UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

June 14, 2010

EA-10-080

George H. Gellrich, Vice President
Calvert Cliffs Nuclear Power Plant, LLC
Constellation Energy Nuclear Group, LLC
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657-4702

SUBJECT: CALVERT CLIFFS NUCLEAR POWER PLANT - NRC SPECIAL INSPECTION REPORT 05000317/2010006 AND 05000318/2010006; PRELIMINARY WHITE FINDING

Dear Mr. Gellrich:

On April 30, 2010, the U. S. Nuclear Regulatory Commission (NRC) completed a Special Inspection of the February 18, 2010, dual unit trip at Calvert Cliffs Nuclear Power Plant (CCNPP) Units 1 and 2. The enclosed report documents the inspection results, which were discussed on April 30, 2010, with you and other members of your staff.

The special inspection was conducted in response to the dual unit trip with complications on February 18, 2010. The complications included loss of a 500 kilovolt (kV) offsite power supply to each unit, loss of power to a 4 kV safety bus on each unit, failure of the 2B emergency diesel generator (EDG) to reenergize a 4 kV safety bus, loss of power to the Unit 2 4 kV non-safety buses, loss of Unit 2 forced reactor coolant system (RCS) flow, and loss of the Unit 2 normal heat sink. The NRC's initial evaluation of this event satisfied the criteria in NRC Inspection Manual Chapter 0309, "Reactive Inspection Decision Basis for Reactors," for conducting a special inspection. The Special Inspection Team (SIT) Charter (Attachment 2 of the enclosed report) provides the basis and additional details concerning the scope of the inspection.

The special inspection team (the team) examined activities conducted under your license as they relate to safety and compliance with Commission rules and regulations and with conditions of your license. The team reviewed selected procedures and records, observed activities, conducted in-plant equipment inspections, and interviewed personnel. In particular, the team reviewed event evaluations (including technical analyses), causal investigations, relevant performance history, and extent-of-condition to assess the significance and potential consequences of issues related to the February 18 event.

The team concluded that, overall, station personnel maintained plant safety in response to the reactor trips. Nonetheless, the team identified several issues related to equipment performance and human performance which complicated the event. The enclosed chronology (Attachment 3 of the enclosed report) provides additional details on the sequence of events and event complications.

This report documents one self-revealing finding that, using the reactor safety Significance Determination Process (SDP), has preliminarily been determined to be White, a finding with low to moderate safety significance. The finding is associated with the failure to perform appropriate maintenance activities to ensure 2B EDG reliability. Specifically, safety related time delay relays in the EDG low lube oil pressure trip circuit were used beyond the manufacturer recommended service life, without an associated test or monitoring program to demonstrate their continued reliability. Consequently, when called upon to reenergize the 24 4 kV safety bus, the time delay relay failed and the 2B EDG prematurely tripped in response to a low lube oil pressure signal. The 24 4 kV safety bus was reenergized from an alternate feed source approximately 30 minutes into the event. The significance determination of the event was performed assuming that similar time-delay relays on other systems have not failed due to this performance deficiency. Subsequent corrective actions included replacing and retesting the associated time delay relays on all three EDGs susceptible to the low lube oil pressure trip. There is no current immediate safety concern due to this finding, because all EDGs have subsequently been demonstrated operable and long term corrective actions are being implemented through the Calvert Cliffs corrective action program to address the extent-of-condition and extent-of-cause. The final resolution of this finding will be conveyed in a separate correspondence addressing the final risk significance and disposition of any violations.

As discussed in the attached inspection report, the finding is also an apparent violation (AV) of NRC requirements, involving Technical Specification 5.4.1, and is therefore being considered for escalated enforcement action in accordance with the Enforcement Policy, which can be found on NRC's Web site at http://www.nrc.gov/reading-rom/doc-collections/enforcement/.

In accordance with NRC Inspection Manual Chapter (IMC) 0609, we will complete our evaluation using the best available information and issue our final determination of safety significance within 90 days of the date of this letter. The significance determination process encourages an open dialogue between the NRC staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination.

Before we make a final decision on this matter, we are providing you with an opportunity (1) to attend a Regulatory Conference where you can present to the NRC your perspective on the facts and assumptions the NRC used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of your response to this letter and we encourage you to submit supporting documentation 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. If you decide to submit only a written response, such submittal should be sent to the NRC within 30 days of your receipt of this letter. If you decline to request a Regulatory Conference or submit a written response, you relinquish your right to appeal the final SDP determination, in that by not doing either, you fail to meet the appeal requirements stated in the Prerequisite and Limitation sections of Attachment 2 of IMC 0609. We request that if you decide to attend a Regulatory Conference or provide a written response, that you address the apparent violation, and that you also address the length of time that the 2B EDG was considered inoperable.

Please contact Glenn Dentel at (610) 337-5233 in writing within 10 days from the issue 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. The final resolution of this matter will be conveyed in separate correspondence.

Because the NRC has not made a final determination in this matter, no Notice of Violation is being issued for these inspection findings at this time. In addition, please be advised that the number and characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

In addition, the report documents two NRC-identified findings and two self-revealing findings, each of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at Calvert Cliffs Nuclear Power Plant. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Senior Resident Inspector at Calvert Cliffs Nuclear Power Plant. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

David C. Lew, Director for
Division of Reactor Projects

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

Enclosure: Inspection Report 05000317/2010006 and 05000318/2010006
w/Attachments: Supplemental Information (Attachment 1)
Special Inspection Team Charter (Attachment 2)
Detailed Sequence of Events (Attachment 3)

cc w/encl: Distribution via ListServ

Enclosure: Inspection Report 05000317/2010006 and 05000318/2010006

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/RA/
David C. Lew, Director
Division of Reactor Projects

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cc w/encl: Distribution via ListServ
Distribution w/encl (see attached page)
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U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.:	50-317 50-318
License No.:	DPR-53, DPR-69
Report No.:	05000317/2010006, 05000318/2010006
Licensee:	Constellation Generation Company
Facility:	Calvert Cliffs Nuclear Power Plant (CC)
Location:	Lusby, Maryland
Dates:	February 22, through April 30, 2010
Team Leader:	D. Kern, Senior Resident Inspector, Division of Reactor Projects (DRP)
Team:	W. Cook, Senior Reactor Analyst, Division of Reactor Safety (DRS) M. Patel, Reactor Inspector, DRS P. Presby, Reactor Inspector, DRS B. Smith, Resident Inspector, DRP R. Montgomery, Reactor Engineer, Nuclear Safety Professional Development Program, DRP (added subsequent to issuance of the Inspection Charter)
Observers:	S. Gray, Power Plant Research Program Manager, Department of Natural Resources, State of Maryland M. Griffen, Nuclear Emergency Preparedness Coordinator, Department of the Environment, State of Maryland
Approved By:	Glenn T. Dentel, Chief Projects Branch 1 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000317/2010006 and 05000318/2010006; 02/22/2010 - 04/30/2010; Constellation Generation Company, Calvert Cliffs Nuclear Power Plant; Special Inspection for the February 18, 2010, Dual Unit Trip; Inspection Procedure 93812, Special Inspection.

A six-person NRC team, comprised of resident inspectors, regional inspectors, and a regional senior reactor analyst conducted this Special Inspection. The team was accompanied by two engineers from the State of Maryland, Department of Natural Resources and Department of the Environment. One apparent violation with potential for greater than Green safety significance and four Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, 'Significance Determination Process' (SDP); the crosscutting aspect was determined using IMC 0310, 'Components Within the Cross Cutting Areas;' and findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

NRC Identified and Self Revealing Findings

Cornerstone: Initiating Events

- **Green:** A self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Actions," was identified, because auxiliary building roof leakage into the Unit 1 and Unit 2 45 foot switchgear rooms was identified on several occasions from 2002 to 2009, but was not thoroughly evaluated and corrective actions to this condition adverse to quality were untimely and ineffective. This degraded condition led to the failure of the auxiliary building to provide protection to several safety related systems from external events, a ground on a reactor coolant pump (RCP) bus, and ultimately a Unit 1 reactor trip. Immediate corrective actions included: repair of degraded areas of the roof; walk downs of other buildings within the protected area that could be susceptible to damage to electrical equipment due to water intrusion; issuance of standing orders to include guidance regarding prioritizing work orders due to roof leakage; and identifying further actions to take during periods of snow or rain to ensure plant equipment is not affected. Constellation entered the issue into their corrective action program (Condition Report (CR) 2010-001351). Long-term corrective actions include implementation of improved plant processes for categorization, prioritization and management of roofing issues.

  The finding is more than minor because it is associated with the protection against external factors attribute of the Initiating Events Cornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The team determined the finding had a very low safety significance because, although it caused the reactor trip, it did not contribute to the likelihood that mitigation equipment or functions will not be available. The cause of the finding is related to the crosscutting area of Problem Identification and Resolution, Corrective Action Program aspect P.1(c) because Constellation did not thoroughly evaluate the problems related to the water intrusion into the auxiliary building

such that the resolutions addressed the causes and extent-of-condition. This includes properly classifying, prioritizing, and evaluating the condition adverse to quality. (Section 2.1)

- **Green:** The team identified a finding for failure to translate the design calculations of phase overcurrent relays on 13 kV feeder breakers into the actual relay settings. The overcurrent relays protect the unit service transformer against faults in the primary or secondary side windings. The design specified limit of 1200 amps was determined based on the breaker rating of the feeder breakers. Constellation determined the as-found relay setting for the feeder breakers was 1440 amps which exceeded the rating of the feeder breakers. The team determined that due to the as-found relay setting, certain phase overcurrent conditions could potentially cause the breakers to fail prior to the phase overcurrent relay sensing the degraded condition. This condition could affect the recovery of the safety buses from the electrical grid. Constellation entered this issue into the corrective action program (condition report 2010-002123).

  The finding is more than minor because it affected the Initiating Events Cornerstone attribute of equipment performance for ensuring the availability and reliability of systems to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Also, this issue was similar to Example 3j of IMC 0612, Appendix E, "Examples of Minor Issues," because the condition resulted in reasonable doubt of the operability of the component, and additional analysis was necessary to verify operability. This finding was determined to be of very low safety significance because the design deficiency did not result in an actual loss of function based on Constellation's determination that the maximum load current possible would not challenge the feeder breaker ratings. Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. The finding did not have a cross-cutting aspect because the most significant contributor to the performance deficiency was not reflective of current licensee performance. (Section 2.3)

Cornerstone: Mitigating Systems

Preliminary White: The NRC identified an apparent violation of Technical Specification 5.4.1 for the failure of Constellation to establish, implement, and maintain preventive maintenance requirements associated with safety related relays. The team identified that Constellation did not implement a performance monitoring program specified by the licensee in Engineering Service Package (ES200100067) in lieu of a previously established (in 1987) 10-year service life replacement PM requirement for the 2B EDG T3A time delay relay. As a consequence, the 2B EDG failed to run following a demand start signal on February 18, 2010. Following identification of the failed T3A relay, it was replaced and the 2B EDG was satisfactorily tested and returned to service. In addition, time delay relays used in the 1B and 2A EDG protective circuits, that also exceeded the vendor recommended 10-year service life, were replaced. Constellation entered this issue, including the evaluation of extent-of-condition, into the corrective action program.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely impacted the objective of ensuring the availability, reliability, and capability of the safety related 2B EDG to

respond to a loss of normal electrical power to its associated safety bus. This finding was assessed using IMC 0609, Appendix A and preliminarily determined to be White (low to moderate safety significance) based upon a Phase 3 Risk Analysis with an exposure time of 323 days which resulted in a total (internal and external contributions) calculated conditional core damage frequency (CCDF) of 7.1E-6. The cause of this finding is related to the crosscutting area of Human Performance, Resources aspect H.2(a) because preventive maintenance procedures for the EDGs were not properly established and implemented to maintain long term plant safety by maintenance of design margins and minimization of long standing equipment issues. (Section 2.2)

- **Green**: The team identified a NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," because Constellation did not thoroughly evaluate and correct a degraded condition of a CO-8 relay disc sticking or binding issues which can adversely impact the function of the EDGs and the electrical distribution protection scheme. Specifically, following the February 18, 2010 event, Constellation did not identify and adequately evaluate the recent CO-8 relay failures due to sticking or binding of the induction discs in the safety related and non-safety related applications. Constellation entered this issue into the corrective action program (CR 20100004673).

  The finding is more than minor because it is associated with the equipment reliability attribute of the Mitigating Systems Cornerstone, and it adversely affected the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). This finding was determined to be of very low safety significance because these historical relay failures did not result in an actual loss of system safety function. The cause of the finding is related to the crosscutting area of Problem Identification and Resolution, Corrective Action Program aspect P.1(c) because Constellation did not thoroughly evaluate the previous station operating experience of CO-8 relay induction disc sticking and binding issues such that resolutions addressed the causes and extent-of-condition. (Section 2.3)

- **Green**: A self-revealing NCV of Technical Specification (TS) 5.4.1.a, "Procedures" was identified for failure to establish adequate procedures for restoration of Chemical and Volume Control System (CVCS) letdown flow. On February 18, 2010, an electrical ground fault caused a Unit 1 reactor trip, loss of the 500 kV Red Bus, and CVCS letdown isolation as expected on the ensuing instrument bus 1Y10 electrical transient. Deficient operating instructions prevented timely restoration of letdown flow following the initial transient. Pressurizer level remained above the range specified in Emergency Operating Procedure (EOP)-1 for an extended period because of the operators' inability to restore letdown. This ultimately led to exceeding the TS high limit for pressurizer level. CVCS Operating Instruction OI-2A was subsequently revised, providing necessary guidance for re-opening the letdown system excess flow check valve to restore letdown flow. This event was entered into the licensee's corrective action program (CR 2010-001378).

  The finding is more than minor because it is associated with the procedure quality attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding is of very low safety significance because it is not a design or qualification deficiency, did not represent a loss of a safety function of a system or a single train greater than its TS

allowed outage time, and did not screen as potentially risk significant due to external events. This finding has a crosscutting aspect in the area of human performance, resources aspect H.2(c), because Constellation did not ensure that procedures for restoring CVCS letdown were complete and accurate. (Section 3.1)

REPORT DETAILS

1. Background and Description of Events

In accordance with the Special Inspection Team (SIT) charter (Attachment 2), team members (the team) conducted a detailed review of the February 18, 2010, dual unit trip with complications at Calvert Cliffs Nuclear Power Plant including equipment and operator response. The team gathered information from the plant process computer (PPC) alarm printouts, interviewed station personnel, performed physical walkdowns of plant equipment, and reviewed procedures, maintenance records, and various technical documents to develop a detailed timeline of the event (Attachment 3). The following represents an abbreviated summary of the significant automatic plant and operator responses which began at 8:24 a.m. on February 18, 2010, and ended on February 22, 2010, with both Unit 1 and Unit 2 in cold shutdown:

On February 18, 2010, at 8:24 a.m., the Unit 1 reactor automatically tripped from 93 percent reactor power in response to a reactor coolant system (RCS) low flow condition. Water had leaked through the auxiliary building roof into the 45' elevation switchgear room, causing an electrical ground on bus 14 which tripped the 12B reactor coolant pump (RCP), thereby initiating the reactor protection system trip on RCS low flow. Three of the four Unit 1 RCPs continued operating.

Ground overcurrent (O/C) relay 2RY251G/B-22-2 failed to actuate as designed, permitting the Unit 1 ground O/C condition to reach the Unit 2 22 13 kV RCP bus and the associated 500 kV/13 kV transformer (P-13000-2). Ground O/C protection for the P-13000-2 transformer actuated which deenergized the 500 kV "Red Bus" offsite power supply, the 22 bus, and all four RCPs. At 8:24 a.m., the Unit 2 reactor automatically tripped from full reactor power in response to the associated reactor protection system trip on RCS low flow.

The P-13000-2 isolation also deenergized the 21 13 kV service bus, which deenergized the Unit 1 14 4 kV safety bus, the Unit 2 24 4 kV safety bus, and several Unit 2 non-safety related 4 kV busses. The 1B emergency diesel generator (EDG) started as designed and reenergized the Unit 1 14 bus. The 2B EDG started, but tripped 15 seconds later due to a low lube oil pressure signal and the 24 bus remained deenergized. The electrical transient deenergized 120 volt instrument buses 1Y10 and 2Y10, which isolated the chemical volume control system (CVCS) and RCS letdown for both units and complicated operators' control of pressurizer level.

Loss of power to the Unit 2 non-safety related buses resulted in loss of the normal RCS heat removal path (main feedwater pumps, circulating water pumps, and condenser). Operators used the turbine driven auxiliary feedwater pump and atmospheric steam dump valves for decay heat removal.

At 8:48 a.m., Unit 2 operators exited emergency operating procedure (EOP)-0, "Reactor Trip" and entered EOP-2, "Loss of Flow and Loss of Offsite Power." At 8:57 a.m., operators reenergized the 24 bus via the alternate feeder breaker. At 9:00 a.m., Unit 2 operators restored RCS letdown and maintained appropriate pressurizer level control.

At 11:17 a.m., Unit 2 operators started the 23 motor driven auxiliary feedwater (AFW) pump and secured the turbine driven AFW pump. At 11:18 a.m., Unit 2 operators exited

the EOPs and returned to normal operating procedures. As of 12:02 p.m., Unit 1 operators remained unsuccessful at restoring RCS letdown and exceeded the pressurizer high level limits specified by both EOPs and TS. At 1:09 p.m., Unit 1 operators restored RCS letdown and restored normal pressurizer level control. At 1:38 p.m., Unit 1 operators exited the EOPs and returned to normal operating procedures.

At 2:07 p.m., Unit 1 vital 4 kV bus 14 was aligned to its alternate offsite source and the 1B EDG was secured. At 5:13 p.m., Unit 2 operators started 21B and 22A RCPs to restore forced RCS circulation. On February 19, 2010, at 12:05 p.m., operators verified two offsite power supplies were available, with the 21 13 kV service bus energized from an alternate offsite source. On February 20, 2010, at 10:31 p.m. repairs on the 2B EDG were completed and the diesel generator was declared operable.

Unit 1 achieved cold shutdown at 5:38 a.m. on February 21, 2010, and 500 kV Red Bus was restored at 5:50 a.m. Unit 2 achieved cold shutdown at 5:00 a.m. on February 22, 2010.

2. Equipment Performance

2.1 Untimely Corrective Actions to Unit 1 45 Foot Elevation Switchgear Room Roof Leak Caused Reactor Trip

a. Inspection Scope

Water leakage through the Unit 1 auxiliary building roof into the 45' elevation switchgear room, caused an electrical ground on Bus 14 which tripped the 12B RCP, thereby initiating a reactor protection system trip on RCS low flow. The team interviewed station personnel, performed field walkdowns, and reviewed various records including maintenance backlogs, maintenance history, operating logs, condition reports, and maintenance rule program records to independently determine the cause of the event and assess associated corrective actions. Constellation determined the root cause of the event was that Calvert Cliffs lacked sensitivity to the consequences associated with degraded roof conditions which led to a reactive rather than preventive strategy for dealing with roof leaks. The team independently reviewed Constellation's Root Cause Analysis Report (RCAR) for the Unit 1 reactor trip to determine the adequacy of the evaluation, the extent-of-condition review, and associated corrective actions.

b. Findings

Introduction: A self-revealing non-cited violation (NCV) of very low safety significance associated with 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Actions," was identified because Constellation did not promptly identify and correct degraded conditions associated with the Unit 1 auxiliary building (45-foot elevation switchgear room) roof leakage. These degraded conditions led to the failure of the auxiliary building to provide adequate protection to numerous safety related systems from external events (adverse weather conditions) resulting in a ground on a reactor coolant pump (RCP) bus and a consequential Unit 1 reactor trip on February 18, 2010.

Description: On February 18, 2010, Unit 1 tripped due to water from a roof leak entering into the Unit 1 45-foot elevation switchgear (SWGR) room and causing a phase to ground short near a current transformer (CT) for the 12B RCP bus 14P

differential/ground current protection devices. The ground fault was not isolated close to the source, due to a failed ground protection relay in the feeder breaker to the Unit 1 RCP bus. The consequential trip of the 12B RCP led to the Unit 1 reactor protection system (RPS) trip due to the a low reactor coolant system (RCS) flow signal.

While conducting a review of the dual unit trip, the team noted that in July of 2008, condition report (CR) IRE-032-766 was written regarding rain water which had fallen onto and into the emergency shutdown panel (ESDP) 1C43, which is located in the Unit 1 45' elevation SWGR room. Immediate actions were taken to notify the control room supervisor of the condition as well as to clean up the pooled water around the panel. Corrective actions were initiated to establish a program to maintain weather tight building integrity. In June of 2009, CR 2009-004060 documented water dripping inside the SWGR room just east of the No. 12 motor generator set. No immediate actions were taken; however, recommended actions were to repair the roof. On August 8, 2009, a third CR (CR 2009-005508) was written, again regarding water leaking into the SWGR room and onto the ESDP. Immediate actions were taken to cover the panel with herculite and to direct the leaking water into a plastic bucket, as well as mopping up the standing water. Despite the immediate actions taken to address the three rain water issues, no additional actions were taken to properly prioritize, identify, and correct the roof leakage. This is evident due to the fact that each CR was given the lowest priority (category 4) as well as none of the work orders written to address the roof leakage had been approved. Additional safety related SWGR equipment in the SWGR room included power supply breakers for the "B" train auxiliary feed water pump, high pressure safety injection pump, low pressure safety injection pump and EDG.

Based on the review of the RCAR, the team noted several missed opportunities from 2002 to 2009 to identify and evaluate the degraded condition prior to the dual unit trip. During a periodic bus inspection in 2004, repairs were made to insulating material on the power cables inside the 14P01 cubicle to correct a water spot on the "B" phase of the 12B RCP bus. This cubicle is in the same SWGR enclosure as the 14P02 cubicle where the water intrusion occurred that resulted in the February 18, 2010 trip. The work was completed under the bus inspection work order; however, no CR was written documenting the indicated water intrusion. This preventive maintenance activity should have led to an investigation into the cause of the water intrusion as well as the extent of the degraded condition. An apparent cause (IRE-007-705) was also completed in 2005 in response to a CR written by quality assurance personnel noting that there were 33 leaks identified during a walk down but no trend CR was written. Corrective actions were proposed; however they were not adequately implemented.

The Calvert Cliffs' maintenance rule scoping document states that the function of the auxiliary building is to provide structural support and separation to safety and non-safety related equipment while accounting for the effects of certain external events. Rain storms and heavy snowfall are examples of external events for which the auxiliary building is designed to provide protection against. The Calvert Cliffs' structure monitoring program did not effectively use the corrective action process to ensure this function of the auxiliary building would be maintained. At the time of this special inspection, 58 work orders were open to repair roof leaks. None of these work orders were planned or scheduled. Several of these work orders were over 2 years old.

Immediate corrective actions included: repairing degraded areas of the auxiliary building roof; performing walk downs of other protected area buildings that could be susceptible

to damage to electrical equipment due to water intrusion; issuing standing orders to include guidance regarding prioritizing work orders due to roof leakage; and identifying further actions to take during periods of snow or rain to ensure plant equipment is not affected. Long-term corrective actions include implementing improved plant processes for categorization, prioritization, and management of degraded roof and water leakage issues.

The team concluded that Constellation had numerous opportunities to have thoroughly evaluated, classified, and prioritized the roof leakage, such that corrective actions could have addressed the full extent of the auxiliary building roofing degraded condition and prevented the water intrusion event and subsequent plant trip on February 18, 2010. The team concluded that station personnel did not properly inspect and maintain the roofs of several safety related structures to ensure the internal safety related and non-safety related components were protected from effects of the external environment (i.e., rain, snow).

Analysis: The failure of Constellation to promptly identify and correct conditions adverse to quality, associated with the auxiliary building roof leakage, is a performance deficiency. The finding is more than minor because it is associated with the Initiating Events Cornerstone and affects the cornerstone objective to limit the likelihood of those external events that upset plant stability and challenge critical safety functions during shutdown, as well as power operations. The inspectors evaluated this finding using IMC 0612 Attachment 4, "Phase 1- Initial Screening and Characterization of Findings." The team determined the finding to have very low safety significance because, although it contributed to a reactor trip, it did not contribute to the likelihood that mitigation equipment would not be available.

The cause of this finding is related to the Problem Identification and Resolution cross-cutting area, corrective action program, because Constellation did not thoroughly evaluate the problems related to the water intrusion into the auxiliary building such that the resolutions addressed the causes and extent-of-condition. This included properly classifying, prioritizing, and evaluating the condition adverse to quality (P.1(c)).

Enforcement: 10 CFR Part 50, Appendix B, Criterion XVI "Corrective Action," states, in part, that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, from 2002 to February 18, 2010, Constellation did not thoroughly evaluate and promptly correct degraded conditions associated with auxiliary building roof leakage. This led to the failure of the auxiliary building to provide protection to several safety related systems from external events (i.e. flooding), a ground on a reactor coolant pump bus, and ultimately a Unit 1 reactor trip. Because this violation was of very low safety significance and was entered into the licensee's corrective action program as CR 2010-001351, this violation is being treated as an NCV, consistent with the NRC Enforcement Policy." **(NCV 0500317/318/2010006-01: Failure to Thoroughly Evaluate and Correct Degraded Conditions Associated with Auxiliary Building Roof Leakage)**

2.2 Deficient Preventive Maintenance Program Procedures and Implementation for EDG Agastat Time Delay (TD) Relays

a. Inspection Scope

On February 18, 2010, Unit 2 experienced an automatic reactor trip, loss of the P-13000-2 Service Transformer, and loss of the 500 kV Red Switchyard Bus. The loss of the Red Bus resulted in loss of power to the No. 24 4 kV safety bus which caused an automatic start of the 2B EDG. The 2B EDG tripped due to low lube oil (LO) pressure after running for 15.2 seconds. The team reviewed the timing sequence, design requirements, relay schematics, and surveillance and maintenance history for the 2B EDG. Failure of a T3A time delay (TD) relay coincident with the 2B EDG LO low pressure protection logic not having reset caused the low LO pressure protective trip of the engine. Constellation identified two root causes for the EDG failure: (1) station personnel failed to recognize and quantify the low margin in all aspects of the low lube oil pressure trip set feature for the EDG; and, (2) station personnel did not rigorously assess all failure modes of the Agastat relays in the EDG protection circuitry prior to extending its service life beyond the vendor qualified life.

The team reviewed Constellation's evaluation of the 2B EDG's failure, the adequacy of proposed and completed corrective actions, and the appropriateness of the extent-of-condition review. Independent reviews of design documents, mock-up testing, drawings, surveillance testing, and field walk-downs were performed by the team to evaluate the cause of the 2B EDG failure. In addition, the team reviewed Constellation's preventive maintenance (PM) history and associated PM programs.

b. Findings

Introduction. The NRC identified an apparent violation of Technical Specification 5.4.1 for the failure of Constellation to establish, implement, and maintain preventive maintenance requirements associated with safety related relays. The team identified that Constellation did not implement a performance monitoring program in lieu of a previously established 10-year service life replacement PM requirement for the 2B EDG T3A TD relay. As a consequence, the 2B EDG failed to run following a demand start signal on February 18, 2010. This apparent violation is preliminarily determined to be of low-to-moderate safety significance (White).

Description. The purpose of the T3A (Agastat 7000 series) TD relay in the EDG protective circuit is to bypass the low lube oil trip on the EDG start to allow the EDG lube oil pressure to initially build up to operating conditions. The relay begins timing when the EDG speed reaches 810 rpm (approximately 6 seconds after EDG start). The relay functions to bypass the low LO pressure trip (<17 pounds pressure sensed in the EDG upper crankcase) for 15 seconds (a total of 21 seconds from EDG start). This time delay allows LO pressure to build-up in the EDG upper crankcase high enough to reset the trip logic (2 of 3 pressure switches reset at >20 pounds). The Unit 2 February 18, 2010, sequence of events printout revealed that the T3A relay timed out early (after 9.2 seconds) at 15.2 seconds following the EDG start and prior to the low LO pressure sensing trip logic being reset. Constellation determined that a typical fast, non-pre-lubricated EDG start results in LO pressure exceeding 20 pounds pressure approximately 13 seconds following the start of the EDG. Accordingly, the early timeout

of the T3A relay was not the only degraded 2B EDG condition that presented itself on February 18, 2010. Constellation attributed the February 18 delayed reset of the pressure switches to "sticky lubrication oil" in the ½-inch stainless steel pressure sensing line to the pressure switches, vice an actual low LO pressure condition in the diesel engine upper crankcase.

The team determined that the T3A relay, which timed-out early, had been in-service on the 2B EDG for approximately 13.5 years, 3.5 years beyond its vendor recommended 10-year service life. In 2001, Constellation engineering discontinued the vendor recommended 10-year replacement PM and substituted a performance monitoring program envisioned to ensure Agastat relays (approximately 100 safety related applications and 500 to 600 non-safety related applications in the two Calvert Cliffs units) were appropriately monitored and replaced prior to failure (reference Engineering Service Package ESP No. ES200100067, approved 03/06/2001). The team identified that a relay performance monitoring program had not been established since 2001 at Calvert Cliffs. Constellation initiated CR 2010-04493 to address this performance issue. The Shift Manager reviewed the immediate operability and determined that the other safety-related components using Agastat relays remain operable because these relays are installed in less harsh operational environments (e.g. vibrations) then the EDG Agastat relays, and therefore, are less susceptible to age-related degradation. In addition, CR 2010-01784 was written to address the extent-of-condition of Agastat relays used in other safety-related applications.

Constellation replaced the 2B EDG failed T3A relay and, via a single 'as-found' bench test, validated its February 18, 2010, in-service failure, when the relay failed again, timing out early at 11.6 seconds. Subsequent attempts by Constellation to adjust the relay to within calibration tolerance were unsuccessful. The failed relay was shipped to an independent laboratory for diagnostic testing and destructive examination. The laboratory identified that, exercised over its full range of operation, >40 percent of the TD actuation results were out of tolerance. Internals examination identified three of six screws on the flexible diaphragm retaining ring were loose, suggesting that the early time-out of the relay was possibly due to excessive air bleed off (leakage passed the diaphragm seal). Constellation concluded that the TD relay failure was a relatively recent event (within the last 47 days) and attributable to the three 2B EDG starts and approximately seven cumulative hours of operation that occurred in early January 2010. The team concluded that Constellation provided no evidence to support the approximate time of failure of the TD relay. However, the team determined that the failure and probable failure mechanism may have occurred between the last successful calibration of the TD relay (May 13, 2008) and the observed failure on February 18, 2010. In addition, the team concluded that the TD relay early time-out was most likely a latent failure and masked by the monthly EDG surveillance test. Accordingly, the TD relay failure was revealed by the fast, non-pre-lubrication, demand start on February 18, 2010.

The basis for the team's conclusion was as follows:

- Constellation's troubleshooting results were not conclusive regarding the lubricating oil pressure sensing line "sticky oil" theory, based upon the following: 1) the "sticky oil" drained from the sensing line was not saved or analyzed for consistency or contaminants (Constellation did not exercise appropriate quarantine practices); 2) the ½-inch LO pressure sensing line was not backfilled with oil and was therefore susceptible to trapped air pockets that may tend to dampen accurate pressure

sensing and may result in a delayed pressure response; and, 3) Constellation's routine (two-year calibration cycle) and post-event calibration checks of the pressure switches did not record "as-found" values of the pressure switch reset values; this information may have assisted in ruling out possible pressure switch setpoint drift or malfunction.

The team acknowledged that Constellation's subsequent mock-up testing of the pressure sensing line did show that lubricating oils of heavier viscosity tend to delay the pressure sensing response. However, the 100W oil used to demonstrate the phenomena (approximate 3 second pressure sensing delay) was considerably heavier than the lubricating oil used in the 2B EDG (40W) and may or may not have reflected the "sticky oil" viscosity observed by the technician responsible for the pressure switch troubleshooting.

- The fast, non-pre-lube start of the 2B EDG contributed to the identification of the failed relay; whereas the monthly pre-lube EDG starts likely masked the failure of the TD relay. The team determined that for a typical fast, pre-lubricated EDG start, a small pre-lube pump is run for 3 to 5 minutes prior to the EDG starting and fills the upper crankcase with lubricating oil, but is not of sufficient capacity to pressurize the upper crankcase. When the EDG starts, the engine driven LO pump functions to complete the upper crankcase fill and pressurization (>20 pounds pressure) in approximately 8 seconds. Accordingly, any relay failure (timing out early, <12 seconds) is masked by the fast, pre-lube EDG start because the relay actuates at 6 seconds and only has to satisfactorily function (block the low lube oil trip signal) for >2 seconds. The team noted that by the low LO pressure protective system design, the fast pre-lube EDG starts allow for a significant margin to satisfactory build-up of lube oil pressure before the TD relay times out (a margin of approximately 13 seconds). For the fast non-pre-lube start, LO pressure typically exceeds 20 pounds pressure at 13 seconds after EDG start. This 13 second time interval similarly translates to the TD relay having to function for >7 seconds from the time it actuates at 6 seconds from EDG start. This 7 seconds minimal TD function also, by design, provides margin (an additional 8 seconds) for satisfactory LO pressure build-up.

The team concluded that the last known satisfactory relay calibration (setpoint) check of the T3A relay was the two-year calibration check completed on May 13, 2008. Based upon Constellation records, the as-found setting was 17.5 seconds and the as-left was 16.5 seconds. All monthly surveillance tests of the 2B EDG since May 13, 2008, were fast, pre-lube starts. There were no demand starts of the 2B EDG between May 13, 2008, and February 18, 2010, that would have proved or disproved that the T3A relay was operable, and that the LO pressure sensing line issue was coincidental or precipitous of a fast, non-pre-lube start.

Following identification of the failed T3A relay, the licensee replaced the relay, satisfactorily tested the 2B EDG, and returned the 2B EDG to service. In addition, time delay relays used in the 1B and 2A EDG protective circuits, that also exceeded the vendor recommended 10-year service life, were replaced. Constellation is evaluating the continued use of Agastat relays beyond their vendor recommended 10-yr service life. As previously noted, there are approximately 100 safety related applications and 500-600 non-safety related applications at the two Calvert Cliffs units.

Analysis. The team identified that the failure of Constellation to perform preventive maintenance in accordance with vendor recommendations without adequate performance monitoring on safety related Agastat 7000 series TD relays used in safety related applications is a performance deficiency and violation of Technical Specifications (TS). This violation of TS is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems Cornerstone and adversely impacted the objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the early timeout of the T3A relay caused the 2B EDG to trip prior to the low lube oil pressure trip signal clearing (resetting) after a demand fast start on February 18, 2010. The failure of the 2B EDG to run resulted in the continued loss of alternating current to the No. 24 4 kV safeguards bus and its associated emergency core cooling systems.

In accordance with Table 4a of IMC 0609, Attachment 04, "Phase 1 – Initial Screening and Characterization of Findings," this performance deficiency required a Phase 2 or 3 risk analysis because the issue resulted in an actual loss of safety function of a single train for greater than its TS allowed outage time. A Phase 3 risk assessment was performed by a Region I Senior Reactor Analyst (SRA) using the SAPHIRE software and Calvert Cliffs Unit 2 Standardized Plant Analysis Risk (SPAR) model, Revision 3.46, dated February 2010.

To conduct the Phase 3 analysis, the SRA made the following modeling assumptions:

- Exposure time was based upon a T/2 approximation. The team determined that the 2B EDG exposure time is best approximated by a T/2 value, per the usage rules of IMC 0308, Appendix A, "Technical Basis for At Power Significance Determination Process." Specifically, if the inception of a condition is unknown, the use of the mean exposure time (T/2) is a statistically valid time period because it represents one-half of the time since the last successful demonstration of the component's function and the time of discovery or known failure. The last successful demonstration of the T3A relay was the calibration check performed on May 13, 2008. The total time (T) between May 13, 2008 and February 18, 2010 is 646 days. Therefore, T/2 represents an approximate exposure time of 323 days or 7752 hours.

- SPAR model basic event EPS-DGN-FS-2B, representing "Diesel Generator 2B Failure to Start" was set to TRUE. The basis for the TRUE, vice a failure probability of 1.0, is that common cause failure of the remaining Fairbanks-Morris EDGs could not be conclusively ruled out. The same type Agastat 7000 series TD relays, with comparable greater than 10 years in-service times were installed on the 1B and 2A EDGs.

- SPAR model basic event AFW-XHE-XM-FC8, representing operator failure to open the Turbine Building to turbine driven auxiliary feedwater (TDAFW) pump room door within 12 hours of a station blackout event, was set to FALSE. The basis for this change is that recent engineering analysis of the TDAFW pump room heat-up (post Appendix R fire, LOOP/LOCA, SBO) identified no dependency on operator action to open the door to the turbine building to ensure adequate cooling of the TDAFW pumps.

- No additional 2B EDG recovery credit was applied to the model based upon this event. The SRA noted that 2B EDG non-recovery probability (0.772) in the SPAR model is based upon industry statistical data. The SRA notes that Constellation procedures have operators align the OC EDG (within 45 minutes) vice attempt to troubleshoot and restart the failed EDG. Accordingly, any subsequent attempts to restart the 2B EDG, after an approximate one hour delay (aligning the OC EDG) would likely have the same result because all LO would have drained from the upper crankcase.

- Even though Agastat 7000 series relays are used in multiple safety related applications (some beyond their vendor recommended service life), no broad-based increase in safety related systems' or components' failure probabilities was applied for this Phase 3 risk assessment. As a consequence, the calculated risk estimate for this condition may be a non-conservative value because the Agastat relays are used in multiple other safety related applications beyond the manufacturer's recommended 10-year service life.

- Truncation for the SPAR model analysis was set at 1E-13.

Using the above stated assumptions, the increase in internal risk (core damage frequency) associated with the 2B EDG failure of February 18, 2010, was estimated at 6.0E-6. The dominant core damage sequence involves the loss of Facility B (13 kV Service Bus No. 21), loss of steam generator cooling (main feedwater and auxiliary feedwater), and the subsequent loss of once through cooling (feed and bleed, using the charging system and a power operated relief valve).

Based upon the absence of an NRC external risk quantification tool, the SRA used Constellation's calculated external risk values to approximate the external risk contribution. Constellation's estimated external risk is based upon a RISKMAN fire modeling tool and was calculated at 1.1E-6 for the T/2 exposure period. No appreciable external risk contributions were identified for flooding or seismic events. The dominant core damage external events include turbine building fires (involving the steam generator main feedwater pump area) and high wind/hurricane events. The dominant turbine building fire scenarios involve the failure of the available EDGs (2B and 1B) and a spurious initiation of the safety feature actuation system (SFAS). The dominant high wind/hurricane event core damage scenarios involve the assumed failure of the OC EDG, the subsequent failure of the remaining safety related EDGs, and a spurious SFAS.

Based upon the SRA's calculated internal events risk estimate and Constellation's estimated external events risk contribution, the total increase in Unit 2 core damage frequency for this finding is approximately 7.1E-6. Accordingly, this finding is of low to moderated safety significance (WHITE). This finding and the associated risk analysis was reviewed by a Significance and Enforcement Review Panel (SERP) conducted on June 1, 2010. The SERP concluded that the stated Technical Specification violation and associated risk characterization were appropriate. The violation does not represent an immediate safety concern because the licensee took prompt corrective actions to replace the Agastat relays in use beyond their service life for all three Fairbanks-Morris EDGs and ensured the LO pressure sensing lines were properly backfilled. Subsequent testing of all three EDGS verified operability, including a non-pre-lubricated fast start of the 2B EDG.

The Constellation PRA staff performed a risk assessment of the 2B EDG failure using their CAFTA internal events model and RISKMAN external events model. Constellation assumed the same exposure time as the Region I SRA of T/2 equal to 323 days. Constellation's total risk estimate was 3.1E-6 CDF. Based upon discussions with the Constellation PRA staff, their risk estimate and dominant core damage sequences compare favorably with the NRC results.

The cause of this finding is related to the crosscutting area of Human Performance, resources aspect because preventive maintenance procedures for the EDGs were not properly established and implemented to maintain long term plant safety by maintenance of design margins and minimization of long standing equipment issues (H.2(a)).

Enforcement. Technical Specification 5.4.1 states, in part, that written procedures specified in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, shall be established, implemented, and maintained. Section 9.b. of Appendix A to Regulatory Guide 1.33 states, in part, that preventive maintenance schedules should be developed to specify replacement of parts that have a specific service life. In March 2001 Constellation replaced their original 10-year relay replacement preventive maintenance with a proposed performance monitoring program, to ensure the continued reliability and operability of Agastat relays installed in safety related applications beyond the vendor recommended 10-year service life, via Engineering Change Package No. ES200100067.

Contrary to the above, the team identified that Constellation did not establish a performance monitoring program, and all Agastat relays installed in safety related applications at Calvert Cliffs have been subject to "run to failure" preventive maintenance/replacement interval. Constellation took prompt corrective action to replace Agastat relays used in service, beyond their 10-year service life, in the 2B, 2A and 1B EDGs. The remaining Agastat relays, used in safety related applications beyond their vendor recommended service life, are under evaluation by Constellation. Constellation has initiated several CRs (see Attachment 1 to this report) associated with this performance deficiency. Pending final significance determination, the finding is identified as **Apparent Violation (AV) 05000318/2010006-02, Inadequate Preventive Maintenance Results in the Failure of the 2B Emergency Diesel Generator.**

2.3 Ground Fault Relay 251G/B-22-2 Did Not Actuate on Ground Overcurrent to Trip Open Breaker 252-2202

a. Inspection Scope

The team reviewed design requirements, drawings, and maintenance history of the 251G/B-22-2 relay. Failure of this relay to actuate and trip open the 252-2202 breaker resulted in a loss of the P-13000-2 service transformer, which resulted in loss of power to the Unit 2 RCPs and a Unit 2 trip with loss of normal decay heat removal. Unit 2 remained on atmospheric dump valves and auxiliary feedwater for heat removal for approximately 68 hours. Constellation determined the most likely cause of the relay failure was premature coil aging due to the operating environment and the magnitude of the current seen, which caused insulation breakdown and shorting of the magnetizing coil. Even though Constellation could not conclusively identify the cause of the insulation breakdown and magnitude of the signal that coincided with the breakdown, they did note that the relay in this particular application is located in non-environmentally controlled

space which would impact aging mechanisms due to the temperature extremes. Additionally, the 251G/B-22-2 relay age was 39 years at the time of the event, which is only 1 year within the 40-60 year service life.

The team reviewed Constellation's root cause analysis report (RCAR) for the 251G/B-22-2 relay to determine the adequacy of the evaluation and the appropriateness of the extent-of-condition review. Independent reviews of the design documentation, drawings, maintenance history, and field walk-downs were performed to validate the cause of the relay failure. The team reviewed the design requirement and the relay setting information of the 13.8 kV fault protection relaying scheme to ensure proper equipment protection during transient and steady state conditions. The team also reviewed the history of the 251G/B-22-2 relay, along with other protective relays in the 13.8 kV system that were required during the event, to verify that the applicable test acceptance criteria and maintenance frequency requirements were met.

b. Findings

Deficient Evaluation and Untimely Corrective Action Associated with Induction Disc Binding on CO-8 Type Relays

Introduction: The team identified a finding of very low safety significance (Green) that involved a NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," because Constellation did not thoroughly evaluate and correct a degraded condition of CO-8 relay disc sticking or binding issues which can adversely impact the function of the EDGs and the electrical distribution protection scheme. Specifically, following the February 18, 2010, event Constellation did not identify and adequately evaluate the recent CO-8 relay failures due to sticking or binding of the induction discs in the safety related and non-safety related applications.

Description: The team reviewed Constellation's RCAR for the relay 2RY251G/B-22-2 on breaker 2BKR252-2202 which failed to trip open the breaker. The relay was a CO-8 ground fault over-current relay which had been in service for the life of the plant. The relay consists of an electromagnet and an induction disc which rotates to close a moving contact to a stationary contact to complete the breaker trip circuitry. The root cause analysis concluded that the magnetizing coil had shorted out the majority of the windings in a manner that current would pass but the induction disc would not rotate.

The team reviewed Constellation's maintenance and corrective action history of the CO-8 relay failures and noted that the induction disc type relays had a failure history associated with disc binding and sticking conditions. The team also noted that CO-8 relays and other induction disc type relays had a high failure rate for out of tolerance conditions during the performance of relays calibration procedures. The team determined that failures of the relay due to binding, sticking, and out of tolerance conditions can potentially impact the breaker trip operation and affect breaker coordination.

The failure history for binding, sticking, and out of tolerance conditions for the induction type relays were reviewed since 2007. The team found 40 failures since 2007 and 5 failures of the CO-8 type relays. Constellation has a total of 68 CO-8 type relays installed in safety related and non-safety related applications, all of which have been scheduled to be calibrated every 2 years since 2005. The team noted that from 1999 to

2005 as-found testing and calibration of the relays were performed every 4 years. The team reviewed the failure data of the CO-8 and other induction disc type relays prior to 2005 and concluded that the failure rate did not change significantly subsequent to the increase in calibration frequency. The CO-8 relay failures were noted to be 10 percent from 1999-2005.

Constellation replaced or cleaned the relays with sticking or binding conditions; however, the licensee did not place the relays in any system or component monitoring program. The relays were also not part of the system health tracking report. The team reviewed the historical failures of the CO-8 relays and noted that for some of the testing conditions, the induction disc needed to be mechanically agitated to free it from the binding or sticking conditions. The team reviewed the vendor and Electric Power Research Institute (EPRI) calibration and maintenance manual and determined that Constellations' calibration and inspection procedure did not include all of the recommended practices specified in the EPRI guideline related to inspection and cleaning of the induction disc units. Constellation entered this issue into the corrective action program (CRs 2010-004672 and 2010-004673).

Analysis: The team reviewed Constellation's root cause evaluation, which concluded the cause of the relay failure to be premature coil aging due to its operating environment and the magnitude of the current seen by the relay. The team concluded that there was no direct correlation between the coil failure and the historical binding and sticking conditions of the CO-8 relay discs. However the team determined that Constellation's failure histories of the CO-8 type relays were significant and the failure to evaluate the degraded conditions and implement timely and effective action to correct this condition adverse to quality was a performance deficiency. The CO-8 relays are used in multiple safety related and non-safety related applications.

The finding was more than minor, in accordance with NRC IMC 0612, Appendix B, "Issue Screening," (IMC 0612B) because, while it was not similar to any examples in IMC 0612, Appendix E, "Examples of Minor Issues" (IMC 0612E), it was associated with the equipment reliability attribute of the Mitigating Cornerstone and it adversely affected the associated cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The team evaluated this finding using IMC 0612 Attachment 4, "Phase 1-Initial Screening and Characterization of Findings." The finding is of very low safety significance (Green) because it is not a design or qualification deficiency, did not represent a loss of a safety function of a system or a single train greater than its TS allowed outage time, and did not screen as potentially risk significant due to external events. The historical relay failures did not result in an actual loss of system safety function.

The cause of the finding is related to the crosscutting area of Problem Identification and Resolution, Corrective Action Program because Constellation did not thoroughly evaluate the previous station operating experience of CO-8 relay induction disc sticking and binding issues such that resolutions addressed the causes and extent-of-condition (P.1(c)).

Enforcement: 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, Constellation did not

adequately evaluate and correct the degraded condition of CO-8 relays which can potentially impact the function of multiple safety related systems or component. Because the finding was of very low safety significance and has been entered into Constellation's corrective action program (CR 2010-004673), this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000317 & 318/2010006-03, Failure to Evaluate Degraded Conditions Associated With CO-8 Relays and Implement Timely and Effective Action to Correct the Condition Adverse to Quality.**

Deficient Offsite Power Distribution Tripping Scheme Design Control

Introduction: The team identified a finding having very low safety significance (Green) for failure to translate design calculation setpoint standard listed in calculation E-90-058 and E-90-061 of phase overcurrent relay (250) on feeder breakers 252-1101, 1102, 1103, 2101, 2102, and 2103 into the actual relay settings.

Description: During the relay settings review, the team identified that the service transformer 251G/ST-2 and service bus 251G/SB-21 ground overcurrent relays settings specified in the relay setting sheets did not support the values listed in the relay setting calculation E-90-61 for the 500/14 kV Service Transformer (P-13000-2). The value listed in the calculations for the 251G/ST-2 ground overcurrent relay tap settings was 2.5 amps and the actual field setting, which is set in accordance with the relay setting sheets, was found to be at 2 amps. For the service bus 251G/SB-21 the calculation setting of the time delay value was 4 seconds and the actual field settings was found to be at 3 seconds. Due to these discrepancies Constellation's engineering staff conducted an evaluation to determine if the actual field settings as specified in the relay setting sheets for the two overcurrent relays provided adequate coordination to ensure selective tripping. The relays are designed to detect ground faults on the 13.8 kV system which have not been cleared by the 500 kV transmission system relays and separate the station service transformer P-13000-2 from the grid. The team reviewed Constellation's evaluation and determined that there was no selective tripping coordination impact due to the relay setting discrepancies on 251G/ST-2 and 251G/SB-21. However, due to these discrepancies identified between the relay setting sheets and the design calculations, Constellation conducted an extent-of-condition review for the 13.8 kV systems to determine if other similar relay settings discrepancies exist.

As a result of the extent-of-condition review, Constellation identified that the phase overcurrent relay (250) pickup value for the six unit service transformers feeder breakers 252-1101, 1102, 1103, 2101, 2102, and 2103 were set at 1440 amps in accordance with the relay setting sheets and the values specified in the calculations E-90-058 and E-90-061 were 1200 amps.

The normal system operation design when offsite power is available, is the 4.16 kV system being supplied by the 13.8 kV system through six unit service transformers. The unit service transformers have overcurrent protection to protect against transformer faults in the primary or secondary side windings. This overcurrent protection per calculations E-90-058 and E-90-061 was limited to be at 1200 amps due to the breaker rating of all of the feeder breakers. Due to the as found relay setting of 1440 amps exceeding the breaker ratings of 1200 amps, Constellation conducted an operability analysis and performed a calculation which determined that the maximum load current possible during the worst case electrical distribution line-up condition would be 982

amps. The calculation demonstrated that the maximum load current possible during the worst case electrical distribution line-up would not challenge the feeder breaker ratings, and therefore would not cause the breaker to fail prior to the trip operation (tripping).

Analysis: The team determined that the failure to translate the design calculation setpoint standard values listed in the calculation E-90-058 and E-90-061 of phase overcurrent relay (250) on feeder breakers 252-1101, 1102, 1103, 2101, 2102, and 2103 into the actual relay settings was a performance deficiency.

The team determined that this finding was more than minor because it affected the Initiating Events Cornerstone attribute of equipment performance for ensuring the availability and reliability of systems to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Also, this issue was similar to Example 3j of IMC 0612, Appendix E, "Examples of Minor Issues," because the condition resulted in reasonable doubt of the operability of the component, and additional analysis was necessary to verify operability. The failure to translate adequate design calculation setpoint of phase overcurrent relays on the feeder breakers resulted in an as-found relay setting that exceeded the rating of the feeder breakers. The team determined that due to the as-found relay setting exceeding the breaker ratings, certain phase overcurrent conditions could have potentially caused the breaker to fail prior to the phase overcurrent relay sensing the degraded condition. The team determined that this condition could affect the recovery of the safety buses from the electrical grid. The team evaluated this finding using IMC 0612 Attachment 4, "Phase 1- Initial Screening and Characterization of Findings." This finding was determined to be of very low safety significance (Green) because these inadequate relay settings did not result in an actual loss of system safety function and Constellation also performed an evaluation and determined that the maximum load current possible would not challenge the feeder breaker ratings. The finding did not have a cross-cutting aspect because the most significant contributor to the performance deficiency was not reflective of current licensee performance.

Enforcement: This finding was not a violation of regulatory requirements because the unit service transformers and the overcurrent protection relays are not a system or component covered under 10 CFR Part 50, Appendix B. The issue has been entered into the licensee's corrective action program (CR 2010-002123. Because this finding does not involve a violation and has very low safety significance, it is identified as **FIN 05000317 & 318/2010006-04: Failure to Translate Design Calculation Setpoint of Phase Overcurrent Relay on Feeder Breakers.**

2.4 Breaker 2BKR152-2501 (4 kV Bus 25 Normal Feed) Failed to Trip Open

a. Inspection Scope

The team reviewed design requirements, drawings, and maintenance history of the 2BKR152-2501 breaker. The breaker inspection reviewed the maintenance practice and procedure of overhauling the 4 kV breakers to determine if adequate test acceptance criteria were established and followed vendor recommendations. The team reviewed Constellation's root cause analysis report for the 2BKR152-2501 to determine the adequacy of the evaluation and the appropriateness of the extent-of-condition review. Independent reviews of the design documentation, drawings, maintenance history, and field walkdowns were performed to validate the cause of the breaker failure.

Additionally, operations, maintenance, and engineering staff were interviewed to confirm the observations and causes cited in Constellation's evaluation of this issue. The team reviewed the adequacy of associated preventive maintenance, corrective actions, and post maintenance testing performed on the 2BKR152-2501 breaker. Bus 25 supplies power to three Unit 2 circulating water pumps.

b. Findings

No findings of significance were identified for this equipment issue. The team determined that this failure of 2BKR152-2501 to open had no adverse consequence during this event.

2.5 Breaker 2BKR252-2201 (13 kV Unit 2 RCP Buses Normal Feed) Failed to Trip Open

a. Inspection Scope

The team reviewed design requirements, drawings, and maintenance history of the 2BKR252-2201 breaker. The team reviewed the maintenance practice and procedure of overhauling the 13.8 kV breakers to determine if adequate test acceptance criteria were established and followed vendor recommendations. Constellation concluded the cause of the breaker failing to open was infant mortality (i.e., manufacturing defect). The team reviewed Constellation's root cause analysis report for the 2BKR252-2201 to determine the adequacy of the evaluation and the appropriateness of the extent-of-condition review. Independent reviews of the design documentation, drawings, maintenance history, and field walkdowns were performed to validate the cause of the breaker failure. Additionally, operations, maintenance, and engineering staff were interviewed to confirm the observations and causes cited in Constellation's evaluation of this issue. The team reviewed the adequacy of associated preventive maintenance, corrective actions, and post maintenance testing performed on the 2BRK252-2201 breaker.

b. Findings

No findings of significance were identified.

3. Human Performance

3.1 Event Diagnosis and Crew Performance

a. Inspection Scope

The team interviewed the operations crew that responded to the February 18, 2010, event, including three senior reactor operators, the shift manager, the control room supervisor, the shift technical advisor, two reactor operators, and three equipment operators to determine whether the operators performed in accordance with procedures and training. The team also reviewed narrative logs, post-transient reports, condition reports, PPC trend data, and procedures implemented by the crew.

b. Findings/Observations

Deficient Procedure Guidance for CVCS Letdown Restoration

Introduction: A self-revealing Green NCV of TS 5.4.1.a, "Procedures," was identified because Constellation did not establish adequate procedures for restoration of CVCS letdown flow. Deficient operating instructions prevented timely restoration of letdown flow following letdown isolation, which ultimately led to exceeding the TS high limit for pressurizer level.

Description: On February 18, 2010, Unit 1 was operating at 93% reactor power in preparation for main steam safety valve testing with the 11 and 13 charging pumps operating and increased letdown flow balanced with charging flow. At 8:24 a.m., a phase to ground overcurrent fault on 12B RCP switchgear resulted in an automatic reactor trip on Unit 1. Protective relaying isolated plant service transformer P-13000-2, which de-energized Unit 1 4 kV bus 14. Instrument Bus 1Y10, which is normally fed from 4 kV Bus 14, de-energized, isolating CVCS letdown by closing letdown isolation valve 1-CVC-515. The 1B EDG automatically started on bus undervoltage and re-powered 4 kV Bus 14 about 8 seconds later.

Charging pump 13 stopped on loss of power when 14 Bus de-energized and charging pump 11, powered from 4 kV Bus 11, continued running. At 8:31 a.m., operators re-started charging pump 13. Charging pumps remained running and pressurizer level increased as expected. Operators performed makeup to the CVCS Volume Control Tank (VCT) from 8:50 a.m. to 9:11 a.m. in order to maintain VCT inventory while the two running charging pumps transferred VCT contents into the pressurizer. At 8:58 a.m., 34 minutes after the reactor trip, and with pressurizer level approaching the high end of the EOP pressurizer level control band (180"), operators turned off charging pump 13. Charging pump 11 continued to run in anticipation of restoring letdown. At 9:02 a.m., operators stopped charging pump 11 because pressurizer level was above the EOP high level limit.

At 9:12 a.m., operators made their first attempt to restore letdown in accordance with OI-2A, "Chemical and Volume Control System", Section 6.7, "Starting Charging and Letdown" by re-starting charging pump 11 and shortly thereafter opening letdown isolation valves. They were not successful in restoring letdown. Subsequent post-event analysis of system parameter data stored on the plant computer indicated that excess flow check valve 1-CVC-343 was closed. Inadequate procedural guidance prevented operators from re-opening the check valve to establish letdown flow. The procedure for starting letdown consisted of setting letdown downstream control valves at 20% open in manual, starting a charging pump to cool the letdown stream, then opening letdown upstream isolations 1-CVC-515 and 1-CVC-516 to establish letdown flow. OI-2A did not contain any information related to the possibility that excess flow check valve 1-CVC-343 might be closed and did not provide direction for opening the valve.

Operators were confused by indicated letdown flow remaining downscale and took about 7 minutes re-confirming the system lineup and monitoring their instrumentation before stopping charging pump 11. They did not use OI-2A, Section 6.6, "Securing Charging and Letdown" to stop charging and letdown because letdown was not yet established. Initial conditions for using Section 6.6 were not met. Operators did not recognize a need for simultaneously stopping charging and letdown in accordance with the general methodology of Section 6.6. An additional 17 minutes elapsed from the time operators stopped the charging pump 11 until they closed the upstream letdown isolation valves.

Post-event data analysis showed the downstream letdown piping temperature steadily increased into the 400° to 500°F range during the 17 minutes between stopping the charging pump and closing the upstream letdown isolation valves because of hot reactor coolant flowing in the letdown line through the 10 gallons per minute (gpm) orifice which bypasses around the excess flow check valve. Typically, reactor coolant is cooled by charging flow through the letdown regenerative heat exchanger to about 220°F in the letdown line. It is postulated that during letdown restoration attempts, the RCS which was greater than 2000 psi pressure, re-pressurized the letdown line which rapidly collapsed steam voids in the hot (400°F-500°F) letdown piping and re-closed the excess flow check valve because of water hammer. A differential pressure was then established across the check valve, maintaining it closed. The restoration method provided by procedure OI-2A did not contain actions necessary for pressure equalization across this spring-loaded check valve.

During the second letdown restoration attempt at 10:44 a.m., letdown continued to flow through the bypass orifice for 21 minutes after stopping charging pump 11. This action again heated the letdown line to near reactor coolant temperature. On the third attempt at 11:39 a.m., operators closed letdown isolation valves just 2 minutes after stopping the charging pump, which left the letdown line in a relatively cool state, such that the transient conditions on the fourth and final attempt did not re-close the excess flow check valve. Operators made a total of four attempts to restore letdown over 5 hours before letdown was finally restored at 1:17 p.m.

Pressurizer level remained above the specified limit in EOP-1 for all but a few minutes of approximately 5 hours following the reactor trip. Throughout this period, operators attempted to control pressurizer level from the EOP high level limit of 180" to the normal full power level of 215". This range was based on the constraints of controlling pressurizer level below the TS high limit of 225" and high enough to prevent overfilling the VCT. With letdown unavailable, operators were only able to lower pressurizer level through the 6 gpm reactor coolant pump seal bleed off that returns to the VCT.

The team observed that unnecessarily conservative procedural requirements for ensuring adequate shutdown margin in NEOP-301, "Operator Surveillance Procedure" contributed to the operating crew's sense of urgency for letdown restoration. Operators recognized that the 2400 gallon RCS boration required to satisfy the requirements of NEOP-301 would cause pressurizer level to significantly exceed the TS high level limit if performed with letdown isolated.

Other options existed for controlling VCT level such that bleed off could be allowed to reduce pressurizer level to within the EOP band. These included intentionally draining the VCT to the liquid waste system and aligning bleed off flow to return to the reactor coolant drain tank instead of to the VCT. However, the station does not have an abnormal operating procedure for responding to a sustained loss of letdown and therefore no procedural guidance existed for using other methods to control VCT level.

Around noon, shortly after the third attempt to restore letdown, operators became involved in shifting main turbine gland sealing steam supply from main steam to auxiliary steam and failed to control RCS temperature. Loop temperature rose approximately 5°F, causing pressurizer level, already high at 215", to rise and peak at 231." Pressurizer level remained above the TS 3.4.9 high limit of 225" for approximately 7

minutes until operator actions which were taken to lower RCS temperature succeeded in reducing level to below the TS limit.

The excess flow check valve did not re-close on the fourth restoration attempt. Letdown was successfully re-established at 1317, approximately 5 hours after event initiation. Constellation has established procedure guidance relating to letdown restoration following closure of the excess flow check valve. The issue was entered into their CAP for further evaluation as CR 2010-001378.

Analysis: The performance deficiency is that Constellation did not establish adequate procedures for restoring letdown. Multiple factors contributed to pressurizer level exceeding the TS high limit. These included time pressure from overly conservative procedure requirements related to maintaining shutdown margin, filling the pressurizer above the EOP band when RCS temperature was below its nominal no-load value, makeup to the VCT to the high end of its control band when pressurizer level was already high, the absence of proceduralized options for controlling VCT level, and inattentiveness to reactor coolant temperature control. However, inadequate procedure guidance for letdown restoration is the primary reason which led to operation outside of EOP pressurizer level limits for an extended period of time and unnecessarily challenged operators in their attempts to maintain pressurizer level control.

The team determined this finding is more than minor because it is associated with the procedure quality attribute of the Mitigating Systems Cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding is of very low safety significance (Green) because it is not a design or qualification deficiency, did not represent a loss of a safety function of a system or a single train greater than its TS allowed outage time, and did not screen as potentially risk significant due to external events. This finding has a crosscutting aspect in the area of Human Performance, resources, because Constellation did not ensure that procedures for restoring CVCS letdown were complete and accurate (H.2(c)).

Enforcement: TS 5.4.1.a requires, in part, that written procedures be established, implemented, and maintained for activities described in Appendix A of Regulatory Guide (RG) 1.33, "Quality Assurance Program Requirements (Operation)." Specifically, Section 3 of RG 1.33, Appendix A, "Instructions for energizing, filling, venting, draining, startup, shutdown, and changing modes of operation should be prepared, as appropriate, for the following systems," includes the Letdown/Purification System. Contrary to the above, on February 18, 2010, the operators were unable to restore charging and letdown using the existing instructions of OI-2A, "Chemical and Volume Control System," due to inadequacy of the procedure. Because this issue is of very low safety significance (Green) and Constellation entered this issue into their corrective action program as CR 2010-001378, this finding is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000317/318/2010006-05, Failed to Establish Adequate Procedures for Letdown Restoration).**

3.2 Communications and Emergency Plan Applicability

a. Inspection Scope

This event involved an automatic reactor trip of both units with multiple complicating degraded equipment issues. Each unit lost one 500 kV offsite power supply (the Red Bus). In addition, Unit 2 lost forced RCS circulation when all four RCPs tripped, the 2B EDG failed to reenergize the Unit 2 24 4 kVafety bus, and the Unit 2 normal heat removal sink (main condenser) was unavailable for an extended time. Operators notified the NRC of the event at 11:47 a.m. on February 18 in accordance with 10 CFR 50.72. Operators determined that emergency action level (EAL) entry criteria were not met and accordingly did not declare an emergency event. The team reviewed operator logs, emergency procedures, the Emergency Plan, plant operating data, and interviewed station personnel to verify operators properly assessed the EAL entry criteria and notified the NRC of the event.

b. Findings

No findings of significance were identified.

4. Organizational Response

4.1 Immediate Response and Restart Readiness Assessment

a. Inspection Scope

The team interviewed personnel, reviewed various procedures and records, observed plant operators and station meetings, and performed plant walkdowns to assess station personnel's immediate response to the event and restart readiness assessment. The licensee restart readiness assessment was performed in accordance with CNG-OP-1.01-1006, Post-Trip Reviews, Rev. 1.

b. Findings

No findings of significance were identified.

Operators promptly announced the event, implemented the appropriate emergency operating procedures, and correctly assessed EALs. However, human performance deficiencies and/or procedure deficiencies led to Unit 1 exceeding the TS pressurizer level limit (Section 3.1) and untimely verification of offsite power source availability. Constellation augmented the on-shift staff promptly to support initial diagnosis and corrective actions to address the numerous degraded equipment problems.

The post-trip review was sufficient to ensure operator performance issues and significant equipment issues were identified and addressed. Notwithstanding, the team identified several deficiencies which posed challenges to the effectiveness of the licensee restart readiness assessment (CR 2010-004502). The team discussed each issue with licensee management who entered the issues into the corrective action program, as applicable. One notable issue was that station personnel did not quarantine several failed components (breaker 152-2501, 2B EDG oil sensing line contents, relay 251G/B-22-2). This adversely limited the as-found information available to diagnose the failure mechanisms.

4.2 Post-Event Root Cause Analysis and Actions

a. Inspection Scope

The team reviewed the RCAR for the 2010 Dual Unit Trip to determine whether the causes of the event and associated human performance and equipment challenges were properly identified. Additionally, the team assessed whether interim and planned long term corrective actions were appropriate to address the cause(s).

b. Findings

No findings of significance were identified.

The RCAR properly evaluated causes and appropriate corrective actions for several equipment challenges. For example, evaluation and corrective actions for the Unit 1 roof leakage which initiated the ground fault event were comprehensive. In addition to the root cause, the RCAR identified several contributing causes including deficient maintenance rule implementation and performance monitoring, over reliance and inadequate vendor oversight, incomplete incorporation of Quality Assurance findings, and insufficient engineering involvement in roof construction. Interim corrective actions were appropriate and long term actions were being developed through the corrective action program.

In several other areas the team determined the RCAR lacked depth and technical rigor in identifying and assessing potential causes. In each case the RCAR developed an explanation for what may have caused the event or equipment response, but did not fully develop other potential causes. Examples included:

- RCAR did not identify the failure to implement an Agastat relay monitoring program when the 10 year replacement PM was eliminated (2B EDG failure);

- RCAR conclusion that loose diaphragm retaining ring screws on the Agastat relay were caused by vibration and were the result of a manufacturing defect were not well supported by the contracted failure analysis or data evaluation (2B EDG failure);

- Information that the relay induction disc did not freely rotate back to the original position during bench troubleshooting, was not incorporated into the RCAR (relay 2RY251G/B-22-2 failure);

- RCAR did not thoroughly review previous internal OE regarding induction disc failure on CO-8 type relays. Station personnel did not recognize the sensitivity of the induction disc to sticking/binding (relay 251G/B-22-2 failure);

- RCAR did not include or address the 2008 as-found inspection results which found the armature linkage misaligned and the trip coil loose. This was an unexpected and infrequent occurrence (breaker 152-2501 failure); and

- RCAR concluded the 152-2501 breaker failure was due to mechanical binding in the trip linkage caused by human error during the October 2008 trip armature bolt replacement. However, corrective actions did not investigate other breaker maintenance performed by these technicians during that time period.

The team reviewed these issues and determined that none of these issues involved violations of regulatory requirements or were already described as part of the previously discussed violations in this report.

4.3. Review of Operating Experience

a. Inspection Scope

The team reviewed Constellation's use of pertinent industry and station operating experience (OE), including evaluation of potential precursors to this event.

b. Findings

No findings of significance were identified.

The team identified several instances where Constellation had not effectively evaluated or initiated actions to address related station or industry operating experience issues. Examples included:

- Unit 1 and Unit 2 45 foot switchgear room roof leakage onto electrical switchgear had been identified numerous times since 2002, but not corrected. Fifty-eight open work orders for roof leaks, several > 24 months old, had not been implemented (Section 2.1).

- Industry OE has reported numerous problems with Agastat series 7000 relays; several affecting reliability of the actuation setpoint. Yet engineers extended both the service life and calibration periodicity of the EDG lube oil pressure trip time delay relays beyond the vendor specified periods without adequate technical basis (Section 2.2).

- Technicians routinely did not consider relay actuation outside of the acceptance band to be a test failure. Often no condition report was initiated and no drift/performance trending was performed. Corrective action was often limited to adjusting the as-left setpoint to within the acceptance band (e.g, agastat 7000 series time delay relays, CO-8 overcurrent protection relays) (CR 2010-004090).

The team reviewed these issues and determined that none of these issues involved violations of regulatory requirements or were already described as part of the previously discussed violations in this report.

5. Risk Significance of the Event

a. Initial Assessment

The initial risk assessment for this event is documented in the enclosed SIT charter.

b. Final Assessment

Onsite follow-up and discussions with the Constellation PRA staff verified that there were no additional plant conditions or operator performance issues that significantly alter the initial event risk assessments performed for both units. The Unit 1 reactor trip estimated conditional core damage probability (CCDP) was calculated to be 2.6 E-6 for the February 18, 2010 reactor trip. The Unit 2 reactor trip CCDP, accounting for a loss of reactor coolant forced circulation (all RCPs tripped), loss of heat sink (main

condenser), and failure of the 2B EDG to run, was estimated to be 1.5 E-5 for the February 18, 2010 event.

4OA3 Follow-up of Events

.1 (Closed) Licensee Event Report (LER) 05000317/2010-001, Reactor Trip Due to Water Intrusion into Switchgear Protective Circuitry

On February 18, at 8:24 a.m., the Unit 1 reactor automatically tripped from 93 percent reactor power in response to a RCS low flow condition. Water had leaked through the auxiliary building roof into the 45' switchgear room, causing an electrical ground which tripped the 12B RCP, thereby initiating the reactor protection system trip on RCS low flow. Three of the four Unit 1 RCPs continued operating. The electrical ground and failure of a ground fault protection relay caused service transformer P-13000-2 to isolate, thereby deenergizing the 14 4 kV safety bus and the 1Y10 120 volt instrument bus. The 1B EDG automatically started and reenergized the 14 bus as designed. The LER accurately described operator response to the event. The team reviewed the LER and identified no findings of significance beyond those previously documented in this report (NRC Inspection Report No. 05000317/2010006). This LER stated a supplemental LER will document a complete description of corrective actions after the event analysis and cause determination is complete. This LER is closed.

.2 (Closed) Licensee Event Report (LER) 05000318/2010-001, Reactor Trip Due to Partial Loss of Offsite Power

On February 18, at 8:24 a.m., the Unit 2 reactor automatically tripped from 99.5 percent reactor power due to a loss of power to all four RCPs and the associated reactor protection system RCS low flow trip. The event emanated from a ground fault on Unit 1 (see Section 2.1). A ground O/C relay failed to actuate as designed, permitting the Unit 1 ground O/C condition to reach Unit 2. Unit 2 electrical protection responded by deenergizing the 500 kV "Red Bus" offsite power supply and multiple onsite electrical buses including the 24 4 kV safety bus. The 2B EDG started as designed, but tripped on low lube oil pressure (see Section 2.2). The LER accurately described operator response to the event. The team reviewed the LER and identified no findings of significance beyond those previously documented in this report (NRC Inspection Report No. 05000317/2010006). This LER stated a supplemental LER will document a complete description of corrective actions after the event analysis and cause determination is complete. This LER is closed.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On April 30, 2010, the team presented their overall findings to members of Constellation management led by Mr. G. Gellrich, Site Vice President, and other members of his staff who acknowledged the findings. The team confirmed that proprietary information reviewed during the inspection period was returned to Constellation.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Gellrich	Site Vice President
K. Allor	Senior Operations Instructor
P. Amos	Performance Improvement
P. Darby	Principal Assessor, Engineering Quality Performance Assessment
S. Dean	Manager, Maintenance
M. Draxton	Manager, Nuclear Training
D. Fitz	Communications
M. Flynn	HR Director
D. Frye	Manager, Operations
M. Gahan	GS, Design Engineering
G. Gellrock	Supervisor
S. Henry	Manager, Work Management
J. Koebel	PRA
D. Lauver	Director, Licensing
W. Mahaffee	Supervisor, Chemistry Operation
J. McCullum	Supervisor, Instrumentation and Controls
K. Mills	Assistant Operations Manager
P. O'Malley	Quality Performance Assessment
T. Riti	GS, System Engineering
K. Roberson	Manager, NSS
A. Simpson	Engineering/Licensing
R. Stark	Design Engineering
T. Trepanier	Plant General Manager

Others

S. Gray	Power Plant Research Program Manager, Department of Natural Resources, State of Maryland
M. Griffin	Nuclear Emergency Preparedness Coordinator, Department of the Environment, State of Maryland

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000317/318/2010006-01	NCV	Failure to Thoroughly Evaluate and Promptly Correct Degraded Conditions Associated with Auxiliary Building Roof Leakage (Section 2.1)
05000317/318/2010006-02	AV	Inadequate Preventive Maintenance Results in the Failure of the 2B Emergency Diesel Generator (Section 2.2)
05000317/318/2010006-03	NCV	Failure to Evaluate Degraded Conditions Associated with CO-8 Relays and Implement

		Timely and Effective Action to Correct the Condition Adverse to Quality (Section 2.3)
05000317/318/2010006-04	FIN	Failure to Translate Design Calculation Setpoint of Phase Overcurrent Relay on Feeder Breakers (Section 2.3)
05000317/318/2010006-05	NCV	Failed to Establish Adequate Procedures for Letdown Restoration (Section 3.1)

Opened and Closed

05000317/2010-001	LER	Reactor Trip Due to Water Intrusion into Switchgear Protective Circuitry (Section 4OA3.1)
05000318/2010-001	LER	Reactor Trip Due to Partial Loss of Offsite Power (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Drawings

61004, Single Line Meter & Relay Diagram 13 kV System, Rev. 26
61001SH0001, Electrical Main Single Line Diagram FSAR Fig. No. 8-1, Rev. 42
63070SH0009, Schematic Diagram 13 KV Service Bus 22 RCP Bus Feeder Breaker 252-2201, Rev. 11
63049, AC Schematic Diagram Service Bus 22 & Service Transformer P-13000-2, Rev. 17

Condition Reports (CR)

IRE-000-433	CR 2009-008115	CR 2010-001707
IRE-004-399	CR 2009-008537	CR 2010-001779
IRE-004-400	CR 2009-008635	CR 2010-001780
IRE-011-621	CR 2010-001330	CR 2010-001781
IRE-011-769	CR 2010-001340	CR 2010-001782
IRE-020-768	CR 2010-001351	CR 2010-001783
IRE-020-769	CR 2010-001355	CR 2010-001784
IRE-020-776	CR 2010-001381	CR 2010-001787
IRE-022-227	CR 2010-001516	CR 2010-001813
IRE-026-951	CR 2010-001517	CR 2010-001888
IRE-028-751	CR 2010-001544	CR 2010-002875
IRE-031-691	CR 2010-001553	CR 2010-004411
IRE-032-766	CR 2010-001586	CR 2010-004493
CR 2008-001582	CR 2010-001592	CR 2010-004502
CR 2008-002458	CR 2010-001682	CR 2010-004613
CR 2009-004060	CR 2010-001685	CR 2010-004652
CR 2009-004074	CR 2010-001690	CR 2010-004672
CR 2009-004606	CR 2010-001691	CR 2010-004673
CR 2009-005508	CR 2010-001671	CR 2010-004674
CR 2009-005629	CR 2010-001699	
CR 2009-006187	CR 2010-001700	

Maintenance Orders
MO #1200801597, Replace Flex Hoses on the 1B EDG
MO #2199901416, Calibrate 2B EDG Lube Oil Pressure Gauge, 2-PI-4796
MO #2200000476, Perform E-19 on 2B EDG Agastat Relays
MO #2200201832, 2B EDG Engine Stop Relay
MO #2200401152, 2B EDG Engine Stop Relay
MO #2200501401, 2B EDG Engine Stop Relay
MO #2200700554, Replace Flex Hoses on the 2A EDG
MO #2200700555, Replace Flex Hoses on the 2B EDG
MO #2200700852, 2B EDG Engine Stop Relay

Operability Evaluation
OE-2009-003712

Procedures
Auxiliary Building Walkdown Results, MN-1-319 "Structure and System Walkdowns," Rev. 5
Auxiliary Building Walkdown Results, MN-1-319 "Structure and System Walkdowns," Rev. 7
10-02 "Rain/Snow Water Intrusion Compensatory Measures," Rev. 1
CNG-AM-1.01-2000, "Scoping and Identification of Critical Components," Rev. 00200
CNG-CA-1.01-1000, "Corrective Action Program," Rev. 0200
CNG-OP-1.01-1006, "Post Trip Reviews," Rev. 00001
CNG-OP-1.01-2000, "Operations Logkeeping and Station Rounds," Rev. 00100
CNG-QL-1.01-1007, "Quality Performance Assessment Process," Rev. 00201
CNG-PR-1.01-1009, "Procedure Use and Adherence Requirements," Rev. 00400
FTE-87, "Powell 13.8 kV Type PVDH Vacuum Circuit Breaker Inspection," Rev. 00101
FTE-51A, "General Electric Cubicle Inspection," Rev. 2
FTE-59, "Periodic Maintenance, Calibration and Functional Testing of Protective Relays," Rev. 5
MN-1-319 "Structure and System Walkdowns," Rev. 7
NO-1-200, "Control of Shift Activities, Rev. 04401
NO-1-201, "Calvert Cliffs Operating Manual," Rev. 02000
OI-2A, "Chemical and Volume Control System," Rev. 55/Unit 1

Miscellaneous
Control Room Operations Narrative Logs
Operations Administrative Policy 90-7, Guidelines, System Expert and Shift Crew Ownership Program Guidelines and Expectations, January 27, 2010, Change 15
Plant Areas System 102 Walkdowns, 1- Unit 1 performed January 5, 2010, & March 31, 2010
System 102 "Plant Areas," Maintenance Rule Scoping Document, Rev. 30
Site Roof Leakage Condition Report Scoping Document
U-1 Alarm History Printout for February 18, 2010
U-2 Alarm History Printout for February 18, 2010
U-1 Sequence of Events Recorder Printout for February 18, 2010
U-2 Sequence of Events Recorder Printout for February 18, 2010

- Engineering Service Package ES200100067, Revision 1, Delete Requirement in E-406 Sec 234.0.1 to Change Out Agastat Prior to Ten Years and Remove Testing Recommendations to VTM 15-167-001
- Procedure E-406, Rev. 0, Installation and Replacement for Agastat Relays
- RO01617, Revision 4, Guideline for Testing Agastat Relay Models
- Constellation Nuclear Generation Fleet Administrative Procedure CNG-CA-1.01-1004 Root Cause Analysis, Revision 00301

- Procedure FTI-328, Revision 1, Calibration Check/Calibration of Allen-Bradley Pressure Switches
- Rover Maintenance Approval and Closeout Form, MN-1-101, Revision 03601, 2A EDG Oil Sensing Line Flush
- Calvert Cliffs Surveillance Test Procedure, STP O-8B-2, Revision 26, Test of 2B DG and 4 kV Bus 24 LOCI Sequencer
- Calvert Cliffs Surveillance Test Procedure, STP O-8A-2, Revision 26, Test of 2A DG and 4 kV Bus 24 LOCI Sequencer
- Operating Experience OE13852 – Inadequate Venting of the Emergency Diesel Generator Lubricating Oil System
- Schematic Diagram Diesel Generator No. 2B Engine Control, No. 63086SH0010, Revision 39
- Work Order C90791765, 2B Diesel Generator Failed to Start and Load on the 24 4 kV Bus on an ESFAS UV Signal
- Operating Experience, ACE 013617, Surry EDG Agastat Relay Failure
- Constellation Nuclear Generation Fleet Administrative Procedure CNG-AM-1.01-1018 Preventive Maintenance Program, Revision 00400
- Vendor Manual 15167-001-1001, Agastat Timing Relays 7000 Series
- Vendor Manual 15167-001-1005, Tyco Electronics
- Herguth Labratories Crankcase Oil Sample Data
- Troubleshooting Data Sheet to Determine Cause of 2B EDG Trip after Closing onto 24 4 kV Bus
- CCNPP Procurement Engineering Specification, PES – 25180, Revision 17, Agastat Relays and Associated Hardware
- Maintenance Strategy 2RY2DG2BA/T3A Relay
- 2-PS-4798 Master Calibration Data Package, 2/19/10

Root Cause Analysis
CNG-CA-1.01-1004 "Root Cause Analysis" Dual Unit Trip, Rev 00301

Apparent Cause Evaluation
IRE-007-705

Calculations/Engineering Evaluation Reports
E-90-058, Breaker 252-1101, 1102, 1103, Rev. 2
E-90-061, Breaker 252-2101, 2102, 2103, Rev. 2
E-90-062, Breaker 252-2201, Rev. 2
RCS Letdown Line Evaluation for Potential Water Hammer dated 3/16/10

Completed Tests/Surveillances
E-30, 4.16 kV Magne-Blast Circuit Breaker Overhaul Procedure, Performed 10/04/04
FTE-51, 4 kV General Electric Magne-Blast Circuit Breaker Inspection, Performed 11/18/08, 4/14/05
FTE-59, Periodic Maintenance, Calibration and Functional Testing of Protective Relays, Performed 04/06/00, 03/26/03, 05/03/04, 10/01/05, 05/08/07, 10/10/07, 03/08/08, 11/20/08, 02/28/09
FTE-87, Powell 13.8 kV Type PVDH Vacuum Circuit Breaker Inspection, Performed 3/15/07
STP-O-90-1 and STP-O-90-2, "AC Sources and Onsite Power Distribution Systems 7 Day Operability Verification, Rev. 22

LIST OF ACRONYMS

AV	Apparent Violation
CC	Calvert Cliffs
ΔCDF	Increase in Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CVCS	Chemical and Volume Control System
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESDP	Emergency Shutdown Panel
gpm	Gallons per Minute
IMC	Inspection Manual Chapter
kV	Kilovolt
ΔLERF	Increase in Large Early Release Frequency
LER	Licensee Event Report
LO	Lube Oil
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OC	Overcurrent
OE	Operating Experience
PM	Preventive Maintenance
PORC	Plant Onsite Review Committee
PPC	Plant Process Computer
PRA	Probabilistic Risk Assessment
RCAR	Root Cause Analyses Report
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RG	Regulatory Guide
RPS	Reactor Protection System
SDP	Significance Determination Process
SM	Shift Manager
SPM-A	Woodward SPM-A Synchronizer
SRA	Senior Reactor Analyst
SIT	Special Inspection Team
SPAR	Standardized Plant Analysis Risk
ST	Surveillance Test
TD	Time Delay
TS	Technical Specification
UV	Under-Voltage
VCT	Volume Control Tank

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475 ALLENDALE ROAD
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SPECIAL INSPECTION TEAM CHARTER

February 22, 2010

MEMORANDUM TO: Glenn Dentel, Manager
Special Inspection Team

David Kern, Leader
Special Inspection Team

FROM: David C. Lew, Director **/RA/**
Division of Reactor Projects

Darrell J. Roberts, Director **/RA/**
Division of Reactor Safety

SUBJECT: SPECIAL INSPECTION TEAM CHARTER - CALVERT CLIFFS PARTIAL LOSS OF OFFSITE POWER AND DUAL UNIT TRIP WITH COMPLICATIONS ON FEBRUARY 18, 2010

In accordance with Inspection Manual Chapter (IMC) 0309, "Reactive Inspection Decision Basis for Reactors," a Special Inspection Team (SIT) is being chartered to evaluate a Calvert Cliffs dual unit trip with complications which occurred on February 18, 2010. The decision to conduct this special inspection was based on meeting multiple deterministic criteria (multiple failures in equipment needed to mitigate an actual plant event, significant unexpected system interactions, and events involving safety related equipment deficiencies) specified in Enclosure 1 of IMC 0309 and the event representing a preliminary conditional core damage probability in the low E-6 range for Unit 1 and low E-5 range for Unit 2.

The SIT will expand on the inspection activities started by the resident team immediately after the event. The team will review Constellation's organizational and operator response to the event, equipment and design deficiencies, and the causes for the event and subsequent issues. The team will collect data, as necessary, to refine the existing risk analysis. The team will also assess whether the SIT should be upgraded to an Augmented Inspection team.

The inspection will be conducted in accordance with the guidance contained in NRC Inspection

Procedure 93812, "Special Inspection," and the inspection report will be issued within 45 days following the final exit meeting for the inspection.
The special inspection will commence on February 22, 2010. The following personnel have been assigned to this effort:

Manager:	Glenn Dentel, Branch Chief, Projects Branch 1, Division of Reactor Projects (DRP), Region I
Team Leader:	David Kern, Senior Resident Inspector DRP, Region I
Full Time Members:	Peter Presby, Operations Inspector Division of Reactor Safety (DRS), Region I
	Manan Patel, Electrical Inspector DRS, Region I
	Brian Smith, Resident Inspector DRP, Region I
Part Time Member:	William Cook, Senior Reactor Analyst DRS, Region I

Enclosure: Special Inspection Charter

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Enclosure: Special Inspection Charter

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DATE	02/22/10		02/22/10		02/22/10		02/22/10		02/22/10	

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Special Inspection Team Charter
Calvert Cliffs Nuclear Power Plant
Dual Unit Trip with Complications due to a Partial Loss of Offsite Power
on February 18, 2010

Background:

At 8:24 a.m. on February 18, 2010, Calvert Cliffs Unit 1 experienced an unexpected loss of the 12B reactor coolant pump (RCP). The loss of the RCP trip resulted in a valid reactor protection system (RPS) actuation on low reactor coolant system flow and a Unit 1 trip.

At approximately the same time, Unit 2 experienced a loss of the 500 kV to 13.8 kV transformer for the "Red Bus" (500 kV). The Red Bus is the feeder for offsite power for the Unit 1 "14" and Unit 2 "24" 4 kV safety buses. Unit 2 experienced the following system/component responses based on the loss of the Red Bus: loss of the non-safety related buses, a loss of load RPS trip signal, a loss of all RCPs, and a Unit 2 trip. The loss of the non-safety related buses resulted in the loss of the circulating water pumps, the main feedwater pumps, and condensate pumps, and the subsequent loss of the normal heat sink. Bus 21, the other Unit 2 safety 4 kV bus, normally aligned to the Black Bus, remained energized.

The loss of power to the "14" and "24" 4 kV safety buses resulted in a valid start signal for the 1B and 2B EDGs, respectively. The 1B EDG started and re-powered the "14" safety bus; however, the 2B EDG tripped during loading resulting in the loss of the "24" safety bus. This resulted in the unavailability of the "B" safety train. Calvert Cliffs subsequently restored power to the "24" safety bus via the Black Bus alternate power supply.

Unit 1 was cooled down and entered a refueling outage that was originally scheduled to begin on February 20, 2010. Unit 2 was stabilized on natural circulation, and normal decay heat removal was subsequently restored; the plant has entered a forced outage.

At the time of the event, the resident team responded to the control room and monitored licensee actions to stabilize the plant and restore offsite power. An NRC regional inspector was also deployed to the site to supplement the resident staff.

Basis for the Formation of the SIT:

The IMC 0309 review concluded that three deterministic criteria were met. The deterministic criteria met included: 1) multiple failures of plant equipment in systems used to mitigate an event; 2) significant unexpected system interactions; and 3) events involving safety related equipment deficiencies. These criteria were met based on the partial loss of offsite power due to the transformer loss, and the subsequent failure of the 2B EDG to start and restore a safety bus. In addition, the system interactions between the 12B RCP trip and the transient, which resulted in the opposite 500 kV transformer loss, were unexpected. The Unit 2 transformer loss also resulted in a complete loss of forced flow to Unit 2 due to the expected loss of all four RCPs, and the loss of the Unit 2 main condenser as a heat sink.

The event was also evaluated for risk significance because the IMC 0309 review concluded that at least one deterministic criteria was met. Based upon best available information, the Region I Senior Risk Analyst (SRA) conducted a preliminary risk estimate for each unit on February 18. Using the Graphical Evaluation Module initiating event quantification tool and the Calvert Cliffs Unit 1 and Unit 2 Standardized Plant Analysis Risk (SPAR) models, the conditional core

damage probability (CCDP) for Unit 1 was estimated to be in the low E-6 range, and the Unit 2 estimated CCDP was in the low E-5 range. On February 19, 2010, the SRA discussed these results with the Constellation PRA staff and determined that the risk estimates (CCDP) performed by Constellation favorably compared to the NRC SPAR model generated values.

Based upon the preliminary CCDP estimates, and in accordance with IMC 0309, the Unit 1 and Unit 2 events fall within the overlap ranges of No Additional Inspection and Special Inspection Team (SIT) for Unit 1, and SIT and Augmented Inspection Team (AIT) for Unit 2. After consultation with NRC headquarters personnel, an SIT was initiated.

Objectives of the Special Inspection:

The SIT will review Constellation's organizational and operator response to the event, equipment and design deficiencies, and the causes for the event and subsequent issues. The team will collect data, as necessary, to refine the existing risk analysis. The team will also assess whether the SIT should be upgraded to an Augmented Inspection Team. Additionally, the team leader will review lessons learned identified during this special inspection and, if appropriate, prepare a feedback form on recommendations for revising the Reactor Oversight Process (ROP) baseline inspection procedures.

To accomplish these objectives, the team will:

1. Develop a complete sequence of events including follow-up actions taken by Constellation.

2. Review and assess the equipment response to the event. This assessment should include an evaluation of the consistency of the equipment response with the plant's design and regulatory requirements. In addition, review and assess the adequacy of any operability assessments, corrective and preventive maintenance, and post maintenance testing.

3. Review and assess operator performance including procedures, logs, communications (internal and external), and emergency plan implementation.

4. Review and assess the effectiveness of Constellation's response to this event. This includes overall organizational response, failure modes and effect analysis developed for the equipment challenges, causal analyses conducted, and interim and proposed longer term corrective actions taken.

5. Evaluate Constellation's application of pertinent industry operating experience and evaluation of potential precursors, including the effectiveness of any actions taken in response to the operating experience or precursors; and

6. Collect any data necessary to refine the existing risk analysis and document the final risk analysis in the SIT report.

Guidance:

Inspection Procedure 93812, "Special Inspection", provides additional guidance to be used by the Special Inspection Team. Team duties will be as described in Inspection Procedure 93812. The inspection should emphasize fact-finding in its review of the circumstances surrounding the event. It is not the responsibility of the team to examine the regulatory process. Safety concerns identified that are not directly related to the event should be reported to the Region I office for appropriate action.

The team will conduct an entrance meeting and begin the inspection on February 22, 2010. While on site, the team Leader will provide daily briefings to Region I management, who will coordinate with the Office of Nuclear Reactor Regulation, to ensure that all other parties are kept informed. A report documenting the results of the inspection will be issued within 45 days following the final exit meeting for the inspection.

This Charter may be modified should the team develop significant new information that warrants review.

DETAILED SEQUENCE OF EVENTS
February 18, 2010 Dual Unit Trip with Complications

The sequence of events was constructed by the team from review of Control Room Narrative Logs, corrective action program condition reports, post transient review report, process plant computer (PPC) data (alarm message file and plant parameter graphs) and plant personnel interviews. The sequence of events is listed separately by Unit 1 and Unit 2.

UNIT 1 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
02/18/2010		
08:24:25:225	0.000 sec	A phase to ground fault occurs on the 13 kV supply line to Unit 1 Reactor Coolant Pump (RCP) 12B Motor, upstream of 12B RCP Breaker 252-14P02, which is already open (normal lineup).
08:24:25:225	0.000 sec	RCP 12B Breaker 252-14P01 trips open on differential overcurrent relay actuation, stopping 12B RCP.
08:24:27:251	2.026 sec	Feeder Breaker 252-2104 to 13 kV Service Bus 21 trips open, de-energizing Unit 2 Non-vital balance of plant, Unit 2 Vital 4 kV Bus 24 and Unit 1 Vital 4 kV Bus 14.
08:24:27:421	2.196 sec	208/120 V/AC Bus 12 de-energizes, resulting in isolation of the Unit 1 RCS letdown flowpath in the Chemical and Volume Control System (CVCS).
08:24:28:803	3.578 sec	13 kV Service Bus 22 Supply Breaker 252-2202 to Unit 1 RCPs trips open. Unit 1 RCPs are not affected as they are aligned to their normal power supply from 13 kV Station Service Transformer P-13000-1 through 13 kV Service Bus 12.
08:24:28:781	3.556 sec	500 kV Switchyard Red Bus Isolation Breaker 552-41 trips open.
08:24:28:783	3.558 sec	500 kV Switchyard Red Bus Isolation Breakers 552-21 and 552-61 trip open, completing the high side isolation 13 kV Station Service Transformer P-13000-2.
08:24:29:110	3.885 sec	Unit 1 automatic reactor trip on reactor coolant low flow signal from 93% initial reactor power level. 3 of 4 Unit 1 reactor coolant pumps are still operating.
08:24:29:146	3.921 sec	Unit 1 reactor trip breakers open.
08:24:29:417	4.192 sec	Unit 1 turbine trip.
08:24:29:423	4.198 sec	Undervoltage signal actuates on Unit 1 4 kV Vital Bus 14, initiating the 1B Emergency Diesel Generator start sequence.
08:24:29:948	4.723 sec	Unit 1 4 kV Vital Bus 14 Normal Feeder Breaker 152-1414 trips open.
08:24:33:818	8.593 sec	13 kV Service Bus 21 Supply Breaker 252-2103 to Transformer U-4000-22 opens.
08:24:33:818	8.593 sec	13 kV Service Bus 21 Supply Breaker 252-2102 to Transformer U-4000-21 opens.
08:24:33:819	8.594 sec	13 kV Service Bus 21 Supply Breaker 252-2101 to Transformer U-4000-23 opens.
08:24:36:101	10.876 sec	Emergency Diesel Generator 1B reaches 810 rpm.
08:24:37:255	12.030 sec	Emergency Diesel Generator 1B Output Breaker 152-1403 to 4 kV Vital Bus 14 closes.
08:24:37:267	12.042 sec	Shutdown Sequencer on 4 kV Vital Bus 14 actuates, to re-start bus loads.

UNIT 1 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
08:24:37:748	12.523 sec	208/120 V/AC Bus 12 re-energizes.
08:24:37:774	12.549 sec	Undervoltage signal clears on Unit 1 4 kV Vital Bus 14.
08:24:42:015	16.790 sec	Reactor Operator backs up the automatic reactor trip signal by depressing manual reactor trip pushbuttons.
08:24:55	30 sec	Crew enters EOP-0, Post-Trip Immediate Actions
08:26:35	2.17 min	Component Cooling Pump 11 is manually started. Component Cooling system pressure and flow are restored.
08:31	7 min	Charging Pump 13 re-started.
08:40	16 min	Crew exits EOP-0 and enters EOP-1, Reactor Trip.
09:00	36 min	Pressurizer level out of EOP control band high, >180 inches.
09:02	38 min	Charging Pump 11 stopped.
09:12	48 min	Operators attempt to restore CVCS letdown (1st attempt). Charging Pump 11 started. Letdown Isolations CVC-515 and 516 opened.
09:20	56 min	Charging Pump 11 stopped.
09:37	73 min	Letdown Isolation Valves CVC-515 and 516 closed.
10:41	2.28 hrs	Pressurizer level returns within EOP control band, <180 inches.
10:44	2.33 hrs	Operators attempt to restore CVCS letdown (2nd attempt). Charging Pump 11 started. Letdown Isolations CVC-515 and 516 opened.
10:47	2.38 hrs	Pressurizer level out of EOP control band high, >180 inches.
11:07	2.72 hrs	Charging Pump 11 stopped.
11:28	3.07 hrs	Letdown Isolation Valves CVC-515 and 516 closed.
11:39	3.25 hrs	Operators attempt to restore CVCS letdown (3rd attempt). Charging Pump 11 started. Letdown Isolations CVC-515 and 516 opened.
11:47	3.38 hrs	Completed 4 hr report to NRC, as required per 10CFR50.72.
11:50	3.43 hrs	Charging Pump 11 stopped.
11:52	3.47 hrs	Letdown Isolation Valves CVC-515 and 516 closed.
12:02	3.63 hrs	Pressurizer level above Tech Spec limit, >225 inches.
12:07	3.72 hrs	Pressurizer level returns within Tech Spec limit, <225 inches.
12:07	3.72 hrs	Completed STP-O-90-1, AC Sources and Onsite Power Distribution Systems 7 Day Operability Verification.
12:11	3.78 hrs	Disconnects for 500 kV Switchyard Breaker 552-21 are opened.
12:14	3.83 hrs	Disconnects for 500 kV Switchyard Breaker 552-61 are opened.
12:15	3.85 hrs	Disconnects for 500 kV Switchyard Breaker 552-23 are opened.
12:17	3.88 hrs	Disconnects for 500 kV Switchyard Breaker 552-22 are opened.
12:18	3.90 hrs	Disconnects for 500 kV Switchyard Breaker 552-63 are opened.
13:06	4.70 hrs	Pressurizer level returns within EOP control band, <180 inches.
13:09	4.75 hrs	Operators attempt to restore CVCS letdown (4th attempt). Charging Pump 11 started. Commenced RCS boration from 11 Boric Acid Tank.
13:11	4.77 hrs	Pressurizer level out of EOP control band high, >180 inches.
13:17	4.88 hrs	Letdown Isolations CVC-515 and 516 opened. CVCS letdown restored. Letdown Excess Flow Check Valve 1-CVC-343-CV opened on 4th letdown restoration attempt.
13:30	5.10 hrs	Pressurizer level returns within EOP control band, <180 inches.

UNIT 1 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
13:38	5.23 hrs	Crew exits EOP-1 and enters OP-5, Plant Shutdown From Hot Standby to Cold Shutdown.
13:46	5.37 hrs	Boration stopped, charging suction from VCT to lower VCT level.
13:58	5.57 hrs	Boration re-commenced from 11 Boric Acid Tank.
14:07	5.72 hrs	4 kV Vital Bus 14 Alternate Feeder Breaker 152-1401 closed.
14:13	5.82 hrs	Emergency Diesel Generator 1B Output Breaker 152-1403 to 4 kV Vital Bus 14 opened.
14:15	5.85 hrs	Emergency Diesel Generator 1B shutdown.
14:16	5.87 hrs	Boration completed. Approximately 2420 gallons of boric acid injected.
14:37	6.22 hrs	RCS sampled for boron. Concentration at 529 ppm.
16:00	7.6 hrs	RCS sampled for boron. Concentration at 622 ppm.
21:50	13.4 hrs	Disconnects for 500 kV Switchyard Breaker 552-22 closed.
22:00	13.6 hrs	500 kV Switchyard Breaker 552-22 closed.
22:01	13.6 hrs	Disconnects for 500 kV Switchyard Breaker 552-23 closed.
22:07	13.7 hrs	500 kV Switchyard Breaker 552-23 closed.
02/19/2010		
12:01	27.6 hrs	SMECO now credited to 4 kV Bus 24.
02/20/2010		
17:05	56 hrs	Started 12B RCP.
19:20	59 hrs	Commenced RCS cooldown to MODE 5 per OP-5.
02/21/2010		
05:38	69 hrs	Unit 1 in MODE 5, RCS temperature < 200°F.
05:50	69.5 hrs	Divorced from SMECO, re-energized 500 kV Red Bus.

UNIT 2 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
02/18/2010		
08:24:25:225	0.000 sec	A phase to ground fault occurs on the 13 kV supply line to Unit 1 Reactor Coolant Pump (RCP) 12B Motor, upstream of 12B RCP Breaker 252-14P02, which is already open (normal lineup).
08:24:25:225	0.000 sec	RCP 12B Breaker 252-14P01 trips open on differential overcurrent relay actuation, stopping 12B RCP.
08:24:27:251	2.026 sec	Feeder Breaker 252-2104 to 13 kV Service Bus 21 trips open, de-energizing Unit 2 Non-vital balance of plant, Unit 2 Vital 4 kV Bus 24 and Unit 1 Vital 4 kV Bus 14.
08:24:27:478	2.253 sec	208/120 V/AC Bus 22 de-energizes, resulting in isolation of the Unit 2 RCS letdown flowpath in the Chemical and Volume Control System (CVCS).
08:24:28:803	3.578 sec	13 kV Service Bus 22 Supply Breaker 252-2202 to Unit 1 RCPs trips open. Unit 1 RCPs are not affected as they are aligned to their normal power supply from 13 kV Station Service Transformer P-13000-1 through 13 kV Service Bus 12.
08:24:28:781	3.556 sec	500 kV Switchyard Red Bus Isolation Breaker 552-41 trips open.

UNIT 2 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
08:24:28:783	3.558 sec	500 kV Switchyard Red Bus Isolation Breakers 552-21 and 552-61 trip open, completing the high side isolation 13 kV Station Service Transformer P-13000-2.
08:24:29:451	4.226 sec	Undervoltage signal actuates on Unit 2 4 kV Vital Bus 24, initiating the 2B Emergency Diesel Generator start sequence.
08:24:29:511	4.286 sec	Unit 2 4 kV Vital Bus 24 Normal Feeder Breaker 152-2401 trips open.
08:24:29:788	4.563 sec	Unit 2 automatic reactor trip on reactor coolant low flow signal from 100% initial reactor power level. All Unit 2 reactor coolant pumps have stopped.
08:24:29:827	4.602 sec	Unit 2 reactor trip breakers open.
08:24:30:019	4.794 sec	Unit 2 turbine trip.
08:24:32:122	6.897 sec	Emergency Diesel Generator 2B reaches 250 rpm.
08:24:33:818	8.593 sec	13 kV Service Bus 21 Supply Breaker 252-2103 to Transformer U-4000-22 opens.
08:24:33:818	8.593 sec	13 kV Service Bus 21 Supply Breaker 252-2102 to Transformer U-4000-21 opens.
08:24:33:819	8.594 sec	13 kV Service Bus 21 Supply Breaker 252-2101 to Transformer U-4000-23 opens.
08:24:33:889	8.664 sec	4 kV Non-Vital Bus 22 Feeder Breaker 152-2201 opens.
08:24:33:909	8.684 sec	4 kV Non-Vital Bus 23 Feeder Breaker 152-2311 opens.
08:24:35:988	10.763 sec	Emergency Diesel Generator 2B reaches 810 rpm.
08:24:37:306	12.081 sec	Emergency Diesel Generator 2B Output Breaker 152-2403 to 4 kV Vital Bus 24 closes.
08:24:37:785	12.560 sec	208/120 V/AC Bus 22 re-energizes.
08:24:37:887	12.662 sec	Undervoltage signal clears on Unit 2 4 kV Vital Bus 24.
08:24:45:155	19.930 sec	Emergency Diesel Generator 2B trips.
08:24:45:185	19.960 sec	Emergency Diesel Generator 2B Output Breaker 152-2403 to 4 kV Vital Bus 24 opens.
08:24:45:320	20.095 sec	208/120 V/AC Bus 22 de-energizes.
08:24:47:315	22.090 sec	Undervoltage signal actuates on Unit 2 4 kV Vital Bus 24.
08:24:55:133	29.908 sec	21 and 22 Steam Generator Feed Pumps low suction pressure trip.
08:24:56:335	31.110 sec	Reactor Operator backs up the automatic reactor trip signal by depressing manual reactor trip pushbuttons.
08:24:55	30 sec	Crew enters EOP-0, Post-Trip Immediate Actions
08:26	2 min	Commenced boration because of loss of power to rod position indication. Aligned gravity feed flowpath from boric acid storage tanks to charging pump suction through 2-MOV-508 and 2-MOV-509.
08:32	8 min	Manually closed 2-MS-343, Main Steam (MS) Isolation to 22 Moisture Separator Reheater (MSR) as alternate action because 2-MS-4019-CV, MS to 22 MSR 2nd Stage failed to close.
08:33	9 min	Steam-driven AFW Pump 21 started to maintain SG heat sink, feeding approximately 150 gpm to each steam generator.
08:34	10 min	2Y10 tied to 2Y09. Power restored to 2Y10.
08:38	14 min	Crew exits EOP-0 and enters EOP-2, Loss of Offsite Power / Loss of Forced Circulation
08:47	23 min	Report of smoke and acrid odor, vicinity of MCC-207

UNIT 2 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
08:53	29 min	Unit 2 main steam isolation valves closed.
08:57	33 min	4 kV Vital Bus 24 Alternate Feeder Breaker 152-2414 closed. Shutdown sequencer is manually initiated per EOP Attachment 16. The undervoltage signal clears on Unit 2 4 kV Vital Bus 24.
09:00	36 min	Restored Unit 2 CVCS letdown.
09:08	44 min	Low condenser vacuum.
09:10	46 min	VCT Outlet MOV-501 opened. Boration stopped. Approximately 1936 gallons of boric acid injected.
09:20	56 min	Electricians report acrid odor coming from closed 4 kV Non-vital Bus 23 Supply Breaker 152-2501 (cause later diagnosed as a burnt breaker trip coil).
10:46	2.37 hrs	Chemistry samples RCS for boron concentration.
11:00	2.60 hrs	Completed verification of required shutdown margin per NEOP-301 Attachment 3. Required concentration determined to be 1297 ppm.
11:17	2.88 hrs	Started 23 AFW Pump (motor-driven) and stopped 21 AFW Pump (turbine-driven).
11:18	2.90 hrs	Crew exits EOP-2 and enters OP-5, Plant Shutdown From Hot Standby to Cold Shutdown.
11:30	3.10 hrs	Chemistry reports RCS boron 1479 ppm. Initial concentration was 1129 ppm prior to the event.
11:47	3.38 hrs	Completed 4 hr report to NRC, as required per 10CFR50.72.
12:11	3.78 hrs	Disconnects for 500 kV Switchyard Breaker 552-21 are opened.
12:14	3.83 hrs	Disconnects for 500 kV Switchyard Breaker 552-61 are opened.
12:15	3.85 hrs	Disconnects for 500 kV Switchyard Breaker 552-23 are opened.
12:17	3.88 hrs	Disconnects for 500 kV Switchyard Breaker 552-22 are opened.
12:18	3.90 hrs	Disconnects for 500 kV Switchyard Breaker 552-63 are opened.
12:55	4.52 hrs	Completed STP-O-90-2, AC Sources and Onsite Power Distribution Systems 7 Day Operability Verification. This was a missed action requirement of TS 3.8.1, required to be completed within 1 hour of the event.
13:30	5.10 hrs	Commenced RCS Cooldown # 87 using Natural Circulation to target temperature of 445°F per OP-5 to protect RCP seals.
14:45	6.35 hrs	Stopped RCS Cooldown # 87 based on decision to start two RCPs and go on forced circulation. RCS temperature at 505°F.
17:13	8.82 hrs	Started 21B and 22A RCPs. Forced RCS circulation restored.
21:50	13.43 hrs	Disconnects for 500 kV Switchyard Breaker 552-22 closed.
22:00	13.60 hrs	500 kV Switchyard Breaker 552-22 closed.
22:01	13.62 hrs	Disconnects for 500 kV Switchyard Breaker 552-23 closed.
22:07	13.72 hrs	500 kV Switchyard Breaker 552-23 closed.
02/19/2010		
00:29		Started 21 Condensate Pump
02:56		Started 21 Circulating Water Pump
06:00		Restored Gland Sealing Steam
07:10		Performed fast speed start test of EDG 2A.
07:37		EDG 2A paralleled to 4 kV Bus 21.
07:49		EDG 2A at full load on 4 kV Bus 21.
10:08		Aligned SMECO to 13 kV Bus 21.

UNIT 2 EVENT TIMELINE		
Clock Time	**Event Time**	**Description**
11:01		Energized U-4000-21 from 13 kV Bus 21 (SMECO feeding).
11:02		Energized U-4000-22 from 13 kV Bus 21 (SMECO feeding).
12:05	27.6 hrs	Two offsite power sources verified OPERABLE with SMECO supplying 13 kV Bus 21 and available to Unit 2 4 kV buses.
12:28		Unloaded EDG 2A.
12:32		Shutdown EDG 2A. Completed 4 hour loaded test run.
13:52		Restored normal power supply alignment for 208/120 Instrument Bus 22 (2Y10). 2Y09 and 2Y10 are un-tied.
02/20/2010		
17:19	57 hrs	Performed fast speed start test of EDG 2B.
17:36		EDG 2B paralleled to 4 kV Bus 24.
17:46		EDG 2B at full load on 4 kV Bus 24.
21:57		Unloaded EDG 2B.
22:02		Shutdown EDG 2B. Completed 4 hour loaded test run.
22:31	62 hrs	EDG 2B declared OPERABLE.
02/21/2010		
04:24		Commenced drawing main condenser vacuum.
05:50	69.5 hrs	Divorced from SMECO, re-energized 500 kV Red Bus.
09:24		Opened 21 and 22 Main Steam Isolation Valves
09:25	73 hrs	Recommenced RCS Cooldown # 87 to MODE 5 per OP-5.
17:16	81 hrs	Unit 2 in MODE 4, RCS temperature < 350°F.
20:12	84 hrs	Stopped RCS cooldown to degas RCS.
02/22/2010		
01:30	89 hrs	Recommenced RCS cooldown.
05:00	92.6 hrs	Unit 2 in MODE 5, RCS temperature < 200°F.