corrective action program (IR4-025-167), this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000318/2004008-05, Failure to Properly Implement Station Emergency Operating Procedures)**

3.2 Failure to Have Procedures Required by Regulatory Guide 1.33

a. Inspection Scope

The inspectors reviewed CCNPP procedures following the Unit 2 reactor trip on January 23, 2004. Specifically, the inspectors looked at procedures available to operators for the use of the Reactor Regulating System (RRS) and for contingency measures for use upon that system's failure.

b. Findings

Introduction: The inspectors identified a Green finding because CCNPP did not have any procedural guidance for the failure of the RRS during their implementation of EOP-0, "Post-trip Immediate Actions." Upon the reactor trip and the subsequent failure of the K7 relay in the X channel of the RRS, if the operators had switched to the alternate Y channel of RRS, the ADVs and TBVs would have properly controlled the RCS temperature and terminated the uncontrolled cooldown event.

Description: Calvert Cliffs Unit 2 did not have procedures specifically designed to combat the malfunction of the RRS. Although the station had procedural direction on how to change RRS channels, that direction was contained in the precautions of operating instruction OI-7, "Reactor Regulating System," rather than an alarm response procedure or abnormal operating procedure used to combat a malfunction. The RRS is designed to provide control functions for the steam dump valves (TBVs and ADVs) for quick opening to remove stored energy upon a reactor trip, using RCS T-ave and turbine trip as initiating signals. This quick open feature provides for automatic control of RCS T-ave and pressurizer pressure following a reactor trip. On January 23, when the RRS failed and incorrectly kept the TBVs and ADVs open, Unit 2 operators did not have proper procedural guidance direct their response to the RRS malfunction event, forcing them to improperly use parts of different EOPs to combat the resulting off-normal RCS T-ave and pressurizer pressure and level parameters.

Analysis: This finding was a performance deficiency because the CCNPP is required to have a written procedure to combat the malfunction of a pressure control system. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. The finding is greater than minor because it affected the Procedure Quality attribute of the Mitigating Systems cornerstone objective. This finding was determined to have very low safety significance, and screened out as Green, using the NRC Significance Determination Process (SDP) Phase-1 screening worksheet for NRC MC 0609 Appendix A, "Reactor Inspection Findings for At-Power Situations." This finding had very low safety significance because the finding did not represent an actual loss of a safety function, and was not potentially risk significant due to an external initiating event. CCNPP entered this finding into their corrective action program as IR4-018-361.

Enforcement: Calvert Cliffs Technical Specification 5.4.1.a, states that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. That Regulatory Guide specifies procedures for "abnormal, offnormal, or alarm conditions" and procedures for "combating emergencies and other significant events," including the malfunction of a pressure control system.

Contrary to the above, on January 23, 2004, licensed operators at Calvert Cliffs Unit 2 did not have a specific procedure to respond to the abnormal condition created by the malfunction of the RRS, a pressure control system. Because this violation was of very low safety significance, and CCNPP entered this finding into their corrective action program (IR4-018-361), this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000318/2004008-06, Failure to Have Procedures Required by Regulatory Guide 1.33)**

3.3 Simulator Fidelity Issues

a. Inspection Scope

Through operator and training department interviews, and through licensee document review, the inspectors reviewed the licensed facility's control room simulator and its ability to accurately reproduce the events of January 23, 2004. Specifically, the inspectors looked at the simulator model replication of the RCS pressure and temperature transients observed that day by the control room operators.

b. Findings

No findings of significance were identified.

Observations

Calvert Cliffs identified a difference between the plant's RCS pressure and pressurizer temperature parameter response when the Unit 2, January 23 reactor trip was replicated on the plant specific simulator. Calvert Cliffs validates plant trips on their simulator to verify simulator fidelity. The validation of the January 23 reactor event, including the reactor trip and post-trip equipment and operator actions, revealed substantial differences in actual and predicted RCS pressure and temperature during the initial depressurization and subsequent repressurization. Specifically, after the TBVs and ADVs were shut, a plant heat-up occurred, and pressurizer level and RCS pressure increased in both the plant and the simulator. Operator action was required in the plant to stop the RCS pressure increase, but no operator action was required in the simulator to stop and control the RCS pressure. This contributed to the operators not fully comprehending the behavior of pressurizer parameters, particularly the pressurizer bubble-water mass energy interface.

Calvert Cliffs identified the cause of the fidelity issue as deficiencies in the original simulator software model that was installed in 1985. The licensee identified that the discrepancy between plant and simulator responses was due to three simulator model coefficient deficiencies. The Calvert Cliffs plant specific simulator did not correctly replicate RCS pressure and pressurizer temperature for this excess steam demand event. The differences between the actual plant response and the response previously experienced by the operators in their simulator training confused the operators and complicated the recovery of plant parameters following the Unit 2 reactor trip. However, enforcement action was not pursued due to the apparent cause of the issue being an original design issue, the identification of which was beyond the scope of expected and required testing.

3.4 Failure to Comply with Station Work Control Procedures

a. Inspection Scope

The inspectors reviewed CCNPP work control practices and decision-making processes which led up to the reactor trip on March 20, 2004, at Unit 1. Specifically, the inspectors interviewed licensed operators, managers, and maintenance staff who had been involved in the decisions to defer the replacement of vulnerable components in the digital feedwater system, those who had been involved in the scheduling of electrical work during the week of March 14, and those who were immediately involved on March 20. The inspectors reviewed CCNPP work control procedures and compared CCNPP actions against those procedural requirements and expectations.

b. Findings

Introduction. This self-revealing event identified a Green finding because CCNPP did not follow procedural requirements in their risk assessment and control of the work that was performed March 20, 2004, on Unit 1. Specifically, the provisions and controls of procedures NO-1-100, “Conduct of Operations,” NO-1-117, “Integrated Risk Management,” and MN-1-100, “Conduct of Maintenance,” were not followed. These failures to follow station procedures impacted the Initiating Events cornerstone in that the failure to properly classify and control the work in the control room on March 20 lead to an unanticipated reactor trip.

Description. In February 2004, a maintenance order was generated to repair the 500KV Bus Voltage Recorder 1ER-101 because the chart paper was not advancing. This piece of equipment is owned by the Generation Protections and Test Unit (GPTU), and that group was scheduled to be onsite March 20 to perform other site work. Based on that scheduling, the work on the recorder was placed on that week’s work schedule as emergent work. Calvert Cliffs records and NRC interviews of CCNPP staff show that the NO-1-117 work control/risk assessment process was implemented during the week of 3/14, yet a number of barriers failed or were bypassed:

1) No one involved in the scheduling or performance of the 1ER-101 recorder work recognized that the work involved the 1Y09 bus, and that the work should have gotten additional management attention, per the prior management decision made last year. The exact nature of the intended 1Y09/10 work prohibition or control was not clear due to the lack of documentation.

2) No one involved in the scheduling or performance of the 1ER-101 recorder work recognized that the work involved a trip sensitive area as defined in NO-1-100. Therefore, the additional preparation and oversight required by NO-1-100 were not implemented. The inspector also identified that the current revision of NO-1-100 directs the requirements of MN-1-124, "Conduct of Integrated Work Management," be followed for work in trip sensitive areas, yet those requirements in essence had been relocated to NO-1-117 without a change to the NO-1-100 procedure direction.

3) The risk assessments performed by the responsible group supervisor (RGS) and outage work control (OWC) in accordance with NO-1-117 incorrectly rated the 1ER-101 work as low risk. Due to the work being performed in a trip sensitive area and due to the previously identified vulnerability of the feedwater control system to work involving the 1Y09 bus, this work should have been rated as medium risk. The additional controls associated with a higher risk assessment were not implemented.

4) The actual 1ER-101 work was not performed in accordance with the expectations of MN-1-100, in that the pre-job briefing committed to using STAR, supervisory oversight, and peer checks as defenses to prevent errors. The failure to implement these practices directly led to the pinching of the power supply wire during the reinstallation of the 1ER-101 and the creation of the ground which initiated the reactor trip event.

When work was done on the 1ER-101 recorder, a piece of equipment powered by the 1Y09 bus, the lack of increased oversight and control of the work allowed a ground to be created, and all AC power to the Unit 1 digital feedwater control system was lost. This failure, combined with a latent failure in the DC power control system, led to an actual partial loss of feedwater event and a Unit 1 reactor trip.

Analysis. This finding was a performance deficiency because CCNPP did not properly risk-assess the work planned for March 20 nor did they put in place the proper precautions for the work, as required by station procedures. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding was more than minor because the combination of procedural non-compliances was considered to be a precursor to a more significant event, and it affected the Significance Determination Process Initiating Event Cornerstone by being a transient initiator contributor (i.e., directly led to an unplanned reactor trip). The finding screened to Green because the procedural non-compliances did not contribute to a LOCA initiator, contribute to the likelihood mitigation equipment would not be available, or increase the likelihood of a fire or flood.

A contributing cause of the finding was related to the Human Performance cross-cutting area because CCNPP managers and staff did not properly implement station operations, risk management, and maintenance procedures.

Enforcement. No violation of regulatory requirements occurred. The inspectors determined that the finding did not represent a noncompliance because it occurred on non-safety-related secondary plant equipment. CCNPP entered this finding into their corrective action program as IR4-028-774. **(FIN 50-317/2004008-07 Failure to Comply with Station Work Control Procedures)**

4.0 Emergency Preparedness

4.1 Failure to Recognize and Report an Unusual Event During the January 23, 2004, Unit 2 Reactor Trip

a. Inspection Scope

The inspectors reviewed the CCNPP implementation of the emergency plan during the January 23, 2004, Unit 2 reactor trip. The inspectors conducted interviews with licensed senior reactor operators (SRO), reactor operators (RO) and station support staff. The inspector reviewed station procedures and industry guidance and then compared the operator's performance to station procedures and industry guidance documents.

b. Findings

Introduction. The inspectors identified a non-cited violation of very low safety significance (Green) because the CCNPP operating staff and post trip review did not recognize that plant conditions required an emergency level classification (Unusual Event) in accordance with station procedures. As a result, CCNPP did not correctly implement the station emergency plan as required by 10CFR50.54(q). This finding was related to the Human Performance cross-cutting area.

Description. During the Unit 2 reactor trip and subsequent failure of the Reactor Regulating System, the ADVs and the TBVs failed open for approximately nine minutes. This resulted in an uncontrolled RCS cooldown which emptied the pressurizer, resulted in an automatic SIAS actuation, and a SGIS isolation. This excessive cooldown event was partially terminated by the SGIS isolation which isolated the TBVs and was finally terminated when the operators regained local control of the ADVs.

During this event the operators identified that the open TBVs and ADVs were not responding as designed. However, when evaluating plant conditions, the operators did not correctly conclude that the cause of the conditions (failed open TBVs and ADVs) were unexplained. Since the operators did not understand why the valves had failed to reclose they should have concluded that the condition was unexplained. This would have resulted in a determination that plant conditions met the entry conditions for EOP-4, “Excessive Steam Demand Event,” and required an Unusual Event classification. The CCNPP emergence action level (EAL) classification matrix specified that “EOP-4, Excess Steam Demand Event is Implemented,” met the criteria for an Unusual Event. Unexplained lowering of one or both steam generator pressure are entry conditions into EOP-4, “Excessive Steam Demand Event.” These plant conditions were present, and Station procedure NO-1-201, “Calvert Cliff’s Operating Manual,” requires classification of an event when the plant condition meets the emergency classification criteria. Therefore, the licensed operators should have reasonablely identified that an Unusual Event classification was required.

During the post-trip review, CCNPP concluded that an Unusual Event declaration was not required because EOP-4, “Excessive Steam Demand Event,” entry conditions were not met. The review concluded that the source of the excessive steam demand was the failed open TBVs and ADVs, and because the cause of the excessive steam demand was known, the entry condition for EOP-4 was not met. Therefore, this review concluded that EOP-4 was not entered and no Unusual Event declaration was required. The post trip review incorrectly concluded that the cause of the failed open TBV and ADVs was explained. The failed open TBVs and ADVs were not responding as designed and met the entry conditions for EOP-4. Therefore, these plant conditions were commensurate with an Unusual Event. During the week of January 17, 2004, the inspectors discussed the Unusual Event classification with CCNPP. On May 28, 2004, CCNPP completed a 1-hour report in accordance with 10 CFR 50.72(a)(1)(i) for this event.

Analysis. The inspectors determined that this finding was a performance deficiency because CCNPP operating staff did not recognize plant conditions commensurate with an Unusual Event and therefore, the plant operating staff did not declare an Unusual Event nor did the post-trip review identify the Unusual Event. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements or CCNPP procedures. This finding was more than minor because it effects the response organization performance attribute of the Emergency Preparedness Cornerstone in that failure to recognize plant conditions indicative of an Unusual Event resulted in not identifying the Unusual Event. The finding was assessed using MC 0609, Appendix B, “Emergency Preparedness Significant Determination Process,” sheet 2, “Actual Event Implementation Problem.” The finding was determined to be of very low safety significance (Green) because the operators failed to identify Unusual Event conditions during an actual plant event.

This finding is related to the Human Performance cross-cutting area because reactor operators and the Unit 2 post trip review did not recognize plant conditions commensurate with an Unusual Event and did not report the Unusual Event prior to prompting by the NRC.

Enforcement. This was a violation of 10CFR50.54(q) which states in part that licensees shall follow their emergency plans. The CCNPP Emergency Response Plan, Section 4.0, “Emergency Measures,” states "Emergency Response Plan Implementing Procedures contain procedures and guidance for accident assessment and emergency classification." ERPIP-3.0, Immediate Actions, Attachment 2 entitled "Emergency Classification" directs operators to evaluate plant conditions against EAL Criteria. Specifically, EAL QU5 states the conditions for an unusual event: "EOP-4, Excess Steam Demand Event is implemented." NO-1-201, "Calvert Cliff’s Operating Manual" states "During EOP-0, should it become apparent that an EAL condition is met, the classification should begin right away without waiting for the next EOP to be implemented."

Contrary to the above, the operating crew, in response to the January 23, 2004, reactor trip event, did not recognize plant conditions that were commensurate with an Unusual Event. The CCNPP post-event review did not identify that an Unusual Event should have been identified based on plant conditions. This violation has been entered in CCNPP corrective action program as IR4-023-606 and is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000318/2004008-08, Failure to Recognize an Unusual Event During the Unit 2 Reactor Trip)**

5.0 Cross Cutting Aspects of Findings

Section 2.2 describes a finding where maintenance technicians did not adequately implement written work instructions. As a result, during a plant event, recovery actions were delayed because operators were unable to reset the "B" channel SIAS actuation from the control room.

Section 2.3 describes a finding where station personnel did not adequately implement written instructions in a safety related procedure to maintain records that can be used to determine the scope of work performed on safety related components. The failure to retain the required records, as required by ME-001, since approximately 1999 resulted in the records being irretrievably lost

Section 3.1 describes a finding where licensed operators did not properly implement station emergency operating procedures. These actions resulted in the operators performing actions using knowledge-based information as opposed to skill-based information. This resulted in the operators selecting what actions should be performed out of station procedures based on plant indications, under high stress conditions which significantly increased the potential for operator errors, and in the case of the January 23, 2004 event, it resulted in improper transitions in the EOP procedures.

Section 3.4 describes a finding where CCNPP managers and staff did not properly implement station operations, risk management, and maintenance procedures. This resulted in a precursor to Unit 1 reactor trip on March 20, 2004.

Section 4.1 describes a finding where licensed operators and the post-trip review failed to recognize plant conditions commensurate with an Unusual Event during the January 23, 2004, Unit 2 excessive steam demand event.

6.0 Generic Issues

During this inspection, no significant issues were identified requiring the issuance of generic communications to the nuclear industry.

7.0 Risk Significance of the January and March 2004 Events

The team conducted an initiating event assessments and concluded that each event resulted in a moderate risk significance conditional core damage probability (CCDP) (between E-6 and E-5 per event). These risk assessments were conducted using the NRC's standardized plant analysis risk (SPAR) model for Calvert Cliffs. The model was updated to reflect the licensee's operating experience and procedures. The licensee also performed an initiating event assessments for these events and reached similar conclusions.

Unit 2 January Reactor Trip

The team concluded that this event resulted in a conditional core damage probability (CCDP) in the mid E-6 range. The following assumptions were used:

- A general plant transient occurred due to a partial loss of feedwater.
- The failure of the K-7 relay in the reactor regulating system resulted in the turbine bypass valves and the atmospheric dump valves remaining full open and not modulating to control reactor plant parameters, which resulted in an uncontrolled cooldown of the reactor coolant system. As a result, steam generator isolation and safety injection actuation signals were generated to mitigate the event.

The dominant accident sequences for this transient event were: 1) failure of steam generator cooling and Failure of once through core cooling; 2) failure of the reactor protection system to shutdown the reactor and failure to limit reactor coolant system pressure; and 3) failure of the reactor coolant pump seals and failure of high pressure recirculation.

Unit 1 March Reactor Trip

The team concluded that this event resulted in a CCDP in the low E-6 range. The following assumptions were used:

- A general plant transient occurred due to a partial loss of feedwater. The main feedwater flow path to SG11 was unavailable due to the digital feedwater control system failure.

- Turbine bypass valves fast opened but failed to stay open to control pressure. This resulted in the need to use the atmospheric dump valves.

The dominant accident sequences for this transient event were: 1) failure of steam generator cooling and Failure of once through core cooling; 2) failure of the reactor coolant pump seals and failure of high pressure recirculation; and 3) failure of the reactor protection system to shutdown the reactor and failure to limit reactor coolant system pressure.

8.0 Overall Adequacy of Licensee Response

The team concluded that the overall response of CCNPP to the January 23, 2004, Unit 2 reactor trip and the March 20, 2004, Unit 1 reactor trip were adequate because the plants were taken to a safe shutdown condition. However, during both events the operators were challenged by equipment malfunctions that were the result of less than adequate design review and maintenance work. In addition, the operators had problems implementing emergency operating procedures during the Unit 2 reactor trip. The Unit 1 trip was the result of not correctly implementing work management control procedures. CCNPP had an opportunity in both cases to previously address the issues. CCNPP's corrective actions regarding equipment and procedures for this event have been appropriate. However, the CCNPP identification and reporting of the Unusual Event condition was delayed and had to be prompted by the NRC. These events show the need for improvements in the human performance areas.

9.0 Exit Meeting Summary

The NRC presented the results of this special inspection to Mr. George Vanderheyden, and other members of CCNPP management on June 18, 2004, via conference call. Calvert Cliffs management acknowledged the findings presented. No proprietary information was identified.

ATTACHMENT A

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:
T. Roberts, Supervisor - Electrical & Control Systems
M. McMahon, Supervisor - FIN Team
C. Yoder, Engineer - Electrical & Control Design
R. Stark, Senior Engineer - Electrical & Control Design
H. Winters, System Engineer
D. Lenker, Supervisor - Electrical and I&C Design
J. Kilpatrick, Senior Engineer - 50.59 Program
H. Daman, General Supervisor - Electrical and I&C Maintenance

R. Simmons, Supervisor - I&C Maintenance
S. Collins, System Engineer
E. Roach, Lead Assessor

NRC Personnel:
M. Giles, Senior Resident Inspector - Calvert Cliffs
R. Fuhrmeister, Senior Reactor Inspector
A. Della Greca, Senior Reactor Inspector
E. McKenna, NRR

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000318/2004008-01	FIN	Failure to Adequately Implement Modification Design Review of the Reactor Regulating System Quick Open Circuit (Section 2.1.b.1)

Closed

05000318/2004008-02	NCV	Failure to Adequately Implement Modification Work Instructions for Wiring Terminations (Section 2.2.b.1)
05000318/2004008-03	NCV	Test Records for Safety Related Work Not Retained by Document Control (Section 2.3)
05000317/2004008-04	FIN	Failure to Adequately Implement a Modification Design Review of the Digital Feedwater Control System (Section 2.4)
05000318/2004008-05	NCV	Failure to Properly Implement Station Emergency Operating Procedures (Section 3.1)
05000318/2004008-06	NCV	Failure to Have Procedures Required by Regulatory Guide 1.33 (Section 3.2)
05000317/2004008-07	FIN	Failure to Comply with Station Work Control Procedures (Section 3.4)
05000318/2004008-08	NCV	Failure to Recognize an Unusual Event During the Unit 2 Reactor Trip (Section 4.1)

LIST OF DOCUMENTS REVIEWED

Section 2.1 Reactor Regulating System Quick Open Circuit Failure

Issue Reports
IR4-025-059
IR4-028-151

Work Orders
MO 2-2004-00291

Design Bases
CCNPP Quality Assurance Policy, revision 57
FSAR Section 7.4.1, "Reactor Regulating System"

Procedures
Checklist IPM56001, "Functional Testing of ADV and TBV Quick Open"

Drawings
86924SH0001X, "Unit 2 RRS Channel-X Schematic"
86924SH0001Y, "Unit 2 RRS Channel-Y Schematic"
86924SH0002X, "Unit 2 RRS Channel-X Schematic"
86924SH0002Y, "Unit 2 RRS Channel-Y Schematic"
63069, "Turbine Steam Dump and Bypass Control Schematic"
12017-0101, "RRS Block Diagram"
12132-0050, "RRS Reactor Program Unit Calculator Function and Wiring Diagram"
86-922-E, "RRS Test Panel Schematic Wiring Diagram"

Other Documents
Modification Package FCR 85-0068
System Descriptions, System 56 and 83A
System Health Report, System 56 and 83A
Maintenance Rule Scoping Document, System 56 and 83A
Main Steam System Risk Significant Components Report, revision 0, dated 03/19/1998
NUMARC 93-01, revision 2, "Monitoring the Effectiveness of Maintenance"

Section 2.2 SIAS Actuation Signal Failure to Reset from Control Room

Issue Reports
IR4-025-652, "ESFAS SIAS "B" Would Not Reset from the Control Room"
IR4-028-080, "Signal for SIAS Reset is Not Tested from Control Room"
IR4-022-941, "Unexpected Second SIAS Actuation"

Work Orders
MO 2200000544, "Remove SIAS Contacts from Ctmt Purge Iso & H2 Purge"
MO 2200400304, "Check for Open Switch Contacts"
MO 2200302348, "Replace 23 CAC Hand Switch 2HS5301"
MO 2200302349, "Replace 24 CAC Hand Switch 2HS5302"

Design Bases
FSAR section 7.3, ESFAS
E-406, "Installation Standard - Main Control Board Wiring"
NRC Generic Letter 1996-01, "Testing of Safety Related Logic Circuits"
RG 1.187, "Guidance for Implementation of 10 CFR 50.59"

Procedures
ME-001, revision 0, "Wiring Verification"
STP-M-220B-2, "Engineered Safety Features Actuation System Channel ZE Functional Test"
PR-1-101, revision 20, "Preparation and Control of Technical Procedures"
EN-1-102, revision 8, "10 CFR 50.59 / 72.48 Reviews"
ES-017, revision 5, "10 CFR 50.59 Reviews"

Drawings
63076SH0042, "Schematic Diagram for Containment Vent & Hydrogen Purge"
63059, "Schematic Diagram for ESFAS"
63059A, "Schematic Diagram for ESFAS"
87310SH00002, "Wiring Diagram for Panel 2C10"

Other Documents
System Description No. 048, revision 2, "Engineered Safety Features Actuation System"
System Health Report for Systems 48 and 52
NEI 1996-07, revision 1, "Guidelines for 10 CFR 50.59 Implementation"

Section 2.3 Safety Related Test Records Not Retained

Issue Reports
IR4-025-652, "ESFAS SIAS "B" Would Not Reset from the Control Room"
IR4-028-080, "Signal for SIAS Reset is Not Tested from Control Room"

Work Orders
MO 2200000544, "Remove SIAS Contacts from Ctmt Purge Iso & H2 Purge"
MO 2200400304, "Check for Open Switch Contacts"

Design Bases
E-406, "Installation Standard - Main Control Board Wiring"
CCNPP Quality Assurance Policy, revision 57
ANSI N18.7-1976, "Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants"

Procedures

ME-001, revision 0, "Wiring Verification"

Drawings
61036, Rev. 62, "Schematic Diagram 208/120V Instrumentation Buses 11 & 12 Unit #1"for Containment Vent & Hydrogen Purge"
63059, "Schematic Diagram for ESFAS"
63059A, "Schematic Diagram for ESFAS"
87310SH00002, "Wiring Diagram for Panel 2C10"

Section 2.4 Unit 1 Digital Feedwater Design Deficiency

Issue Reports
IR200400168, “March 20, 2004, Unit 1 Reactor Trip During Scheduled Maintenance”

Procedures
ES-020, Rev. 10, “Impact Screens for the engineering Service Process”
ES-021, Rev. 04, “Design Input Requirements (DIR) Preparation”
EN-1-100, Rev. 16, “Engineering Services Process Overview”
EN-1-101, Rev. 06, “Design Change and Modification Implementation”

Analysis
ESP-199602497, Rev. 01, dated 11/27/2001
ESP-200001092. Rev. 03, dated 8/27/01

Drawings
61036, Rev. 62, "Schematic Diagram 208/120V Instrumentation Buses 11 & 12 Unit #1"
Simplified Drawing - Digital Feedwater Power Distribution System
Simplified Drawing - Digital Feedwater Power Scheme, Unit One Post 2002 RFO

Section 3.1 Failure to Properly Implement Station Emergency Operating Procedures

Issue Reports
IR200400053 23 Steam Generator Feed Pump Trip Resulting in Unit 2 Plant Trip, Root Causal Analysis (Issue Report IR4-028-786)
IR200400056, Unplanned SIAS Actuation Following Unit 2 Trip, Root Causal Analysis (Issue Report IR4-025-167)
IR4-025-059, Unit 2 Atmospheric Dump Valves Appear to Have Erroneous Open Signal From RRS Channel “X”
IR4-025-165, -166 & -167, POSRC Recommendations During 1/24/04 Post-Trip Review Meeting
IR4-028-786, Unit 2 Trip: Loss of 22 SGFP Resulted in Low SG Level Trip

Procedures
AOP-7K, Overcooling Event in Mode One or Two (Unit 2), Rev. 2
AOP-7K, Overcooling Event in Mode One or Two, Basis Document (Unit 1 & 2), Rev. 1
EOP-0, Post-Trip Immediate Actions (Unit Two), Rev. 8
EOP-0, Post-Trip Immediate Actions Technical Basis Document, Rev. 14
EOP-1, Reactor Trip (Unit Two), Rev. 12
EOP-4, Excess Steam Demand Event (Unit Two), Rev. 15
NO-1-100, Conduct of Operations, Rev. 23
NO-1-111, Post-Trip Review, Rev. 6
NO-1-200, Control of Shift Activities, Rev. 29
NO-1-201, Calvert Cliffs Operating Manual, Rev. 15

Training Materials
Lesson Plan LOI-201-0-9, EOP-0 Post-Trip Immediate Actions Scope and Basis for the Licensed Operator Initial Training Program
Lesson Plan LOR-63-1-02, ESFAS for the Licensed Operator Requalification Program
Lesson Plan LOR-201-0, 4-S-0-2, EOP-0, -1, and -4 Simulator Exercises for the Licensed Operator Training Program
Lesson Plan LOR-201-0-8-02, EOP Basis Review for the Licensed Operator Training Program
Lesson Plan LOR-348-1-04, Calvert Cliffs Operating Experience, With Thermodynamic Review, Unit 2 Trip 1/23/04

Other Documents
Unit 2 Control Room Operator Logs for January 23, 2004
Unit 2 Equipment Control Logs for January 23, 2004

Section 3.2 Failure to Have Procedures Required by Regulatory Guide 1.33

Design Bases
Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation)
Calvert Cliffs - Unit 2 Technical Specifications

Procedures

OI-7, Reactor Regulating System, Rev. 9
NO-1-100, Conduct of Operations, Rev. 23

Training Materials
Reactor Regulating System Description No. 56, Rev. 0
LOI-58-1-13, Reactor Regulating System for the License Operator Initial Training Program
Simulator Operating Examinations for the Licensed Operator Training Program (various)

Section 3.3 Simulator Fidelity Issues

Issue Reports
IR200400066, Simulator Fidelity Deficiency Root Causal Analysis (Issue Report IR4-020-078)

Procedures
AOP-7K, Overcooling Event in Mode One or Two (Unit 2), Rev. 2

Training Materials
Simulator Requal Session V, Scenario 03-03, Rapid Downpower with Expeditious Return to Full Power
Lesson Plan LOR-348-1-04, Calvert Cliffs Operating Experience, With Thermodynamic Review, Unit 2 Trip 1/23/04

Section 3.4 Failure to Comply with Station Work Control Procedures

Issue Reports
IR200400168, March 20 Unit 1 Reactor Trip Root Causal Analysis (Issue Report IR4-028-774)
IR4-000-887, Potential for Loss of AC Power to SG Level Control if Ground Occurs on 1Y09/10
IR4-028-847, 500KV Bus Voltage Recorder (1ER-101) Chart Paper Does Not Advance

Maintenance Orders
MO 1200400687, Replace 500KV Sensitive Voltage Recorder 1ER-101

Procedures
MN-1-100, Conduct of Maintenance, Rev. 22
MN-1-124, Conduct of Integrated Work Management, Rev. 6
NO-1-100, Conduct of Operations, Rev. 23
NO-1-117, Integrated Risk Management, Rev. 11
NO-1-200, Control of Shift Activities, Rev. 29
NO-1-201, Calvert Cliffs Operating Manual, Rev. 15
PR-1-103, Use of Procedures, Rev. 4

Section 4.0 Emergency Preparedness

Issue Reports
IR4-023-606, Event 4092, "Reactor Trip on 1/23/04 Met the Conditions of ERPRP UE Due to Excessive Steam Demand for 9 Minutes Following the Trip."

Procedures:
NO-1-201, "Calvert Cliffs Operating Manual"
EOP-4, Rev. 15, "Excess Steam Demand Event"
EOP-4 Basis Document
Calvert Cliffs EAL Technical Basis Manual, Rev. 10

Other:

Information Notice 85-80,	“Timely Declaration of an Emergency Class, Implementation of an Emergency Plan, and Emergency Notification.”
Information Notice 89-72,	“Failure of Licensed Senior Operators to Classify Emergency Events Properly.”

LIST OF ACRONYMS

ABT	Automatic Bus Transfer
ADV	Atmospheric Dump Valve
AFAS	Auxiliary Feedwater Actuation System
ANSI	American National Standards Institute
ARC	Alarm Response Card
AV	Apparent Violation
CBP	Condensate Booster Pump
CCDP	Conditional Core Damage Probability
CCNPP	Calvert Cliffs Nuclear Power Plant
CDF	Core Damage Frequency
CR	Condition Report
CRS	Control Room Supervisor
CST	Condensate Storage Tank
ΔCDF	Delta Core Damage Frequency
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
FRV	Feedwater Regulating Valve
FSAR	Final Safety Analysis Report
GPTU	Generation Protection and Test Unit
LER	Licensee Event Report
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NRC	Nuclear Regulatory Commission
OWC	Outage Work Control
PMT	Post Modification Test
PORC	Plant Operations Review Committee
QA	Quality Assurance
RCAR	Root Cause Analysis Report
RG	[NRC] Regulatory Guide
RGS	Responsible Group Supervisor
RHR	Residual Heat Removal
RRS	Reactor Regulating System
SGFP	Steam Generator Feedwater Pump
SDP	[NRC] Significance Determination Process
SGIS	Steam Generator Isolation Signal
SIAS	Safety Injection Actuation Signal
SRV	Safety Relief Valve
STAR	Stop, Think, Act, Review
TBV	Turbine Bypass Valve
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report

ATTACHMENT B

SPECIAL INSPECTION TEAM CHARTER

February 5, 2004

MEMORANDUM TO:	Richard J. Conte, Team Manager Division of Reactor Safety Alan J. Blamey, Team Leader Special Inspection
FROM:	Wayne D. Lanning, Director Division of Reactor Safety
SUBJECT:	SPECIAL INSPECTION CHARTER - CALVERT CLIFFS NUCLEAR POWER PLANT UNIT 2

A special inspection has been established to inspect and assess the automatic reactor trip that occurred at Calvert Cliffs Unit 2 on January 23, 2004. The special inspection will be conducted onsite during the week of February 17, 2004, to allow Calvert Cliffs to complete the root cause analysis for this event. The apparent cause review was completed prior to restart of the unit on January 25, 2004. The team will include:

Manager:	Richard J. Conte, Chief, Operational Safety Branch
Leader:	Alan Blamey, Senior Operations Engineer
Members:	John Richmond, Resident Inspector at Susquehanna Steve Barr, Operations Engineer Herb Williams, Operations Engineer Mark Giles, Senior Resident Inspector at Calvert Cliffs - Part Time Eugene Cobey, Senior Reactor Analyst - Part Time

Unit 2 was operating at 100% power when the 22 steam generator feed pump spuriously tripped. Operators were unable to reset and restart the pump, so they manually tripped the reactor. Just prior to the manual trip, the reactor automatically tripped due to low steam generator water level. The steam dump valves (atmospheric and condenser) fast opened as designed, but did not modulate to properly control RCS temperature. Operators had difficulty stabilizing RCS pressure such that a safety injection actuation signal occurred a second time during the first two hours after the reactor trip. Additionally, operators were unable to reset the safety injection actuation signal from the main control board, and some of the pressurizer back-up heaters were previously removed from service due to a leaking pressurizer spray valve, a known problem. The basis for this inspection is to independently evaluate equipment and human performance, and to assess Constellation’s root cause evaluation and corrective actions.

This special inspection was initiated in accordance with NRC Inspection Procedure 71153 "Event Follow-up" and NRC Management Directive 8.3, "NRC Incident Investigation Program." The decision to perform this special inspection was based on the initial risk assessment coupled with the various complications that occurred following the trip. The inspection will be performed in accordance with the guidance of NRC Inspection Procedure 93812, "Special Inspection," and the inspection report will be issued within 30 days following the exit meeting for the inspection. If you have any questions regarding the objectives of the attached charter, please contact me at (610) 337-5191.

Attachment: Special Inspection Charter

Distribution:
H. Miller, RA/J. Wiggins, DRA
J. Trapp, DRP
M. Giles, DRP
N. Perry, DRP
E. Cobey, DRS
J. Jolicoeur, RI EDO Coordinator
R. Laufer, NRR
G. Vissing, PM, NRR
R. Clark/P. Tam, PM, NRR (Backup)
W. Lanning, DRS
R. Crlenjak, DRS
B. Holian, DRP
D. Screnci, ORA

Special Inspection Charter
Calvert Cliffs Nuclear Power Plant Unit 2
Automatic Reactor Trip - With Equipment and Potential Human Performance Problems

The objectives of the inspection are to verify the facts and assess the issues surrounding the automatic reactor trip that occurred at Calvert Cliffs Nuclear Power Plant Unit 2 on January 23, 2004. Specifically the inspection should:

1. Independently evaluate the equipment and human performance issues to assess the adequacy of the scope of Constellation's investigation. This evaluation will:

    - Assess the adequacy of Constellation's investigation and root cause evaluation of the circumstances surrounding the cause of the automatic reactor trip and the post trip response from the perspective of the equipment performance and human performance.

    - Assess the adequacy of Constellation's plans for corrective actions and extent of condition review for the equipment and human performance issues.

2. Independently evaluate the quality of operator response, and their implementation of procedures, including Emergency Operating Procedures.

3. Assess the adequacy of testing activities, prior to the event, to verify equipment operability after maintenance or modification activities.

4. Assess the adequacy of programs (i.e., workarounds, configuration control, corrective action program) to address known equipment issues.

5. Independently evaluate the risk significance of the event.

6. Assess the effectiveness of related simulator and training issues.

7. Document the inspection findings and conclusions in a special inspection report in accordance with Inspection Procedure 93812 within 30 days of the exit meeting for the inspection.

ATTACHMENT B2

REVISED SPECIAL INSPECTION TEAM CHARTER

April 13, 2004

MEMORANDUM TO: Richard J. Conte, Team Manager
Division of Reactor Safety

Alan J. Blamey, Team Leader
Special Inspection

FROM: Wayne D. Lanning, Director
Division of Reactor Safety

SUBJECT: SPECIAL INSPECTION CHARTER - CALVERT CLIFFS NUCLEAR POWER PLANT UNIT 2 - SUPPLEMENTAL TO INCLUDE UNIT 1 TRIP

A special inspection had been established to inspect and assess the automatic reactor trip that occurred at Calvert Cliffs Unit 2 on January 23, 2004. As a result of a comparable conditional core damage probability, and similar deterministic factors related to operator performance, the Calvert Cliffs Unit 1 reactor trip of March 20, 2004, is now included in your team's review.

The special inspection will be conducted onsite on or about May 10, 2004, on a not to interfere basis with the Unit 1 startup from a refueling outage scheduled to start April 9, 2004. This is to allow Constellation Energy to complete the root cause analysis for Calvert Cliffs Unit 1 March 20, 2004, event. The apparent cause review was completed prior to restart of the unit on March 22, 2004. The team remains the same per the previous charter but implementation should be with less resources and less scope. For example since the post trip response for Unit 1 was less severe than Unit 2, the main focus of the Unit 1 review will be the 20 minutes before the trip when digital feedwater controls adversely responded to the loss of an instrument bus.

Unit 1 was operating at 100% power when technicians inadvertently grounded an instrument when reinstalling an instrument recorder. The grounding effected digital steam generator feedwater control system, eventually causing a loss of feedwater and an almost simultaneous automatic and manual reactor trips. Operators were unable to manually control the turbine bypass valves and the main condenser was lost for 10 hours. Just prior to the trip signal, the operators dealt with diagnosing the effect of the ground on digital feedwater control. No safety injection signals occurred and the post trip response was relatively benign, but there is a question on how procedures were implemented in the 20 minutes prior to the trip. The risk for this event increased due to the loss of the main condenser. The basis for this inspection is to independently evaluate equipment and human performance, and to assess Calvert Cliff's root cause evaluation and corrective actions.

This special inspection was initiated in accordance with NRC Inspection Procedure 71153 “Event Follow-up” and NRC Management Directive 8.3, “NRC Incident Investigation Program.” The decision to perform this special inspection was based on the initial risk assessment coupled with our knowledge of preliminary performance deficiencies for the Unit 2 trip of January 2004 and some uncertainty on how procedures were implemented in the 20 minutes prior to the Unit 1 trip. The inspection will be performed in accordance with the guidance of NRC Inspection Procedure 93812, “Special Inspection,” and the inspection report will be issued within 30 days following the exit meeting for the inspection. If you have any questions regarding the objectives of the attached charter, please contact me at (610) 337-5126.

Attachment: Special Inspection Charter

Distribution:
H. Miller, RA/J. Wiggins, DRA
J. Trapp, DRP
M. Giles, DRP
N. Perry, DRP
E. Cobey, DRS
J. Jolicoeur, RI EDO Coordinator
R. Laufer, NRR
G. Vissing, PM, NRR
R. Clark/P. Tam, PM, NRR (Backup)
W. Lanning, DRS
R. Crlenjak, DRS
B. Holian, DRP
D. Screnci, ORA
R. Conte, DRS
A. Blamey, DRP

Special Inspection Charter - Supplemental
Calvert Cliffs Nuclear Power Plant Unit 1
Automatic Reactor Trip - With Equipment and Potential Human Performance Problems

The objectives of the inspection are to verify the facts and assess the issues surrounding the manual and automatic reactor trip that occurred at Constellation's Calvert Cliffs Nuclear Power Plant Unit 1 on March 20, 2004. Specifically, the inspection should:

1. Independently evaluate the equipment and human performance issues to assess the adequacy of the scope of Constellation's investigation. This evaluation will:

    - Assess the adequacy of Constellation's investigation and root cause evaluation of the circumstances surrounding the cause of the automatic reactor trip and the post trip response from the perspective of the equipment performance and human performance.

    - Assess the adequacy of Constellation's plans for corrective actions and extent of condition review for the equipment and human performance issues.

2. Independently evaluate the quality of operator response, and their implementation of procedures, including the hierarchal implementation of Emergency and Abnormal Operating Procedures along with Alarm Response Procedures.

3. Assess the adequacy of maintenance activities, prior to the event, to verify if an adequate assessment of trip potential and risk was conducted prior to the instrument recorder work.

4. Independently evaluate the risk significance of the event.

5. Assess the effectiveness of related training issues.

6. Document the inspection findings and conclusions in a special inspection report in accordance with Inspection Procedure 93812 within 30 days of the exit meeting for the inspection.

ATTACHMENT C

UNIT 2 SEQUENCE OF EVENTS

Unit 2 January 23, 2004 Excess Steam Demand Event

15:26.02	Initial Conditions 100% Reactor Power. 24 CWP secured for planned maintenance. RTCBs 1&5 open due to problems experienced earlier in the day during the performance of an IM STP Reactor Reg System selected to Channel X.
15:26.37	22 SGFP Trips (With direction from the CRS, the CRO attempts multiple resets of the 22 SGFP per plant stabilizing actions IAW AOP-3G. None of the resets are successful and the CRS orders a manual reactor trip when S/G Low Level Pre-Trips are received (coincident with -40" S/G levels per narrow range level indication).)
15:27.48	RPS Steam Generator Low Level Channel A & D Trip. RTCB's 2, 3, 4, 6, 7, 8 open. RPS manual reactor trip from 1C05 due to action of RO.
15:28.20	ADVs and TBVs are not responding as designed as they are still full open and RCS average temperature is well below 557^{o}F.
15:28.26	All pressurizer backup and proportional heater banks automatically secure due to pressurizer level falling below 101". The RO places all heater hand switches in OFF shortly afterwards.
15:28.34	AFAS B actuation. ESFAS SIAS A & B actuation.
15:28.52	2B EDG, 21 & 22 LPSI pumps, 21 & 22 CS pumps, 21 HPSI pump all start.
15:28.53	22 Component cooling pump starts, 23 HPSI pump all start.
15:28.54	21 & 22 Boric acid pumps, 21/22/23 IRU, 24 CAC Fan all start.
15:28.57	ESFAS SGIS A & B Actuation.
15:28.59	Letdown secured. 2A & 2B EDG start.
15:29.00	21 & 22 MSIVs shut (with the MSIVs shut due to the SGIS actuation, the TBVs are no longer contributing to the excess steam demand event. For approximately the next seven minutes the RCS continues to cooldown at a rate of approximately 160oF/hr.
15:29.13	Pressurizer level goes off-scale low.

15:32.15 21B & 22A RCP secured in accordance with RCP Trip Strategy for SIAS actuation.

15:37.00 The Quick Open Dump Signal from RRS is removed from both ADVs when the TBO shifts the hand transfer valves in the 45' switchgear room to align ADV control to 2C43. Over the next 32 minutes, an RCS heatup at approximately 57^{o}F/hr takes place until RCS cold leg temperatures are restored to 515^{o}F.

15:39.50 Pressurizer level returns to scale

15:47.30 The operating crew reduces AFW flow to each S/G from 300gpm to 150gpm.

Summary of EOP-O, Post Trip Immediate Actions:
Safety Function Status
- Reactivity Control - Complete
- Vital Auxiliaries - Complete
- RCS Pressure and Inventory Control - Not Met
- Core and RCS Heat Removal - Not Met
- Containment Environment - Complete
- Rad Levels External to Containment - Complete

Safety System Actuations
- AFAS - Verified
- SIAS - Verified
- SGIS - Verified

15:55.00 EOP-1, Reactor Trip, is implemented from EOP-0. Upon entry, the crew recognizes the high RCS pressure and the rapidly rising pressurizer level and prepares to take stabilizing actions.

15:56.00 The RO takes manual control of the Main Spray Controller, 2HIC100, (which has been greatly reduced due to only having one RCP operating in the spray line loops) and places the output at approximately 30-35% to stop the RCS pressure rise at 2335 psia. Subsequent minor manual Main Spray Controller manipulations results in a stable RCS pressure at around 2318psia. Note - the main spray valves, 1CV100E and 1CV100F, did not start to open until 2300psia (based on a pressurizer controller setpoint of 2250 psia).

15:58.00 Due to the insurge from the RCS heatup, along with approximately 4100 gallons of injection from the Charging system, Pressurizer level has reached ~210" and the Pressurizer temperature has reached a minimum value of 514°F (saturation for 771 psia).

15:59.00 The Pressurizer insurge continues as full Charging is still present at 128 GPM and the 57°F/hr RCS heatup continues. At this point, due to the large volume of "cold" water in the Pressurizer and the lack of full heater capability, RCS pressure begins to rapidly drop from ~2318 to ~1800 psia over the next 22 minutes.

16:01.46 22 & 23 charging pump are secured (H/S placed in PTL).

16:05.00 Based on Operator recall, the Main Spray Controller, 2HIC100, output signal is lowered from 30 – 35% to approximately -2% (although 2HIC100 can be driven to an output as low as -20%, an output of 0% should represent a signal at which both Main Spray valves are full shut).

16:06.50 21 Charging pump is secured.

16:08.00 The RCS heatup is temporarily secured per the operating crew's decision to hold RCS cold leg temperature at 515^{o}F.

16:09.00 Based on Operator recall, both Pressurizer Proportional Heaters are returned to AUTO and Backup Heaters 22 and 24 are placed in ON. Backup Heater 24 only has a capacity of 225 KW (normal capacity is 300 KW) due to a previous CMF that had one bank of heaters removed from service. Backup Heaters 21 and 23 can not be returned to service at this time due to the active SIAS signals.

16:17.28 SIAS A is reset remotely from the Control Room. SIAS B can not be reset from the Control Room due to a problem with the reset pushbutton.

16:27.36 SIAS B is reset locally from the Cable Spreading Room.

16:33.35 21 Charging Pump is started per OI-2A in an effort to restore Letdown to restore Pressurizer level. For approximately the next five minutes, the Operating Crew attempts to restore Letdown, but problems associated with the Control Room position indication for one of the Letdown isolation valves, 2-CV-516, delays the successful restoration.

16:38.50 21 Charging Pump is secured when the Operating Crew believes that the Letdown isolation valve, 2-CV-516, is not opening when attempts are made using the hand switch.

16:39.00 Based on Operator recall, Pressurizer Backup Heaters 21 and 23 are restored and placed in ON now that SIAS has been reset and both heater breakers have been closed locally.

16:45.30 A second heatup of the RCS at approximately 35°F/hr is commenced to return RCS cold leg temperatures to the EOP-1 acceptable range of 525 - 535°F. The heatup and resulting Pressurizer insurge contributes to RCS pressure lowering from ~1800 psia to ~1750 psia over the next 30 minutes. The combination of Letdown and the RCS heatup result in the RCS Pressure lowering to 1750 psia and a second SIAS actuation.

16:48.29 21 Charging pump is started per OI-2A in a second effort to restore Letdown to restore pressurizer level.

16:48.40 Letdown is successfully placed in service and raised to approximately 105gpm over the next nine minutes.

16:57.23 Letdown is maintained between 100 & 115gpm until about 17:14.34.

17:04.00 Per CRS/SM direction, the RO lowers the Main Spray Controller, 2HIC100, output signal to -20% (lowest possible output signal) to ensure that the Main Spray valves are fully closed in an attempt to minimize any leakby on the valves.

17:14.34 Letdown flow is reduced to ~70 GPM as the Operating Crew recognizes that RCS pressure is steadily lowering and re-approaching the SIAS setpoint.

17:18.01 ESFAS SIAS B actuation (lose capability to use pressurizer backup heater 23).

17:18.02 ESFAS SIAS A actuation (lose capability to use pressurizer backup heater 21).

17:20.53 21 charging pump is secured.

17:49.00 After using procedure guidance from EOP-4 and blocking SIAS, the Operating Crew resets SIAS A remotely from the Control Room. The decision to block and reset SIAS is made in order to recover full Pressurizer heater capability in an attempt to restore RCS pressure which has remained between 1750 and 1780 psia for the previous 50 to 60 minutes.

17:53.29 SIAS B is reset locally from the Cable Spreading Room.

17:58.00 Based on Operator recall, Pressurizer Backup Heaters 21 and 23 are restored and placed in ON now that SIAS has again been reset and both heater breakers have been closed locally. The Operating Crew now has full Pressurizer heater output. The Operating Crew decides to not attempt to reinitiate Charging and Letdown until RCS pressure reaches 2100 psia in order to assure that another RCS depressurization does not occur.

18:22.00 Based on Operator recall, the Main Spray Controller, 2HIC100, is returned to automatic control.

18:25.00 SGIS is reset using guidance from EOP-3.

18:29.20 AFAS A & B are reset in accordance with OI-32B.

18:32.29 21 Charging pump is started in preparation for restoring letdown.

18:33.35 Charging and Letdown is restored in attempt to return Pressurizer level to the EOP-1 acceptable band of 130 to 180”. Letdown is established at approximately 45 – 50 GPM.

19:26.00 The Operating Crew exits EOP-1 and implements OP-2 and OP-4.

19:30.00	The 21B and 22A RCPs are restarted in accordance with OI-1A. The 21 AFW pump is secured.
19:50.00	Both MSIVs are reopened in accordance with OP-2.
19:55.00	Secured 21 AFW pump.
20.00.00	RCS parameters have reached normal post-trip levels and are considered steady state.