December 22, 2005

Mr. M. Nazar
Senior Vice President and
Chief Nuclear Officer
Indiana Michigan Power Company
Nuclear Generation Group
One Cook Place
Bridgman, MI 49106

SUBJECT: D. C. COOK NUCLEAR POWER PLANT, UNIT 2
NRC SPECIAL INSPECTION REPORT 05000316/2005013

Dear Mr. Nazar:

On November 18, 2005, the NRC completed a Special Inspection at your D. C. Cook Nuclear Power Plant to evaluate the facts and circumstances surrounding an event that occurred on November 8, 2005, in which the Unit 2 reactor automatically tripped and both of the Unit 2 AB emergency diesel generator (EDG) output breakers malfunctioned. The enclosed report documents the inspection findings, which were discussed with Mr. J. Jensen and members of your staff.

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

On November 8, 2005, the Unit 2 reactor automatically tripped due to reactor coolant pump bus undervoltage. The undervoltage condition resulted from a rapid loss of excitation on the main generator field, caused by poor brush contact with the exciter slip rings. Following the reactor trip, reactor coolant pump bus power was automatically transferred to off-site power via the reserve auxiliary transformers as expected. The Unit 2 AB EDG started as a result of the undervoltage condition and energized bus T21A; however, the EDG output breaker supplying bus T21B failed to close. A second breaker malfunction occurred about 1 hour and 10 minutes after the reactor trip when the Unit 2 AB EDG output breaker to bus T21A tripped open and then re-closed 23 seconds later. The Unit 2 CD EDG had been removed from service for scheduled maintenance just before the event.

Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Procedure 71153, "Event Followup," and due to the equipment performance problems that occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The inspection was chartered to evaluate the facts and circumstances surrounding the event as well as the actions taken by your staff in response and to evaluate the facts and circumstances surrounding the event as well as the unexpected system performance issues encountered. The inspection focused on: (1) the sequence of events, including a detailed understanding of main generator voltage response; (2) interviews of plant personnel that were involved in the event to aide in the determination of the technical aspects surrounding the reactor trip and plant response; (3) your cause determination and corrective actions for the main generator failure that initiated the event; (4) the loading of the safety-related buses and the operation of associated safety-related breakers following the event; (5) your cause determination and corrective actions for the T21B emergency bus not becoming energized immediately following the reactor trip; (6) your cause determination and corrective actions for the T21A11 breaker trip and re-closure approximately 1 hour and 10 minutes into the event; (7) an evaluation of any plant equipment powered from the safety-related buses that may have been impacted by degraded voltage conditions; and, (8) your overall corrective actions for this event.

The NRC Special Inspection team concluded that this event could have been avoided had effective preventive maintenance been performed on the Unit 2 main generator exciter brushes. While the inspection results indicate that your staff responded appropriately to the event, two EDG output breaker malfunctions challenged operators and complicated the event response.

Your staff took immediate measures to evaluate this event and initiated actions to prevent recurrence. Those actions included the replacement of brushes and brush holders on the Unit 2 main generator exciter, repairs to the Unit 2 main generator exciter slip ring, and verification of proper brush installation on both the Unit 1 and Unit 2 main generators and main generator exciters. Actions to address the breaker malfunctions included replacing an incorrectly installed wire lug on a breaker test switch connection for the T21B4 breaker and additional wiring inspections, replacing a failed relay in the breaker closing circuit for the T21A11 breaker, and functionally testing the currently installed T21B4 breaker.

Your staff had not yet completed its root cause evaluation at the conclusion of this inspection and had not yet formulated other corrective actions in response to this event.

Based on the results of this inspection, two findings of very low safety significance (Green) were identified, one of which involved a violation of NRC requirements. However, because of the very low safety significance and because the associated issues were entered into your corrective action program, the NRC is treating the violation as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the D. C. Cook Nuclear Power Plant.

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

Sincerely,

/RA/

Mark A. Satorius, Director
Division of Reactor Projects

Docket No. 50-316
License No. DPR-74

Enclosure: Inspection Report 05000316/2005013
w/Attachments: 1. Supplemental Information
2. Special Inspection Charter

cc w/encl: J. Jensen, Site Vice President
L. Weber, Plant Manager
G. White, Michigan Public Service Commission
L. Brandon, Michigan Department of Environmental Quality - Waste and Hazardous Materials Division
Emergency Management Division
MI Department of State Police
D. Lochbaum, Union of Concerned Scientists

See Previous Concurrence

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No.:	50-316
License No.:	DPR-74
Report No.:	05000316/2005013
Licensee:	Indiana Michigan Power Company
Facility:	D. C. Cook Nuclear Power Plant, Unit 2
Location:	Bridgman, MI 49106
Dates:	November 9, 2005, through November 18, 2005
Inspectors:	B. Kemker, Senior Resident Inspector C. Brown, Reactor Engineer J. Robbins, Reactor Engineer
Approved by:	C. Lipa, Chief Reactor Projects Branch 4

Enclosure

SUMMARY OF FINDINGS

IR 05000316/2005-013; 11/09/2005-11/18/2005; D. C. Cook Nuclear Power Plant, Unit 2; Special Inspection; Event Response.

The report covered a 2-week period of inspection by the senior resident inspector and regional inspectors. Two Green findings were identified, one of which had an associated Non-Cited Violation (NCV). The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

C Green. The inspectors identified a finding of very low safety significance associated with a self-revealed event. The licensee failed to perform adequate preventive maintenance on the Unit 2 main generator exciter, which led to brush failures, loss of field excitation, and a reactor trip. No violation of regulatory requirements was identified. Immediate corrective actions to address this finding included the replacement of brushes and brush holders on the Unit 2 main generator exciter, repairs to the Unit 2 main generator exciter slip ring, and verification of proper brush installation on both the Unit 1 and Unit 2 main generators and main generator exciters.

This finding was of more than minor safety significance because it was associated with the Equipment Performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations since inadequate preventive maintenance led to the main generator exciter brush failures that caused the reactor trip. Although the event contributed to the likelihood of a reactor trip, the finding is of very low significance because all mitigation systems were available. This finding affected the cross-cutting issue of human performance (resources). (Section 4OA3.3)

Cornerstone: Mitigating Systems

C Green. The inspectors identified a performance deficiency that resulted in a Non-Cited Violation of Technical Specification 3.8.1, with two examples. The licensee failed to perform adequate post maintenance testing after installing a design modification, which resulted in one of the two Unit 2 AB emergency diesel generator (EDG) output breakers (breaker T21B4 supply to bus T21B) failure to automatically close on demand. The Unit 2 AB EDG was rendered inoperable due to the T21B4 breaker malfunction and this resulted in two examples of exceeding Technical Specification allowed outage times.

Immediate corrective actions to address this finding included replacing an incorrectly installed wire lug on a test switch connection and completing additional wiring inspections.

This finding was of more than a minor safety significance because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences since the Unit 2 AB EDG was rendered inoperable, in particular breaker T21B4, for an extended period of time. Although this issue affected the capability of the EDG to provide power to bus T21B following a loss of offsite power event, the Regional Senior Reactor Analyst determined that this finding was of very low safety significance during a Phase 3 Significance Determination Process evaluation because the effect of the unavailability of bus T21B on overall plant risk was not significant. (Section 4OA3.5)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Event

On November 8, 2005, at 3:58 a.m. (EST), the Unit 2 reactor automatically tripped due to reactor coolant pump (RCP) bus undervoltage. The undervoltage condition resulted from a rapid loss of excitation on the main generator field, caused by poor brush contact with the exciter slip rings. Just before the event, the Unit 2 CD emergency diesel generator (EDG) ("A" train) was removed from service for scheduled maintenance. Refer also to the sequence of events time line in Section 4OA3.1.

As a result of the loss of field excitation, under voltage relays sensing voltage on the RCP buses (2A, 2B, 2C and 2D) actuated and generated the reactor trip. At nearly the same instant, undervoltage relays sensing voltage on the "B" train safety buses (T21A and T21B) initiated an EDG start and load shed signal for the "B" safety-related train. The Unit 2 AB EDG started and energized bus T21A; however, bus T21B did not energize as expected. Refer to Figure 1, which depicts the main electrical power distribution for Unit 2.

Following the reactor trip, RCP bus power was automatically transferred, per design, to off-site power via the reserve auxiliary transformers. All four RCPs remained running.

Since the Unit 2 CD EDG was out of service for a planned maintenance activity with its two output breakers racked out, a load shed signal was not developed on the "A" train safety buses (T21C and T21D), so that power to those buses was maintained from the RCP buses (2C and 2D).

The Unit 2 AB EDG was declared inoperable because the EDG output breaker to bus T21B (T21B4) failed to close. The T21B bus remained without power until operators re-energized the bus from reserve feed at 11:02 a.m.

Approximately 1 hour and 10 minutes after the reactor trip, the Unit 2 AB EDG output breaker to bus T21A (T21A11) cycled open and re-closed 23 seconds later. When the breaker opened, a load sequence signal on the T21A bus was initiated so that all loads sequenced onto the bus when the breaker re-closed.

The Unit 2 CD EDG was returned to service and operators declared the engine operable at 6:06 a.m. To address the common mode verification requirement from Technical Specification (TS) 3.8.1, operators started the Unit 2 CD EDG, closed the output breakers, and loaded the EDG later in the evening at 9:54 p.m.

Inspection Scope

Based on the risk and deterministic criteria specified in Management Directive 8.3, "NRC Incident Investigation Program," and Inspection Procedure 71153, "Event Followup," and due to the equipment performance problems that occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection."

The inspection focused on the following charter items:

(1) the sequence of events, including a detailed understanding of main generator voltage response;
(2) interviews of plant personnel that were involved in the event to aide in the determination of the technical aspects surrounding the reactor trip and plant response;
(3) the licensee's cause determination and corrective actions for the main generator failure that initiated the event;
(4) the loading of the safety-related buses and the operation of associated safety-related breakers following the event;
(5) the licensee's cause determination and corrective actions for the T21B emergency bus not becoming energized immediately following the reactor trip;
(6) the licensee's cause determination and corrective actions for the T21A11 breaker trip and re-closure approximately 1 hour and 10 minutes into the event;
(7) an evaluation of any plant equipment powered from the safety-related buses that may have been impacted by degraded voltage conditions; and,
(8) the licensee's overall corrective actions for this event.

4. OTHER ACTIVITIES (OA)

4OA3 Special Inspection (93812)

.1 Sequence of Events

a. Inspection Scope

On November 8, 2005, the Unit 2 reactor automatically tripped due to an RCP bus undervoltage condition. During this event, both of the Unit 2 AB EDG output breakers malfunctioned. The inspectors reviewed selected documents and conducted interviews of plant personnel to determine the sequence of events.

b. Findings and Observations

Introduction

Based upon a review of the licensee's failure investigation process documents, control room logs, plant process computer data, and interviews with plant personnel, the inspectors developed the following sequence of events associated with the event. Several important dates and times, related to a past operability determination for the Unit 2 AB EDG, are included early in the time line before the event occurred.

Discussion

Date and Time	Event Description
October 27, 2005	
8:10 p.m.	Unit 2 AB EDG was inoperable to support installation and testing of a modification in the control room EDG panel. Entered TS 3.8.1 (b) and (c) for an inoperable EDG. During this work, an improperly crimped lug on a conductor to a test switch in the breaker's closing circuit was disturbed so that the breaker would not automatically close following a load shed.
October 28th	
1:16 a.m.	Unit 2 AB EDG declared operable following installation of the modification. Exited TS 3.8.1 (b) and (c). However, unknown to the operators, the EDG was actually not operable because of the failed lug on the test switch.
October 31st	
10:58 p.m.	Unit 2 CD EDG was inoperable to support installation and testing of a modification in the control room EDG panel. Entered TS 3.8.1 (b) and (c) for an inoperable EDG.
November 1st	
11:25 a.m.	Unit 2 CD EDG restored to operable status following installation of the modification. Exited TS 3.8.1 (b) and (c). Total duration was 12 hours, 27 minutes.
November 8th	
2:51 a.m.	Unit 2 is operating at full power. The shift technical advisor verified grid stability via a telephone call to the system load dispatcher in Fort Wayne, Indiana. No abnormalities were noted and weather forecasts were being monitored.
3:05 a.m.	Unit 2 CD EDG removed from service for scheduled maintenance. Entered TS 3.8.1 (b) and (c) for an inoperable EDG.
3:54 a.m.	Voltage oscillations were noted on the Unit 2 main generator. Momentary low voltage alarms and indicator lights illuminated. The shift technical advisor contacted the system load dispatcher to determine if the load dispatcher could account for this observation. The load dispatcher reported that there were no abnormal indications on the power grid.

Date and Time	Event Description
3:58 a.m.	Unit 2 reactor tripped (RxT) on RCP bus under voltage. There was an electrical disturbance just before the trip. Operators observed 600 volt bus voltages lowering before the trip. The following sequence of events was retrieved from the plant process computer. 03:59:01.923 RxT RCP BUS UNDERVOLTAGE 03:59:01.993 RxT BREAKER TRAIN 'A' OPEN 03:59:02.006 RxT BREAKER TRAIN 'B' OPEN 03:59:02.255 RxT BREAKER UNDERVOLTAGE TRAIN 'A' 03:59:02.267 RxT BREAKER UNDERVOLTAGE TRAIN 'B' 03:59:02.327 RxT NIS - POWER RANGE POS/NEG RATE TRIP 03:59:02.598 MAIN GENERATOR MOTORING 03:59:11.777 DIESEL GENERATOR 2AB START (AT SPEED) 03:59:30.144 MAIN GENERATOR BREAKER OPEN The turbine driven auxiliary feed water pump started as expected. The Unit 2 AB EDG started, but failed to pick up loads on the T21B bus. The west centrifugal charging pump was de-energized when the reactor tripped due to load shedding of the T21A and T21B buses.
4:06 a.m.	Operators started the east centrifugal charging pump and restored letdown flow.
4:16 a.m.	Control Room received a report that a security officer observed an electrical flash on the south end of the Unit 2 main generator pilot exciter at the time of the reactor trip.
5:10:03 a.m.	Unit 2 AB EDG output breaker T21A11 opened. Loads on bus T21A shed as expected.
5:10:26 a.m.	Unit 2AB EDG output breaker T21A11 re-closed. Loads sequenced on as expected.
5:55 a.m.	The shift technical advisor contacted the system load dispatcher to determine if any abnormal grid issues were identified after the Unit 2 reactor trip. No abnormalities were noted by the system load dispatcher.
6:06 a.m.	Unit 2 CD EDG declared operable and returned to service. Exited TS 3.8.1 (b) and (c).

Date and Time	Event Description
7:10 a.m.	Licensee made a 10 CFR Part 50.72 notification for the Unit 2 reactor trip and engineered safety features actuations.
9:56 a.m.	Operators positioned the Unit 2 AB EDG output breaker T21B4 control switch in "pull-to-lock."
10:38 a.m.	Operators racked out breaker T21B4.
11:02 a.m.	Operators energized T21B and 21B buses from reserve feed.
11:53 a.m.	Operators closed breaker T21A9 (T21A bus tie breaker) to parallel bus T21A to bus 2A.
11:55 a.m.	Operators opened breaker T21A11 (Unit 2 AB EDG output breaker to bus T21A). Bus T21A is now completely supplied from bus 2A.
11:57 a.m.	Unit 2 AB EDG removed for service and placed in standby.
November 10th	
2:22 a.m.	Unit 2 AB EDG restored to operable status following completion of immediate corrective actions for the T21A11 and T21B4 breaker malfunctions and testing. Exited TS 3.8.1 (b) and (c) after a total duration of 13 days, 6 hours, 12 minutes.

.2 Plant Response Following the Reactor Trip

a. Inspection Scope

The inspectors evaluated the licensee's initial response to the event. Much of this evaluation was based on direct observation by the resident inspectors in the control room following the reactor trip. This evaluation included a review of the control room operators' use of emergency and normal plant operating procedures, identification of degraded plant conditions as a result of the partial loss of power immediately following the reactor trip, initial actions to mitigate the event, and actions to restore power to bus T21B. The inspectors interviewed plant personnel and reviewed applicable portions of the TSs, plant procedures, control room logs, plant process computer data, reactor trip report, and corrective action program documents. The inspection team leader also attended the plant operations review committee meeting that was held before restarting Unit 2, which reviewed the post-trip plant response, apparent cause evaluations, and immediate corrective actions.

b. Findings and Observations

Introduction

No findings of significance were identified.

Discussion

The inspectors observed that even though the loss of power to some plant equipment was a distraction, control room operators effectively controlled and stabilized plant parameters following the reactor trip. The inspectors noted that the shift manager and unit supervisor demonstrated strong command and control throughout the event. In addition, the inspectors noted that operators generally adhered to the licensee's standards for procedure adherence, annunciator response, and three-way communications.

The plant response to the reactor trip was as expected with safety-related systems operating as designed except for the two Unit 2 AB EDG output breaker malfunctions. The turbine driven auxiliary feedwater pump started automatically due to low-low levels in at least two steam generators, an expected result for a reactor trip from full power. The west centrifugal charging pump lost power due to load shedding immediately after the reactor trip, which caused letdown to isolate due to no charging pumps operating. Operators started the east charging pump about 8 minutes later and re-established letdown flow. Component cooling water flow was maintained to the RCP thermal barrier heat exchangers throughout this period.

Some plant equipment was without power due to the loss of power to the T21B bus; however, this did not result in a significant challenge to plant operators. The loss of power primarily affected plant battery chargers that were in service, some turbine building lighting, and several primary plant valves. Operators placed redundant plant equipment in service as needed.

The inspectors had two observations based on their review of the licensee's response to the event:

(1) During review of plant data following the event, the inspectors noted that there were momentary perturbations in main generator reactive load indicated in mega-volt amperes reactive (MVARS) and generator voltage as early as 1½ hours before the event on the control room strip chart recorder. These perturbations were not identified by control room operators. While clearly visible on the chart recorder, these perturbations were not large enough to generate any control room panel alarms. Based on discussions with operations management and several control room operators, the inspectors determined that there was an inconsistent understanding of which control room panels were included in the hourly walkdowns performed by control room operators. The licensee was reviewing its expectations regarding main control room panel monitoring by licensed operators. The licensee entered this observation into its corrective action program as condition report (CR) 05322007.

(2) Both of the Unit 2 CD EDG output breakers had been racked out as part of a clearance order that was in effect just before the event. After removing the clearance order and returning the engine to service at 6:06 a.m. on November 8, operators declared the EDG operable and exited the applicable TS limiting condition for operation (LCO) without starting the engine and closing the breakers to verify that they would function properly. The inspectors questioned the lack of a functional test for the breakers because there were malfunctions of both Unit 2 AB EDG output breakers early in the event that were not yet understood. The inspectors further noted that this was a deviation from the licensee's standard practice and a deviation from the licensee's work management post maintenance testing matrix. The inspectors were concerned that the licensee's decision to declare the Unit 2 CD EDG operable and exit the TS LCO without testing the function of the breakers was done for expediency and was not a conservative operability decision. There was no urgency to declare the EDG operable and exit the TS LCO because the engine became available for use as soon as the clearance order was removed. Later in the evening, at 9:54 p.m., operators started the Unit 2 CD EDG, closed the output breakers, and loaded the engine. The licensee entered this observation into its corrective action program as CR 05325035.

.3 Main Generator Failure Cause Determination and Corrective Actions

a. Inspection Scope

The inspectors reviewed the licensee's apparent cause evaluation and immediate corrective actions for the Unit 2 main generator failure. This review included: interviewing plant personnel, attending licensee meetings evaluating the cause and extent of condition, observing inspections performed by the licensee on the Unit 2 main generator exciter brushes, reviewing preventive maintenance history and procedures, and reviewing relevant corrective action program documents.

b. Findings and Observations

Introduction

The inspectors identified a finding of very low safety significance (Green) associated with a self-revealed event. The licensee failed to perform adequate preventive maintenance on the Unit 2 main generator exciter, which led to brush failures and loss of field excitation and a reactor trip. No violation of regulatory requirements was identified.

Discussion

The licensee examined control room strip chart recorders during the post-event review and found that Unit 2 main generator voltage dropped and MVARS went "IN" (the generator became a load rather than a source) noticeably several times before the reactor trip. About 4 minutes before the reactor trip, operators noted RCP current swings, low voltage lamps lit for all four 600 volt buses, main generator voltage drops, and large MVAR changes. Immediately before and after the event, the shift technical advisor contacted the load dispatcher in Fort Wayne, Indiana to determine whether a problem was present on the grid. The load dispatcher reported that there were no abnormal indications on the grid. Main generator reactive load spiked to greater than 600 MVARS "IN" at the time of the trip, pegging the chart recorder, indicating that the generator was motoring.

When the main generator voltage lowered, the unit auxiliary transformers' voltage was also lowered. Eventually, the voltage dropped low enough to actuate the RCP bus undervoltage reactor protection system trip signal (i.e., 3080 volts, 1/1 logic on 2 buses). Following the trip, RCP bus power was automatically transferred to off-site power via the reserve auxiliary transformers. All four RCPs remained running.

Arcing was observed by a security officer at the Unit 2 main generator exciter. External scorching and soot marks were present. The Unit 2 control room generator field ground alarm came in and the 64-GF1 relay flag was found up, but the exciter field ground alarm and 64-AF-1 flag did not come in. The licensee subsequently performed resistance to ground testing of the generator field on November 9th with satisfactory results.

Following the trip, a number of main generator exciter brushes were found to have been damaged. Several had apparently been in poor contact with the slip rings, causing other brushes to carry more current and therefore heat up, eventually to the point of failure. At full power, the failure of one brush would cause all of the remaining brushes to exceed their continuous current rating. The licensee's apparent cause evaluation concluded that the exciter brush failure was due to ineffective preventive maintenance. The preventive maintenance activity did not provide clear guidance on when to replace brushes, did not require documenting which brushes were replaced for tracking purposes, did not provide criteria for acceptable spring tension, and did not provide guidance on brush orientation.

On the Unit 2 main generator exciter there are 10 negative side brushes and 10 positive side brushes. Inspection of the brushes revealed damage to the negative brushes, brush holders, and the slip ring. The brush holders are brass and one of them had a portion melted away and all of them showed signs of discoloration caused by overheating. One of the negative side brushes was not moving freely in the brush holder and the brush was not in contact with the slip ring. Evidence supporting this was grooves in the side of the brush that lined up with some burrs inside the brush holder and the end of the brush still had the factory machining marks on it. Another brush holder spring was significantly relaxed such that it did not apply the appropriate force on the brush to hold it against the slip ring.

There were two other negative side brushes that were worn down significantly and may not have been making good contact with the slip ring. With these four brushes not carrying their portion of the current, the other brushes would have had to pick up the difference. The extra current caused extra heat to be generated causing one of the brush holders to melt. The spatter from the melting brush holder could have caused damage to the rotating slip ring, which in turn damaged some of the other brushes, leading to the failure.

The licensee's preventive maintenance activity for these brushes directed maintenance craftsmen to replace two brushes any time one brush needed replacement; however, there was no tracking to ensure that all the brushes were replaced on a rotating basis. With the existing preventive maintenance activity, the same two brushes could be replaced each time. The guidance on the acceptable brush length was vague and relied too much on craft skill and knowledge as to when a brush needed to be replaced. The two brushes that were found to be most worn were on the lower half of the shaft and were the most difficult to see when they are in place.

The licensee examined the positive side brushes and all were found in good condition, but two of the brushes were found to be installed incorrectly, with the bevel on the top of the brush reversed in the holder. The bevel is designed so the spring pushes the brush down and to the side of the holder going with the rotation of the shaft. This did not appear to have any impact on these brushes, but this may cause the brushes to chatter in the holders. This chatter would increase as the brushes wore down and became shorter with less engagement in the holders. The negative brushes were removed from the holders without documenting if they were installed correctly because this was not initially considered by the licensee to be a critical inspection point. However, since two of the positive side brushes were installed incorrectly, it was possible that some of the negative brushes had also been installed incorrectly.

The inspectors thoroughly examined the licensee's apparent cause evaluation and concluded that the evaluation was sufficiently thorough and that corresponding immediate corrective actions appropriately addressed the cause.

Immediate corrective actions implemented to address the inadequate preventive maintenance and brush failures included the following:

(1) replacement of the brushes and brush holders on the Unit 2 main generator exciter;

(2) repairs to the Unit 2 main generator exciter slip ring; and
(3) verification of proper brush installation on both the Unit 1 and Unit 2 main generators and main generator exciters.

The licensee had not yet completed its root cause evaluation at the conclusion of this inspection and had not yet formulated other corrective actions in response to this event. The root cause evaluation results and the long term correction actions will be considered as samples in subsequent problem identification and resolution inspections.

Analysis

The inspectors determined that the inadequate preventive maintenance on the main generator exciter brushes, which resulted in the Unit 2 reactor trip, was a licensee performance deficiency warranting a significance evaluation. The inspectors assessed this finding using the Significance Determination Process (SDP). The inspectors reviewed the samples of minor issues in Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions during power operations since inadequate preventive maintenance led to the main generator exciter brush failures that caused the reactor trip. The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and determined that this finding was a licensee performance deficiency of very low safety significance (Green) because the finding: (1) did not contribute to the likelihood of a primary or secondary system loss-of-coolant-accident initiator, (2) did not contribute to both the likelihood of a reactor trip AND the likelihood that mitigation equipment or functions would not be available, and (3) did not increase the likelihood of a fire or internal/external flooding event.

The inspectors also concluded that this finding affected the cross-cutting issue of human performance (resources). Specifically, items that would support the performance of adequate preventive maintenance on the main generator exciter such as complete and accurate procedures, craft skills, and craft training were inadequate.

Enforcement

No violation of regulatory requirements was identified. This issue is considered to be a finding (FIN 05000316/2005013-01). The licensee entered this finding into its corrective action program as CR 05312011.

.4 Loading of the Safety-Related Buses and the Operation of Associated Safety-related Breakers Following the Event

a. Inspection Scope

The inspectors evaluated the response of the Unit 2 safety-related buses and breakers in response to the event against the expected response based on the plant design. This evaluation included a review of automatic actions to unload the safety-related buses, start the EDGs, close the EDG output breakers, and sequence the emergency loads back onto the safety-related buses. This evaluation included a review of the licensee's identification of the degraded condition, initial actions to mitigate the event, and initial actions to restore power to bus T21B. The inspectors interviewed plant personnel and reviewed the plant TSs, Updated Final Safety Analysis Report, selected drawings and schematics, and corrective action program documents.

b. Findings and Observations

Introduction

No findings of significance were identified.

Discussion

The inspectors reviewed the sequence of loading for the safety-related buses and concluded that the plant response was as expected for the conditions that were present during the event. Immediately following the reactor trip, RCP bus power was automatically transferred (fast transfer design feature) to off-site power via the reserve auxiliary transformers and all four RCPs remained running. Undervoltage relays on the "B" train safety buses (T21A and T21B) actuated as expected and initiated an EDG start and load shed signal for the "B" safety-related train. The Unit 2 AB EDG started and energized bus T21A as expected. The T21B bus should have energized, but did not due to the T21B4 breaker malfunction. The opening and re-closing of the T21A11 breaker about 1 hour and 10 minutes into the event was also an unexpected occurrence. The two breaker malfunctions are discussed in more detail in Sections 4OA3.5 and 4OA3.6.

With the Unit 2 CD EDG out of service and the EDG output breakers racked out, there was no load shed function for the "A" train (T21C and T21D) buses and those safety buses continued to receive power from the RCP buses (2C and 2D) regardless of the voltage condition on the 4 kilovolt buses, unless the degraded bus voltage relays picked up. The degraded bus voltage relays did not actuate because this was a very fast voltage transient (< 1 second down ramp) and the degraded bus voltage relays have about a 2-minute time delay.

.5 Breaker T21B4 Malfunction Cause Determination and Corrective Actions

a. Inspection Scope

The inspectors attended licensee meetings, interviewed plant personnel, reviewed maintenance activities, and reviewed applicable procedures and corrective action program documents.

b. Findings and Observations

Introduction

The licensee failed to perform adequate post maintenance testing after installing a design modification, which resulted in one of the two Unit 2 AB EDG output breakers (breaker T21B4 supply to bus T21B) failing to automatically close on demand. As a result, the inspectors identified a Non-Cited Violation of TS 3.8.1, with two examples. The Unit 2 AB EDG was rendered inoperable due to the T21B4 breaker malfunction and this resulted in two examples of exceeding TS allowed outage times.

Discussion

During the event, circuit breaker T21B4 failed to automatically close after the Unit 2 AB EDG started and came up to speed and voltage. Operators did not attempt to manually close the breaker, choosing instead to quarantine it to investigate the failure to close. During the licensee's investigation, operators removed breaker T21B4 from service and replaced it with a spare breaker to allow the breaker to be tested using current plant preventive maintenance procedures. No abnormal conditions were observed during the testing. Additional inspection of the breaker by maintenance craftsmen identified a higher than expected resistance across a contact (LS-A) within the breaker's control circuitry (breaker closing springs fully charged). However, the higher than expected resistance was determined not to be the cause for T21B4 failing to close because the breaker had previously operated successfully four other times during Unit 2 AB EDG monthly testing after it was placed in service on June 28, 2005.

The licensee then expanded the investigation to wiring checks on the breaker operating circuitry. These investigations determined that the failure was caused by an open circuit condition at an improperly crimped lug to test switch number 3 on the T21B4 test switch assembly (used to isolate relays for test and calibration without affecting other components). The improper lug installation had apparently existed from initial plant construction without failure. During a recent design modification installation, electricians tie-wrapped newly installed and existing conductors for the T21B4 breaker test switch together. The tie-wrap immediately adjacent to the number 3 test switch was apparently tightened from within the radius of the wire bend to the lug, causing the wire to be pulled and creating an open circuit condition. The open circuit at this connection caused the breaker's automatic close after load-shed to fail.

The inspectors determined that the T21B4 breaker had not been operated since the modification work on October 27th; however, manually closing the breaker would not have revealed the failed lug connection. Following the installation of the design modification, only specific post maintenance testing requirements intended to reveal if any existing wires had been damaged or displaced would have discovered the open circuit condition. Once the design modification post maintenance testing was completed, only an actual need or test operation of the automatic close after load-shed function would have revealed the open circuit condition. The next test of this circuit was scheduled for the next refueling outage.

The inspectors identified during their review of the sequence of events, that the total time of inoperability for the Unit 2 AB EDG was 13 days, 6 hours, and 12 minutes. This exceeded the TS allowed outage time for a single EDG. The Unit 2 CD EDG was also inoperable to support the same design modification on October 31st and November 1st. The total time of inoperability for the Unit 2 CD EDG was 12 hours and 27 minutes. During this latter period of time, both Unit 2 EDGs were inoperable for a period greater than the TS allowed outage time for two inoperable EDGs.

The inspectors thoroughly examined the licensee's preliminary apparent cause evaluation and concluded that the licensee had not neglected any likely factors. The inspectors concluded that the evaluation was sufficiently thorough and that corresponding immediate corrective actions appropriately addressed the cause.

Immediate corrective actions implemented to address the inadequate post maintenance testing and improperly crimped wire lug included the following:

(1) replacement of the incorrectly installed wire lug,
(2) wiring inspections on all wiring installed by the design modification,
(3) inspections of the test switch connections for all EDG output breakers, and
(4) functional testing of the currently installed T21B4 breaker under the functional testing plan discussed in Section 4OA3.6 below for relay 62-2X-DGAB.

The licensee had not yet completed its final cause evaluation at the conclusion of this inspection and had not yet formulated other corrective actions in response to this event. The root cause results and long term corrective actions will be considered as samples in subsequent problem identification and resolution inspections.

Analysis

The inspectors determined that failing to specify adequate work controls, inspection, and post maintenance testing in the design modification package sufficient to prevent introducing this new failure in the adjacent wiring was a performance deficiency. The inspectors assessed this finding using the SDP. The inspectors reviewed the samples of minor issues in IMC 0612, "Power Reactor Inspection Reports," Appendix E, "Examples of Minor Issues," and determined that there were no examples related to this issue. Consistent with the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," the inspectors determined that the finding was of more than minor significance because this issue was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences since inadequate post maintenance testing led to restoring the Unit 2 AB EDG to service without verifying that the T21B4 breaker would function as designed.

Phase 1 Assessment

The inspectors performed a Phase 1 SDP review of this finding using the guidance provided in IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." In accordance with the "SDP Phase 1 Screening Worksheet for IE [Initiating Events], MS [Mitigating Systems], and B [Barrier Integrity] Cornerstones," the inspectors determined that since Unit 2 was not shut down before exceeding the 72-hour TS allowed outage time for the Unit 2 AB EDG, the finding represented an actual loss of safety function of a single train of safety-related equipment for greater than its TS allowed outage time and a Phase 2 SDP evaluation was warranted. The inspectors noted that although a TS amendment increasing the single EDG allowed outage time to 14 days was recently approved, it was not in effect at the time of the event.

Phase 2 Assessment

The inspectors utilized the "Loss of Offsite Power" and the "Loss of Offsite Power with Loss of Emergency AC Bus Train B or the Associated EDG (LEAC)" Phase 2 SDP Worksheets and solved only those sequences that involved the EDG with a duration of 3-30 days. Based on the results of the SDP worksheets, the inspectors determined that the finding was potentially of low to moderate safety significance (White). The regional senior reactor analyst (SRA) reviewed these results and determined that an SDP Phase 3 assessment was necessary to refine the risk characterization for several reasons, including the fact that the failure was associated with Unit 2 AB EDG output breaker T21B4 and not the EDG itself. The Phase 3 assessment was also necessary because the EDG SDP worksheet results were conservative since the results represent an inoperable EDG for 30 days (720 hours) as opposed to the T21B4 EDG output breaker being inoperable for about 320 hours.

Phase 3 Assessment

Internal Events - The SRA performed the risk evaluation using the D.C. Cook Standardized Plant Analysis Risk (SPAR) Model, Level 1, Revision 3P, Change 3.21, created October 2005. The SPAR model does not model failure of bus T21B, which is fed by EDG output breaker T21B4, but does model bus T21A, which is fed by the other output breaker (T21A11) associated with Unit 2 AB EDG. Because bus T21A carries 4 kilovolt safety-related loads, the SRA determined that this risk would bound the risk of failure of bus T21B. The SRA ran the SPAR model assuming failure of bus T21A for 320 hours and obtained a change in core damage frequency (ΔCDF) of 3.1E-8 (Green). The dominant sequence involved a loss of offsite power, failure of emergency power, failure to recover offsite power in 4 hours, and failure to recover the EDGs in 4 hours.

The SRA also performed a hand calculation using data supplied by the licensee in its analysis (see below). The CDF value per year for bus T21B out of service given the Unit 2 AB EDG inoperable is 3.2E-5. The base CDF is 2.9E-5. Using an exposure time of 320 hours, the SRA calculated a ΔCDF of 1.1E-7 (Green).

External Events - External events such as seismic, fire, and flooding are not significant contributors to the risk associated with this finding. For seismic and fire scenarios, the CDF is in the range of 1E-4 to 1E-5 per year. Multiplication of this value by the exposure time of about 2 weeks (i.e., 14/365), lowers the risk by a factor of about 380. Other available mitigating equipment, such as the opposite EDG, would lower the risk further such that contribution due to seismic activity and fire is insignificant. Flooding risk is incorporated into the licensee's PRA model and was part of the assessment performed by the licensee. The SRA's review of the licensee's risk assessment is discussed below.

Large Early Release Frequency (LERF) - Using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process," the SRA determined that this was a Type "A" finding for a pressurized water reactor ice condenser containment. Using Table 5.2, the SRA did not identify any impact on containment performance as a result of this finding. The attributes considered in Table 5.2 were inter-system loss of coolant accidents, steam generator tube ruptures, and station blackouts events. None of these scenarios was impacted. The SRA concluded that the ΔLERF was negligible and did not contribute to the risk associated with this finding.

Licensee's Analysis: The licensee performed a calculation using its Safety Monitor Software to estimate the risk impact of the condition given the plant configuration that existed when Unit 2 AB EDG output breaker T21B failed to close. The licensee determined that the breaker failed to close because a modification in a control room panel disturbed a pre-existing inadequate wire connection and caused a connecting wire to become detached. The calculation did not consider external events such as seismic and fire due to low event probabilities and low CDF contributions.

Important assumptions in the licensee's calculation were that the supplemental diesel generators were unavailable, and that breaker T21B4 assumed to be completely failed. The licensee ran a sensitivity case for comparison that credited the capability for the operator to manually close the breaker. This case assumed an operator failure probability of 1E-1.

The licensee's total ΔCDF for a base case that assumes that breaker T21B4 was unavailable, both automatically and manually, from the time that the modification was installed until the Unit 2 AB EDG and its output breaker T21B4 were declared operable, was 5.5E-7 (Green). The total ΔCDF for the sensitivity case in which only the automatic operation of breaker T21B4 was unavailable from the time that the modification was installed until the Unit 2 AB EDG and its output breaker T21B4 were declared operable was 4E-7 (Green).

Significance Determination Conclusion: The SRA concluded that the total ΔCDF considering internal events, external events, and LERF was in the range of 1E-7 to 1E-8 range (Green).

Enforcement

As a result of the performance deficiency described above, the inspectors identified an NCV, with two examples.

Unit 2 TS 3.8.1, Conditions B and G, required, in part, that a single inoperable EDG be restored to operable status within 72 hours or enter Mode 3 with in 6 hours. Contrary to the above, on October 27, 2005, at 8:10 p.m., the Unit 2 AB EDG was rendered inoperable to install a design modification. The total time of inoperability for the Unit 2 AB EDG was 13 days, 6 hours, and 12 minutes as a result of the performance deficiency described above. The licensee failed to restore the EDG to operable status within 72 hours or enter Mode 3 within 6 hours. This is a violation of TS 3.8.1, Conditions B and G. Compliance with the above TS requirements was restored when Unit 2 entered Mode 3 on November 8, 2005, at 3:58 a.m. The Unit 2 AB EDG was returned to operable status on November 10, 2005, at 2:22 a.m.

Unit 2 TS 3.8.1, Conditions F and G, required, in part, that with two inoperable EDGs, restore one EDG to operable status within 2 hours or enter Mode 3 in 6 hours. Contrary to the above, on October 31, 2005, at 10:58 p.m., the Unit 2 CD EDG was rendered inoperable to support the same design modification. During this period of time, both of the Unit 2 EDGs were inoperable for a period of 12 hours and 27 minutes. The licensee failed to restore one EDG to operable status within 2 hours or enter Mode 3 in 6 hours. This is a violation of TS 3.8.1, Conditions F and G. Compliance with the above TS requirements was restored when the Unit 2 CD EDG was returned to operable status on November 1, 2005, at 11:25 a.m.

Because of the very low safety significance, the licensee's failure to comply with the requirements of TS 3.8.1 is being treated as a Non-Cited Violation consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000316/2005013-02). The licensee entered this violation into its corrective action program as CR 05312006.

.6 Breaker T21A11 Malfunction Cause Determination and Corrective Actions

a. Inspection Scope

The inspectors reviewed selected documents, schematics, operator logs, and chart recordings and conducted interviews to determine the sequence of events associated with the T21A11 breaker trip and re-closure. This information was used to evaluate the licensee's cause determination and corrective actions.

b. Findings and Observations

Introduction

No findings of significance were identified.

Discussion

Approximately 1 hour and 10 minutes after the reactor trip, the Unit 2 AB EDG output breaker to bus T21A (T21A11) cycled open and re-closed 23 seconds later. When the breaker opened, a load sequence signal on the T21A bus was initiated so that loads sequenced onto the bus when the breaker re-closed. Before this, all indications were normal for bus T21A and breaker T21A11. The breaker re-closure was a result of the existing state of the plant and not an automatic feature. When the permissive conditions were again met, the master relay sent a close signal to the T21A11 breaker and the loads were re-sequenced onto the bus. The T21A11 breaker remained closed after the second closure for the remainder of the event (about 6 hours). At 11:55 a.m., the bus configuration was altered to supply power to bus T21A from offsite power via bus 2A.

During the investigation process, breaker T21A11 was removed from service, and replaced with a spare, to allow the breaker to be tested using current plant preventive maintenance procedures. No abnormal conditions were observed during the breaker testing.

The licensee's investigation concluded that the opening and subsequent re-closing of breaker T21A11 was caused by abnormal behavior of Agastat relay 62-2X-DGAB (AB EDG Trip Control Auxiliary Time Delay Relay). The failure of this relay to remain closed would have caused the T21A11 breaker to open. If the Agastat relay then closed (an expected state at time of event), a close signal to T21A11 would be generated. The 62-2X-DGAB relay was removed from service and tested. The relay's coil was found to be defective and a new relay was installed.

The replaced 62-2X-DGAB relay was functionally checked with all the required circuitry that was in question via a functional testing plan on November 10th and found to be in working order. The licensee was evaluating the extent of condition with respect to other Agastat relays installed in safety-related circuits and additional corrective actions for the extent of condition will be determined after forensic evaluation of the failed relay. The results of post mortem testing of the relay were not available at the conclusion of this inspection. The licensee replaced Agastat relays on both the Unit 2 AB and CD EDGs.

The inspectors thoroughly examined the licensee's preliminary apparent cause evaluation and concluded that the licensee had not neglected any likely factors. The inspectors concluded that the evaluation was sufficiently thorough and that corresponding immediate corrective actions appropriately addressed the cause. The licensee had not yet completed its final cause evaluation at the conclusion of this inspection and had not yet formulated other corrective actions. The final cause evaluation and corrective actions will be considered for inclusion in subsequent problem identification and resolution inspections.

.7 Evaluation of Any Plant Equipment Powered from the Safety-Related Buses that May Have Been Impacted by Degraded Voltage Conditions

a. Inspection Scope

The inspectors reviewed selected recordings of generator voltage, power, and reactive power to evaluate the duration of the degraded and/or undervoltage conditions on the safety-related buses before and during the event. The inspectors reviewed selected documents, schematics, and operator logs and conducted interviews to determine the potential impact on plant equipment as a result of degraded voltage conditions.

b. Findings and Observations

Introduction

No findings of significance were identified.

Discussion

The inspectors noted that there was a momentary disturbance about 90 minutes (less than 1 percent of output voltage) before the event which was too small to cause an alarm. Operators responded to alarms generated by the larger magnitude (about 10 percent of output voltage) rapid swings that occurred about 5 minutes before the larger voltage swing which tripped the reactor. The output voltage had returned to nominal (4160 Vac on the safety-related buses) within about 2 minutes before the large voltage change occurred. The inspectors verified the as-left settings on the under-voltage relays from calibration records. The degraded voltage alarm was set at a nominal 92 percent (~3827 volts), the safety-related T-buses undervoltage was set at 77.5 percent (3224 volts), and the RCP bus undervoltage reactor trip was set at 73 percent (3051 volts). Therefore, the order of reaching the under voltage setpoints were the degraded voltage alarm, then the load shed and diesel start, and then the reactor trip on RCP bus undervoltage. The final voltage transient was very rapid in developing, reaching all three set-points almost simultaneously. The results were that the T-21A bus was re-powered by the AB EDG, the T-21B bus was de-energized, and the T-21C and T-21D buses received power from the off-site power source with the rapid transfer to the reserve auxiliary transformer. Since the under-voltage transients experienced were of very short duration, the inspectors concluded that there would be no expected damage to plant equipment as a result of their operation under degraded voltage conditions.

4OA6 Meetings

Exit Meetings

The inspectors presented the inspection results to Mr. J. Jensen and other members of licensee management at the conclusion of the inspection on November 18, 2005. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On December 9, 2005, the team leader discussed changes to the characterization of the issues since the previous exit meeting with Mr. J. Jensen and Mr. M. Scarpello. The licensee acknowledged the information discussed.

ATTACHMENTS:
1. SUPPLEMENTAL INFORMATION
2. SPECIAL INSPECTION TEAM CHARTER

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Crane, Acting Regulatory Affairs Supervisor
D. Fadel, Engineering Vice President
R. Gillespie, Operations Director
J. Jensen, Site Vice President
C. Lane, Engineering Programs Manager
J. McClelland, System Engineer
M. Scarpello, Regulatory Affairs Supervisor
K. Steinmetz, Licensing Engineer
S. Vasquez, System Engineering Manager
L. Weber, Plant Manager
W. Wah, System Engineer

Nuclear Regulatory Commission

C. Lipa, Chief, Reactor Projects Branch 4
J. Lennartz, Resident Inspector

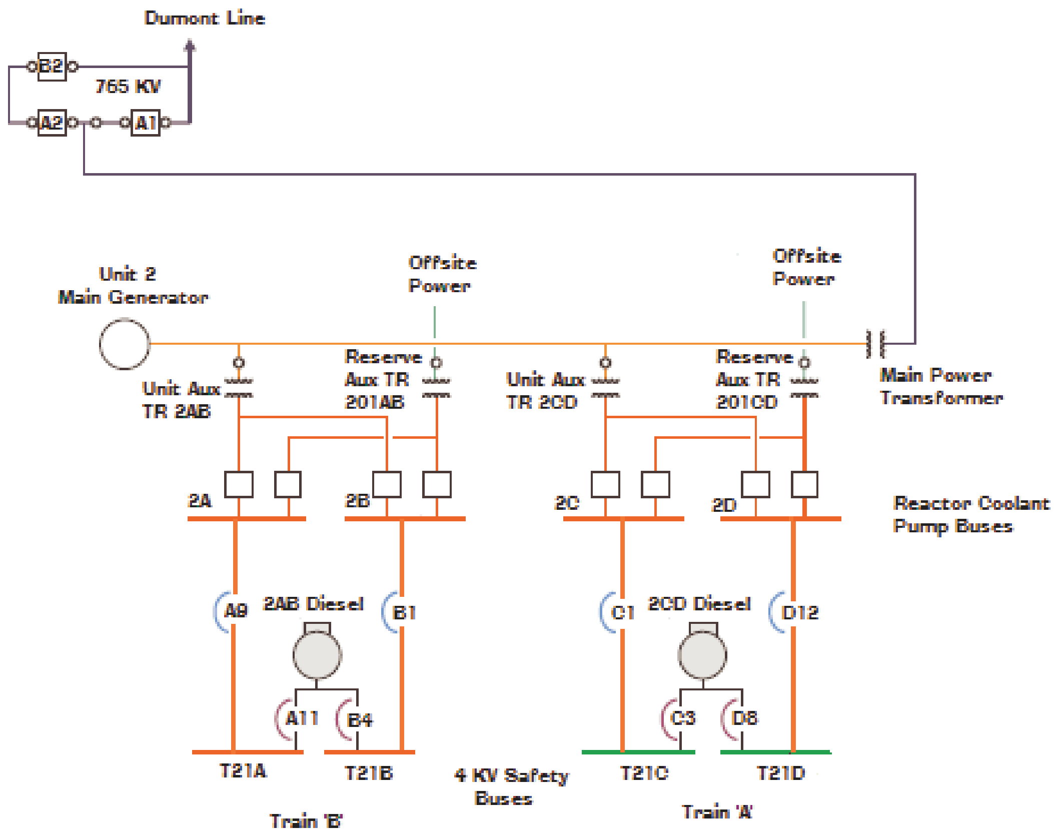
LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000316/2005013-01	FIN	Inadequate Preventive Maintenance on Main Generator Exciter Resulted in a Reactor Trip (Section 4OA3.3)
05000316/2005013-02	NCV	Failure to Perform Adequate Post Maintenance Testing, Resulting in a TS 3.8.1 Violation (Section 4OA3.5)

Figure 1

D. C. Cook Unit 2
Electrical Power Distribution



LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Corrective Action Program Documents

- CR 05322007, "NRC Observation Resulting from the Special Inspection Following the Unit 2 Reactor Coolant Pump Bus Undervoltage Reactor Trip on November 8, 2005," November 18, 2005
- CR 05322048, "Areas for Improvement in Communication with the Regulator Coming Out of the Response to the Reactor Trip on November 8, 2005 and the Special Inspection Exit Resulting from the Complications After the Reactor Trip," November 18, 2005
- CR 05312013, "Unit 2 Experienced an Automatic Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage," November 8, 2005
- CR 05312006, "2-T21B Did Not Close In When Unit Tripped," November 8, 2005
- CR 05312011, "Arcing Observed at 2-OME-81-EXC - Investigate and Repair 2-OME-81-EXC As Required," November 8, 2005
- CR 05325046, "The t21A11 Beaker Momentarily Opening and Then Re-closing on 11/8/05 Was Not Reported in a Timely Manner," November 21, 2005
- CR 05325035, "NRC Observation Resulting from the Special Inspection Following the Unit 2 Reactor Coolant Pump Bus Undervoltage Reactor Trip on November 8, 2005," November 21, 2005
- CR 5318032, "Agastat F9400 series timing relays are nearing end of life with no identified replacements," November 14, 2005
- CR 05319017, "While Performing Set Up of Spare Breaker, Step 4.12.9f (anti-pump operability test) of Procedure 12-IHP-5021-EMP-012, the Craft Omitted checking SAT/UNSAT Boxes for Test Results," November 15, 2005
- CR 05321016, "T21A11 Breaker Momentarily Opened and Then Re-Closed During U2 Trip," November 17, 2005
- Apparent Cause Evaluation for the Unit 2 Main Exciter Investigation, November 10, 2005
- Preliminary Apparent Cause Evaluation for the Unit 2 T21B4 Breaker Malfunction Investigation, November 10, 2005
- Preliminary Apparent Cause Evaluation for the Unit 2 T21A11 Breaker Malfunction Investigation, November 10, 2005

Calculations

- PRA_SDP_001, "Risk Assessment for Breaker 2-T21B4 Failure on 11-08-05," Revision 0

Drawings

- C OP-2-12001-39, "Main Auxiliary One-Line Diagram Bus "A" & "B" Engineered Safety System (Train "B")", Revision 39
- C OP-2-12010-21, "MCC Aux One-Line 600V Bus 21A, 21B, Engineered Safety System (Train "B"), Revision 21
- C OP-2-12013-18, "MCC Aux One-Line 600V Bus 21A, 21B, Engineered Safety System (Train "B")," Revision 18
- C OP-2-12015-16, "Distr Pnl Aux One-Line 600V Bus 21A, 21B, Engineered Safety System (Train "B")," Revision 16
- OP-2-98043-39, "4Kv. Diesel Generator 2AB A.C.B. Elementary Diagram," Revision 39
- OP-2-98034-36, "Diesel Generator 2AB Control Elementary Diagram," Revision 36
- OP-2-98655-14, "Operating. Sequence Monitor Sheet No. 1 Elementary Diagram," Revision 14
- C SOD-08201-001, "Engineered Safety Systems Electrical," Revision 2

Procedures

- C OHI-4000, "Conduct of Operations Standards," Revision 19
- C OHI-4016, "Conduct of Operations Guidelines," Revision 13
- C PMI-2294, "Post Maintenance Testing Program," Revision 3
- C PMI-7090, "Plant Quality Control Inspection Program," Revision 8a, Change 0
- C PMP-7090-001-001, "Identification of Inspections," Revision 1, Change 0
- C PMP-7090-001-002, "Plant Quality Control Inspection Program Implementation," Revision 2
- C 2-OHP-4024-221, "Annunciator #221 Response: Generator," Revision 13
- C 12-IHP-5021-EMP-012, "ITE 4KV Circuit Breaker Maintenance," Revision 10
- C 12-EHP-5015-BKR-001, "Metal-Clad Circuit Breaker Maintenance Program," Revision 4

Work Requests/Work Orders

- C Job Order 05312006, "T21B Output Breaker Failed to Close Post Load Shed, Check Wiring for 12-MOD-45617 (Non-Intrusive)," November 10, 2005
- C Job Order RT 00022164-01, "Main Generator/Exciter, U-2 Transformers and Spare Batteries Weekly PM Task," August 19, 2004
- C Job Order 12-MOD-45617, "Supplemental Emergency Diesel Work, Install Unit 2 Test Switch Train 'B'," October 1, 2005
- C Job Order 12-MOD-45617, "Supplemental Emergency Diesel Work, Testing Unit 2 Test Switch Train 'B'," October 27, 2005
- C Job Order 05088013-31, "12-MOD-45617, Unit 2, Installation of Load Conservation Switch "B"(2AB)," October 17, 2005
- Job Order R0280251, "Weekly PM Task: MN Generator / Exciter and U-1 XFMRS," November 9, 2005
- Job Order R00022164-01, "Main Generator/Exciter, U-2 Transformers and Spare Batteries Weekly PM Task," October 11, 2005

Other Documents

- D. C. Cook Nuclear Plant Unit 2 TSs and Bases
- D. C. Cook Nuclear Plant Updated Final Safety Analysis Report, Revision 20
- Event Notification Worksheet EN#42125, November 8, 2005
- Shift Manager's Logs, October 27, 2005 through November 11, 2005
- Unit 2 Reactor Trip Review Report, November 10, 2005
- Clearance Order N-EDG-DGAB-0846, "Testing of New Load Conservation Switch (12–MOD-45617)," November 10, 2005
- VTD-BROW-0839, "ASEA Brown Boveri Slipring Brushes Type ZK and ZZ XG180," Revision 0

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
CR	Condition Report
DRP	Division of Reactor Projects
EDG	Emergency Diesel Generator
FIN	Finding
IMC	Inspection Manual Chapter
LCO	Limiting Condition for Operation
MVARS	Mega-Volt Amperes Reactive
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OA	Other Activities
PDR	Public Document Room
RCP	Reactor Coolant Pump
SDP	Significance Determination Process
TS	Technical Specification

D.C. COOK SPECIAL INSPECTION CHARTER

This Special Inspection is chartered to assess the circumstances surrounding the November 8, 2005 reactor trip and subsequent breaker issues. The inspection should evaluate the causes of the automatic reactor trip, and the loading of the safety-related buses and the operation of associated safety-related breakers following the event. The Special Inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection," and will include, but not be limited to, the following items:

1. Establish a sequence of events for the November 8, 2005, event, including a detailed voltage response. (Event Number 42125)

2. As necessary, interview plant personnel that were involved in the event to aide in the determination of the technical aspects surrounding the reactor trip and plant response.

3. Evaluate the licensee's cause determination and corrective actions for the main generator failure, that initiated the event.

4. Review the loading of the safety-related buses and the operation of associated safety-related breakers following the event.

5. Assess the licensee's cause determination and corrective action of the T21B emergency bus not becoming energized.

6. Evaluate the licensee's cause determination and corrective actions of the T21A11 breaker trip and re-closure approximately 1 hour and 10 minutes into the event.

7. Evaluate any equipment powered from the safety related buses that may have been impacted by degraded voltage conditions.

8. Assess the adequacy prior to restart, of the licensee's overall corrective action to this event.