June 21, 2004

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER PLANT, UNIT 3
NRC SPECIAL INSPECTION REPORT 05000249/2004009

Dear Mr. Crane:

On May 14, 2004, the U.S. Nuclear Regulatory Commission completed a Special Inspection at your Dresden Nuclear Power Plant to evaluate the facts and circumstances surrounding the Unit 3 Loss of Offsite Power event which occurred on May 5, 2004. The enclosed report documents the inspection findings which were discussed on May 14, 2004, with Mr. D. Bost and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to 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 May 5, 2004, at about 13:27 (CDT), Unit 3 at the Dresden Nuclear Power Plant was operating at full power when an automatic reactor scram and subsequent Loss of Offsite Power event occurred during activities to reconfigure breakers in your plant switchyard. All control rods fully inserted and the emergency diesel generators started and successfully supplied power to the onsite vital buses, as designed. Your staff declared an Unusual Event at 13:52 (CDT) on May 5, 2004, as required by your Emergency Plan. At approximately 16:00 (CDT), on May 5, 2004, offsite power was restored to one Unit 3 safety bus and the Unusual Event was terminated.

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 equipment performance problems which occurred during the event, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection." The purpose of the inspection was to evaluate the facts and circumstances surrounding the event, as well as the actions taken by your staff in response to this event. The inspection focus areas are detailed in the Special Inspection Charter (Attachment 2).

Based on the results of this special inspection, three self-revealed findings of very low safety significance (Green) were identified. Two of the findings were determined to involve violations of NRC requirements. The first finding, not associated with a violation of NRC requirements, was related to inadequate preventive and corrective maintenance performed on Switchyard Breaker 8-15 which caused the 'C' Phase of Breaker 8-15 to not open when operated on

May 5, 2004. The failure of the ‘C’ phase of Breaker 8-15 to open when the ‘A’ and ‘B’ phases opened produced current imbalances in both the Unit 2 and Unit 3 switchyards which directly led to the automatic scram of Unit 3 due to a turbine load reject and a Unit 3 Loss of Offsite Power. The second finding, associated with a violation of NRC requirements, dealt with inadequate procedures for the restoration of offsite power to the safety-related busses, which would have resulted in the unnecessary opening of the emergency diesel generator output breaker supplying power to the bus. The third finding, associated with a violation of NRC requirements, dealt with an inoperable secondary containment when the opposite unit’s drywell purge fans were in operation. Because of the very low safety significance and because you have entered these issues into your corrective action program, the NRC is treating these two findings as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC’s Enforcement Policy.

Immediate remedial corrective actions were taken to prevent recurrence. Those actions included repairs of Switchyard Breaker 8-15, procedure changes to address restoration of offsite power to the safety-related busses, and procedure changes to secure the opposite unit’s drywell purge fans upon actuation of the standby gas treatment system. At the conclusion of the inspection, your staff continued working to complete the root cause evaluations for the issues identified during this event and indicated several other long term actions would be implemented upon completion of the root cause evaluations.

If you contest the findings, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 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, DC 20555-0001; and the NRC Resident Inspector Office at the Dresden 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 by Patrick L. Hiland Acting for/

Steven A. Reynolds, Acting Director
Division of Reactor Projects

Docket Nos. 50-249
License Nos. DPR-25

Enclosure: Inspection Report 05000249/2004009
w/Attachments:
1. Supplemental Information
2. Special Inspection Charter
3. Offsite Switchyard Diagram

See Attached Distribution

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Regulatory Assurance Manager - Dresden
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No:	50-249
License No:	DPR-25
Report No:	05000249/2004009
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Unit 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	May 6 through 14, 2004
Inspectors:	R. Krsek, Senior Resident Inspector, Kewaunee R. Daley, Senior Reactor Inspector, Region III P. Pelke, Reactor Engineer, Region III R. Ruiz, Reactor Engineer, Region III
Senior Reactor Analyst:	M. Parker, Senior Reactor Analyst, Region III
Approved By:	M. Ring, Chief Reactor Projects Branch 1

Enclosure

SUMMARY OF FINDINGS

IR 05000249/2004009; 05/06/2004 - 05/14/2004; Exelon Generation Company, Dresden Nuclear Power Station, Unit 3; Special Inspection to review circumstances surrounding the Unit 3 automatic scram and Loss of Offsite Power event.

This report covers a 2-week period of special inspection by NRC resident and region-based inspectors. The inspection identified three Green findings, two of which were associated Non-Cited Violations. 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A self-revealed finding was identified for the failure to perform the appropriate preventive and corrective maintenance on Switchyard Breaker 8-15 which resulted in the failure of Breaker 8-15 to open fully when manipulated by operations personnel on May 5, 2004. The failure of the 'C' Phase of Breaker 8-15 to fully open when the 'A' and 'B' phases opened caused significant current imbalances in the Unit 2 and Unit 3 switchyards. These imbalances caused the automatic reactor scram of Unit 3 from full power and the subsequent loss of offsite power to both Unit 3 Emergency Core Cooling System Busses. The finding was not considered a violation of regulatory requirements.

  The inspection team determined that this finding was more than minor because the finding was associated with an increase in the likelihood of an initiating event, Loss of Offsite Power. The initial Phase 1 and Phase 2 SDP risk assessment characterized this finding as potentially risk significant using the benchmarked site specific Risk-Informed Inspection Notebook. However, a Phase 3 analysis performed by the Senior Reactor Analyst determined the issue was of very low safety significance, after evaluating the actual increase in initiating event frequency. The Senior Reactor Analyst concluded the safety significance of the inspection finding based on the change in core damage frequency and large early release frequency was of very low safety significance (Green). As a remedial corrective action, the licensee and Exelon Energy Delivery personnel performed the appropriate corrective maintenance on Breaker 8-15 to preclude repetition. The licensee and Exelon Energy Delivery personnel continued to evaluate the root and contributing causes of the event, as well as long-term corrective actions, at the end of the inspection period. (Section 4OA3.2)

Cornerstone: Mitigating Systems

- Green. A self-revealed finding was identified for the failure to incorporate appropriate procedure steps to prevent the inadvertent automatic closure of the alternate feeder breaker to Bus 33, during the restoration of offsite power. This finding was a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V.

The inspection team determined that this finding was more than minor because the mitigating systems cornerstone objective was affected. Specifically, inadvertent tripping of an Emergency Diesel Generator output breaker could affect the potential availability of an Emergency Diesel Generator for mitigating the effects of a Loss of Offsite Power. The inspection team concluded that this finding was of very low safety significance (Green), since the reverse power trip of the Emergency Diesel Generator output breaker did not adversely affect the functional capability of the 2/3 Emergency Diesel Generator during the actual Loss of Offsite Power event. As an immediate corrective action, the licensee revised the offsite power restoration procedure to correct the deficiency. (Section 4OA3.4)

Cornerstone: Barrier Integrity

- Green. A self-revealed finding was identified involving an inadequate secondary containment leak rate test procedure which resulted in a Non-Cited Violation of Technical Specification 3.6.4.1 for an inoperable secondary containment when the drywell purge fans were operating. For example, secondary containment was inoperable on May 5, 2004, while Unit 3 was in Mode 1 and the Unit 2 drywell purge fans were operating.

  The finding was more than minor because if left uncorrected it would become a more significant safety concern, and was associated with the Barrier Integrity cornerstone objective to provide reasonable assurance that containment protects the public from radionuclide releases caused by accidents or events. The finding was determined to be of very low safety significance (Green) because the finding only represented a degradation of the radiological barrier function of secondary containment. As an immediate corrective action, licensee personnel revised the applicable alarm response procedures to secure the running drywell purge fans on either unit, if reactor building ventilation trips and isolates. In addition, a work request was initiated to repair the in-leakage to the drywell purge filter housings discovered by the licensee. (Section 4OA3.5)

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

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Event

On May 5, 2004, Dresden Unit 3 was at full power and Dresden Unit 2 was shutdown. Offsite power Line 1223 in the Unit 3 switchyard ring bus was out of service for scheduled maintenance. Operations personnel were implementing a switching order which cross-tied the Unit 2 and Unit 3 switchyard ring busses to provide an alternative source of power to the Unit 3 Reserve Auxiliary Transformer. Operations personnel manually opened Switchyard Breaker 8-15 in accordance with the switching order. However, when the ‘A’ and ‘B’ phases of Breaker 8-15 opened, the ‘C’ phase of Breaker 8-15 failed to fully open within the required time frame. This failure caused current imbalances in both the Unit 2 and Unit 3 switchyard ring busses. The current imbalances in the switchyard first resulted in a Unit 3 automatic scram due to a turbine load reject. The continued current imbalances then caused a loss of power to the Unit 3 Reserve Auxiliary Transformer which resulted in a Unit 3 Loss of Offsite Power (LOOP) to the safety-related Emergency Core Cooling System (ECCS) Busses.

The licensee declared an Unusual Event in accordance with the Emergency Plan and exited the Unusual Event approximately two and a half hours later following the restoration of offsite power to one onsite safety-related electrical bus. During the event the licensee also experienced several other anomalies which included the following: the inadvertent opening of a diesel generator output breaker upon restoration of offsite power to the first safety-related electrical bus; the inability of the standby gas treatment system to maintain the proper differential pressure in secondary containment; and the inability to initially close a bus cross tie breaker needed for the restoration of the condensate system.

Inspection Scope

Based on the probabilistic 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 which occurred, a Special Inspection was initiated in accordance with Inspection Procedure 93812, "Special Inspection."

The inspection focus areas included the following charter items:

- Establish a sequence of events, including event notification and classification;
- Monitor and assess the licensee’s determination of the root cause of the LOOP event, human performance, equipment performance, and adequacy of procedures;
- Review the licensee’s performance with emergency preparedness procedures and communication to the NRC. In particular, review communications surrounding the trip of the 2/3 Emergency Diesel Generator and the licensee’s decision-making surrounding the exit from the Unusual Event;
- Monitor and assess the licensee’s determination of the root cause of the circumstances surrounding the trip of the 2/3 Emergency Diesel Generator including actions for restoration of the Emergency Diesel Generator;
- Monitor and assess the licensee’s efforts to evaluate the inability of the standby gas treatment system to maintain the proper differential pressure in secondary containment;

- Monitor and assess the licensee's determination of the root cause and the circumstances surrounding the inability to restore power to Bus 36 and to restore a condensate pump; and
- Evaluate the licensee's efforts to determine the extent of condition for root causes identified above.

4. OTHER ACTIVITIES (OA)

4OA3 Special Inspection (93812)

.1 Establish a Sequence of Events Including Event Notification and Classification

a. Inspection Scope

The inspection team reviewed control room logs, plant process computer alarm logs, and an event chronology developed by licensee personnel. The inspection team also interviewed several licensee personnel and Exelon Energy Delivery personnel to validate and further establish the sequence of events which occurred on May 5, 2004. The licensee for Dresden is Exelon Nuclear. The transmission and distribution company is Exelon Energy Delivery (EED).

Based on these reviews and interviews, the inspection team developed a sequence of events for the May 5, 2004, Unusual Event emergency condition as a result of the Dresden Unit 3 Loss of Offsite Power (LOOP). The inspection team verified that the appropriate Technical Specifications were entered and exited for the events which occurred on May 5, 2004.

b. Findings and Observations

Introduction: No findings of significance were identified.

Attachment 3 of this inspection report provides a diagram of the Unit 2 and Unit 3 switchyard ring busses which will assist in understanding the sequence of events which occurred in the Unit 2 and Unit 3 switchyards on May 5, 2004.

Discussion: The Unit 2 and Unit 3, 345 kiloVolts (kV) switchyard ring busses, as shown in Attachment 3 of this inspection report, were normally separated with Breaker 4-8 open. The Unit 2 switchyard ring bus has four offsite lines capable of supplying offsite power to the switchyard ring bus, Lines 2311, 1220, 1221, and 0302. The Unit 3 switchyard ring bus has three offsite lines capable of supplying offsite power to the switchyard, Lines 1222, 1223 and 8014.

The inspection team learned through interviews with EED personnel that two types of protective relays actuated in the switchyard during the May 5, 2004, event. The first protective relay was the nondirectional time overcurrent type, which actuated when current imbalances existed within the switchyard. When actuated, the nondirectional time overcurrent protective relays isolated individual offsite power lines in the switchyard, through the opening of switchyard breakers. The other type of protective relay which actuated during the event was referred to as the Local Breaker Backup (LBB) relay. The LBB relay only actuated when a switchyard breaker received a switchyard protective relay signal to open (e.g. nondirectional time overcurrent) and the breaker did not open within the required time frame (approximately 6.5 cycles). When actuated, the LBB relay isolated the breaker which did not open by opening all the breakers adjacent to the breaker which failed to open.

The inspection team also determined that the switchyard breakers were owned and maintained by the transmission and distribution company, EED. Licensee personnel performed daily equipment monitoring activities in the switchyard, and manipulated the switchyard breakers from the control room utilizing switching orders provided by EED and approved by site operations personnel.

The inspection team determined the following plant conditions of significance existed prior to the event:

- On May 1, 2004, EED requested and removed Line 1223 from service to perform maintenance;

- On May 3, 2004, EED contacted the licensee control room operators to perform testing of Line 1223 following maintenance. Operations personnel assessed the potential risk of performing Line 1223 testing in conjunction with the Unit 3 isolation condenser out of service and concluded the testing should not be conducted due to the potential orange risk condition. Based on this assessment by licensee personnel, testing was deferred to May 5, 2004.

The inspection team determined the following sequence of events occurred on May 5, 2004:

Time	**Event Description**
12:00 p.m.	Unit 2 was shutdown and Unit 3 was operating at full power. Online risk was determined to be yellow due to planned testing and switchyard work for Line 1223.
12:29:40	Unit 3, 345 kV Switchyard Breakers 8-9 and 9-10 were opened by licensee operations personnel in accordance with the switching order to isolate Line 1223 in support of testing.
13:26:16	Unit 2 / Unit 3, 345 kV Switchyard Crosstie Breaker 4-8 was closed by licensee operations personnel in accordance with the switching order to provide an alternative source of power to the Unit 3 Reserve Auxiliary Transformer (RAT) TR-32.
13:27:31	Unit 3, 345 kV Switchyard Breaker 8-15 was manually opened by licensee operations personnel in accordance with the switching order. The ‘A’ and ‘B’ Phases of Breaker 8-15 successfully opened; however the ‘C’ phase failed to open. Because Breaker 4-8 was closed, the failure of Breaker 8-15 ‘C’ Phase to open caused significant current imbalances in both the Unit 2 and Unit 3 switchyard ring busses.

13:27:36	Due to the switchyard current imbalances, the Line 2311 nondirectional time overcurrent protective relays actuated which caused the following Unit 2, 345 kV Switchyard Breakers to open, as designed, Breakers 5-6, 6-7, and 1-7.
13:27:40	Due to the switchyard current imbalances, the breakers associated with Transformer 81 in the Unit 2 switchyard opened due to nondirectional time overcurrent protective relay actuations. Due to the continued switchyard current imbalances, the Line 1222 nondirectional time overcurrent protective relays actuated which caused the following Unit 3, 345 kV Switchyard Breakers to open, as designed, Breakers 10-11 and 11-14.
13:27:40	Dresden Unit 3 scrammed due to a turbine load reject when Breakers 10-11 and 11-14 opened, as designed. Unit 3 generated power was output to the grid through Line 1222 only; therefore the loss of Line 1222 resulted in the turbine load reject. Group I, II, and III isolations also occurred as a result of the scram.
13:27:48	Unit 2, 345 kV Switchyard Breaker 6-7 automatically closed on Line 2311, as designed. Line 2311 was still de-energized.
13:27:50	Line 1222 automatically re-closed at the remote terminal and re-energized Switchyard Bus 11. 345 kV Switchyard Breakers 11-14 and 10-11 remained open.
13:27:54	Due to the continued switchyard current imbalances, the Line 8014 nondirectional time overcurrent protective relays actuated which caused the following Unit 3, 345 kV Switchyard Breakers to receive an open signal, as designed, Breakers 11-14 (already open) and 8-15. Upon receipt of a second open signal Breaker 8-15 'C' Phase continued to remain open. Breaker 8-15 'C' Phase failed to open a second time and the local breaker backup protection relay was actuated for Breaker 8-15. Consequently an open signal was sent to Unit 3, 345 kV Switchyard Breaker 8-9 (already open) and Unit 2 / Unit 3, 345 kV Switchyard Crosstie Breaker 4-8.
13:27:54	Unit 2 / Unit 3, 345 kV Switchyard Crosstie Breaker 4-8 opened which resulted in the loss of power to Reserve Auxiliary Transformer TR-32. This in turn resulted in the LOOP to the Unit 3 ECCS and onsite Alternating Current (AC) Busses. Emergency Diesel Generator (EDG) U-3 automatically started and energized safety-related Bus 34-1, as designed.

Emergency Diesel Generator 2/3 started and energized safety-related Bus 33-1, as designed.

Standby Gas Treatment system started with Group II isolation signal, but secondary containment differential pressure cannot be maintained greater than 0.25 inches of water. Reactor Operators entered the appropriate Technical Specification.

Spent fuel pool cooling was lost due to the LOOP event. Reactor Operators entered the appropriate abnormal procedure for loss of spent fuel pool cooling.

13:29 High pressure coolant injection (HPCI) manually initiated by reactor operators for reactor water level control.

Isolation Condenser manually initiated by reactor operators for reactor pressure control.

Low Pressure Coolant Injection and Containment Cooling Service Water manually initiated by reactor operators for torus cooling.

13:40 Unit 3 Station Blackout Diesel started by reactor operators and Bus 34 was energized.

13:42 Shift Emergency Director declared a Notice of Unusual Event (Emergency Action Level MU1, “Unplanned Loss of All Offsite AC Power to a Unit’s ECCS Busses”) due to the LOOP.

13:52 Licensee personnel completed Nuclear Accident Reporting System (NARS) notification of the declaration of a Notice of Unusual Event to the State of Illinois. (Initial contact was made at 13:49.)

14:03 Licensee personnel energized Bus 35 from Bus 33 and energized Bus 37 from Bus 34.

Licensee personnel attempted to re-energize onsite Bus 36 from Bus 34, and the 4kV cross-tie breaker tripped open.

14:12 Licensee personnel completed the emergency notification system call to the NRC Headquarters Duty Officer. Emergency Notification System called for the Unit 3 scram and subsequent LOOP, Event Notification No. 40727.

14:28 Licensee personnel restarted the Unit 2 and Unit 3 spent fuel pool cooling pumps, which restored spent fuel cooling which was lost due to the LOOP. Reactor Operators exited the abnormal procedure for loss of spent fuel pool cooling.

15:25 Reactor Operators secured the Unit 2, 2A and 2B Drywell purge fans to improve secondary containment differential pressure. This action allowed the Standby Gas Treatment system to maintain a secondary containment differential pressure of greater than 0.25 inches of water, as required.

15:38	Switchyard Breaker 4-8 was manually closed by operators which energized Reserve Auxiliary Transformer TR-32 with offsite power.
15:54	Reactor Operators reset the Unit 3 Generator relays.
15:58	Reserve Auxiliary Transformer (RAT) TR-32 automatically energized the 4kV Busses 33-1 and 33 unexpectedly. Emergency Diesel Generator 2/3 output breaker tripped open on reverse power. Bus 33-1 and 33 remained energized via offsite power through RAT TR-32.
16:01	Unusual Event Terminated by Emergency Director when one division of safety-related equipment was energized by offsite power (i.e., Bus 33-1).
16:02	With Bus 33 and 33-1 energized by offsite power, EDG 2/3 secured and placed in standby.
16:11	Licensee personnel completed NARS notification of the termination of a Notice of Unusual Event to the State of Illinois.
16:30	Since secondary containment differential pressure remained greater than 0.25 inches of water since 15:25, Reactor Operators exited the Technical Specification Limiting Condition of Operation.
16:46	Licensee personnel completed the Event Notification System notification made to the NRC Headquarters Duty Officer for termination of Unusual Event.
17:29	Reserve Auxiliary Transformer TR-32 was paralleled with the Unit 3 Station Blackout Diesel.
17:31	Unit 3 Station Blackout Diesel Generator was secured from Bus 34 and placed in standby. Bus 34 was energized via offsite power.
18:59	Licensee personnel reconnected Bus 34 to Bus 34-1 and separated Bus 34-1 from EDG U-3. Therefore, the remaining division of safety related equipment was energized by offsite power.
19:02	Emergency Diesel Generator U-3 was secured and placed in standby
19:44	Reserve Auxiliary Transformer TR-32 was identified as having no cooling because Bus 36 remained de-energized (reference 14:03 entry).
21:03	Licensee electrical maintenance and operations personnel attempted to re-energize Bus 36 through Bus 34 cross-tie breaker. Bus 34 Cross-tie breaker automatically opened a second time.
21:17	Licensee personnel replaced the Bus 34 cross-tie breaker with a qualified spare. Upon replacement the Bus 34 cross-tie breaker was closed and

energized Bus 36. Therefore, all internal plant loads had offsite power restored.

21:37 Licensee personnel noted that all RAT TR-32 auxiliary systems, including cooling, were restored and normal.

.2 Monitor and Assess the Licensee's Determination of the Root Cause of the Loss of Offsite Power Event, Human Performance, Equipment Performance, and Adequacy of Procedures

a. Inspection Scope

The inspection team reviewed applicable documents related to the following activities: the planning and scheduling of the switchyard work which took place on May 5, 2004; the switchyard configuration risk and reliability study results performed by EED and reviewed by licensee operations personnel; EED maintenance and work order history for select switchyard breakers; switchyard breaker vendor manuals; and prompt investigation reports generated by the licensee as a result of this event. In addition, the inspection team interviewed licensee operations, engineering and maintenance personnel and EED operations, scheduling, maintenance, and transmission and distribution personnel. The inspection team also performed walkdowns of plant equipment including the switchyard, onsite electrical distribution systems and the control room.

b.1 Description of Event

On May 5, 2004, Dresden Unit 3 was at full power and Dresden Unit 2 was shutdown. Offsite power Line 1223 in the Unit 3 switchyard ring bus was out of service for scheduled maintenance and subsequent post maintenance testing. Control room operations personnel implemented an EED switching order which cross-tied the Unit 2 and Unit 3 switchyard ring busses through Switchyard Breaker 4-8 to provide an alternative source of power to the Unit 3 Reserve Auxiliary Transformer TR-32. In April 2004, Exelon Energy Delivery had communicated to licensee operations personnel two switchyard configurations to support the post maintenance testing of Line 1223, following scheduled maintenance on Line 1223. Therefore, the switching order implemented by the control room operators on May 5, 2004, was reviewed and selected by licensee operations personnel.

At approximately 13:26 on May 5, 2004, operations personnel closed Switchyard Breaker 4-8 in accordance with the switching order, which cross-tied the Unit 2 and Unit 3 switchyard ring busses. At 13:27 operations personnel manually opened Switchyard Breaker 8-15, in accordance with the switching order. The 'A' and 'B' phases opened, however, the 'C' Phase of Breaker 8-15 failed to fully open within the required time frame which caused current imbalances in both the Unit 2 and Unit 3 switchyard ring busses. The current imbalances in the switchyard resulted in the following events, as described in detail in Section 4OA3.1 of this report:

- Unit 3 automatic scram due to a turbine load reject when Line 1222 was de-energized in the Unit 3 switchyard due to the switchyard current imbalances; and
- Loss of Offsite Power to the Unit 3 ECCS Busses due to the Local Breaker Backup relay protection actuation for Breaker 8-15.

The onsite emergency diesel generators automatically started and energized the safety-related busses, as designed. The licensee also had the capability during the event of supplying offsite power to certain safety-related busses in Unit 3 through a manual crosstie to the Unit 2 Reserve Auxiliary Transformer TR-22; however, the licensee elected not to utilize this option because the emergency diesel generators had performed the intended function of energizing the safety-related busses without incident. The licensee declared an Unusual Event in accordance with the Emergency Plan and exited the Unusual Event approximately two and a half hours later following the restoration of offsite power to one onsite safety-related electrical bus (See Section 4OA.3 of this report).

During the event the licensee also experienced several other anomalies which included the following: the inadvertent opening of a diesel generator output breaker upon restoration of offsite power to the first safety-related bus (See Section 4OA.4 of this report); the inability of the standby gas treatment system to maintain the proper differential pressure in secondary containment (See Section 4OA.5 of this report); and the inability to initially close a bus cross tie breaker needed for the restoration of the condensate system (See Section 4OA.6 of this report).

Immediately following the event, the licensee established and the inspection team monitored prompt investigation teams which investigated the facts surrounding the event and anomalies which occurred. The purpose of the licensee's prompt investigation teams was to initially establish what had occurred, to review potential immediate extent of condition issues and to identify remedial corrective actions to be taken to address the issues identified. At the end of the inspection, the licensee continued to perform root cause analyses on the events and anomalies which had occurred on May 5, 2004, to identify the root and contributing causes and to determine long term corrective actions to prevent recurrence.

b.2 Switchyard Breaker 8-15 Preventive and Corrective Maintenance History

Introduction: A Green self-revealed finding was identified for the failure to perform the appropriate preventive and corrective maintenance on Switchyard Breaker 8-15 which resulted in the failure of Breaker 8-15 to open when manipulated by operations personnel on May 5, 2004. The finding was not considered a violation of regulatory requirements.

Discussion: Following the May 5, 2004, event, licensee engineering and EED personnel evaluated the available switchyard electrical traces and determined that the Unit 2 and 3 switchyard current imbalances were caused by the failure of the 'C' Phase of Switchyard Breaker 8-15 to open. This was further verified by the licensee through a pole disagreement alarm for the 'C' Phase of Breaker 8-15 at the breaker local alarm panel.

Breaker 8-15 was an I-T-E Imperial Corporation (current 2004 vendor was Asea, Brown and Boveri (ABB)) Sulfur Hexafluoride (SF_6) gas circuit breaker Model C Type 362GA 63-20/30 Transmission Class. This breaker utilized independent pole operators for each of the three power line phases, 'A', 'B' and 'C'. Breaker 8-15 was built and installed in the Dresden Unit 3, 345kV switchyard in the late 1970's time frame.

The inspection team determined that when a breaker of this type received either a manual or automatic signal to open, two independent trip coils actuated within the internal mechanism of the breaker. The two trip coils, in turn, actuated two trip coil plungers which physically contacted a trip coil latch mechanism. The trip coil latch mechanism rested on a sealed bearing which had to roll freely in order for the trip latch mechanism to physically move. When operating properly, the physical movement of the trip latch mechanism within the breaker actuated other components which resulted in the opening of the breaker. This type breaker utilized independent pole operators for each of the three offsite power line phases. In the case of Breaker 8-15 on May 5, 2004, the 'A' and 'B' Phases opened properly; however, the 'C' Phase did not.

After the May 5 event, licensee and EED personnel quarantined Breaker 8-15 for investigation into the failure. As-found travel timing tests identified that the 'C' Phase was delayed in opening, with a time to open of 62 milliseconds. Repeated testing of Breaker 8-15 recreated and repeated the failure of Breaker 8-15 to open within the required acceptance criteria of 25 milliseconds.

On May 6, 2004, licensee and EED personnel discovered that ABB, the current breaker vendor, had issued a product advisory in July 2003 for I-T-E Imperial Corporation GA and GB Circuit Breakers which stated, in part, that the operating mechanisms may experience delayed trip or in some rare cases failures to trip due to age and application related problems. In addition, the advisory noted that the breakers at highest risk were those operated at less than twice per year. The product advisory recommended that the operating mechanisms in high-risk applications should be rebuilt utilizing new trip latch mechanism kits at the earliest convenience to ensure proper functioning of the breakers.

Upon disassembly of the trip latch mechanism, EED and licensee personnel identified the sealed bearing the trip latch mechanism rolled on, did not roll freely, but rather exhibited rough, grainy operation. The failure of the sealed bearing to roll freely directly contributed to the failure of the 'C' Phase of Breaker 8-15 to open within the required time frame. At the end of the inspection, EED personnel had sent the failed bearing to a vendor for further analysis.

As a remedial corrective action, EED personnel tested all three phases of Breaker 8-15 and identified that the operating mechanisms of the 'B' and 'C' Phases of Breaker 8-15 required immediate maintenance and were repaired. As-left testing of the 'C' Phase determined the time to open of the breaker was 20 milliseconds. As part of an extent of condition, the licensee also identified that Switchyard Breaker 6-7 was the same type breaker as Breaker 8-15. Preventive maintenance activities were performed on Breaker 6-7 in the Fall of 2003 with satisfactory as-found results for the breaker. In addition, Breaker 6-7 was cycled more than two times per year for the past several years based on switchyard history. Therefore, the licensee and EED personnel concluded that Breaker 6-7 was reliable and elected to install the vendor recommended operating mechanism kit at the next available opportunity. Based on the reviews of Breaker 6-7 maintenance and operating history, the inspection team did not identify any concerns with this corrective action.

The inspection team performed detailed reviews of the vendor manual, and maintenance and operating history for Breaker 8-15. In addition, the inspection team interviewed EED and licensee personnel associated with the monitoring, maintenance, and engineering for these switchyard breakers. The inspection team determined that preventive maintenance on Breaker 8-15 was last performed on March 27, 2002, which included routine inspection, lubrication and maintenance, a contact resistance test, and a travel timing test. The inspection team noted that the breaker failed the timing test on the ‘C’ Phase. Based on a review of the maintenance history, the inspection team determined that the trip latch mechanism pivot points were lubricated and the breaker was cycled successfully approximately 7 times, immediately thereafter. Following that activity, Breaker 8-15 was cycled in October 2002 and had remained in the closed position until May 5, 2004.

The inspection team reviewed the EED preventive maintenance activities as compared to the vendor product manuals. The inspection team noted that upon a failed timing test the EED procedure indicated to lubricate the breaker as required. However, in the Maintenance Section of the vendor manual, under periodic inspections, the vendor manual prescribed, in part, that when the operating mechanism showed signs of difficult or sluggish operation, the operating mechanism was to be disassembled to clean and lubricate as described in the manual. In addition, under the periodic cleaning and lubrication section, the manual stated, in part, that under ordinary circumstances the life of the grease in sealed bearings should be at least ten years and that if oxidation of the lubricant made the bearing sluggish, the bearing must be replaced. The inspection team noted that the EED preventive maintenance program and procedures for breakers did not include routine replacement of breaker parts which were expected to wear. In addition, the inspection team determined that the EED maintenance procedures did not give appropriate guidance to maintenance personnel to disassemble operating mechanisms which demonstrated sluggish or difficult operation to check for degraded bearings, nor did the procedure specify the appropriate lubricants to utilize on the various portions of the breaker.

During their investigation, the licensee and EED personnel also identified additional discrepancies between EED maintenance practices and vendor recommendations, without adequate technical justification for the deviations from the vendor recommendations.

The inspection team noted that prior to this event, EED personnel had begun implementation of a program to ensure appropriate preventive and corrective maintenance was performed on transmission and distribution equipment. As a result of the events at Dresden Unit 3 on May 5, 2004, EED personnel in conjunction with licensee personnel continued with the root cause investigation into the failure of Breaker 8-15. In addition, EED personnel accelerated reviews of vendor recommended practices and current operating practices for transmission and distribution equipment to ensure deviations from vendor recommendations had adequate technical justification. Exelon Energy Delivery personnel also contacted the vendors of the transmission and distribution equipment to assure that all the appropriate product advisories were available to EED personnel. Finally, EED and licensee personnel began reviews of other switchyard breakers to ensure that the appropriate corrective maintenance was performed for deficiencies identified during the recent preventive maintenance activities on switchyard breakers.

Analysis: The inspection team determined that the self-revealed failure to perform the appropriate preventive and corrective maintenance activities on switchyard breakers was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on June 20, 2003. The inspection team concluded that the failure to perform appropriate preventive and maintenance activities for switchyard breakers supplying offsite power as recommended by the vendor without appropriate technical justification, affected the initiating events cornerstone of reactor safety. In particular, the inspection team determined that the equipment performance and protection against external factors attributes were affected, as well as 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. Consequently, the inspection team concluded this finding was associated with an increase in the likelihood of an initiating event, Loss of Offsite Power, and was more than a minor concern.

The inspection team performed a Phase 1 Significance Determination Process (SDP) screening and determined that the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; therefore a Phase 2 was required and assistance from a Senior Reactor Analyst (SRA) was requested.

The SRA with the assistance of the inspection team evaluated the potential impact to both initiating event frequency and mitigating plant equipment including both safety-related and non safety-related equipment. No impact to mitigating plant equipment was identified, in part, because, offsite power was available through a manual cross-tie to certain equipment in Unit 3 through the Unit 2 Reserve Auxiliary Transformer; however, the finding was found to increase the LOOP initiating event frequency. In accordance with MC 0609, Appendix A, Significance Determination of Reactor Inspection Findings for At-Power Situations, the inspection team increased the initiating event frequency for the LOOP SDP worksheet an order of magnitude to account for the increase in loss of offsite power due to the failure of Breaker 8-15. Based on the Phase 2 evaluation, the inspection team determined that the finding was potentially risk significant due to the use of the counting rule. In reviewing the finding, the SRA evaluated the potential impact of the breaker failure on the initiating event frequency and performed a Phase 3 evaluation considering the actual impact on the initiating event frequency.

The review of the licensee's risk assessment of the event noted that the Bayesian updating of the LOOP frequency due to the breaker failure resulted in a very small increase in the initiating event frequency from 3.09E-2 to 3.96E-2. The SRA and inspection team incorporated these values into the site specific LOOP worksheet and determined the result was a finding of very low safety significance. The SRA also considered the potential impact due to external events and Large Early Release Frequency (LERF). External events and LERF were also found to be of very low risk significance. These results were also consistent with the licensee's evaluation of the issue which concluded the failure of Breaker 8-15 was of very low safety significance. Overall, the inspection team and SRA determined this issue was considered to be of very low safety significance, GREEN.

<u>Enforcement</u>: The inspection team did not identify a violation of regulatory requirements. The maintenance activities associated with the switchyard breakers were not covered by 10 CFR Part 50 or Technical Specifications. This issue was considered to be a finding of very low significance (FIN 05000249/2004009-01). The licensee entered the event into the corrective action program as Condition Report 219063.

b.3 Determination of Switchyard Configuration

Introduction: No findings of significance were identified.

Discussion: In April 2004, due to offsite power line maintenance work necessary to ensure summer electrical grid reliability, EED requested that Line 1223 be removed from service by the licensee to support maintenance and subsequent post maintenance testing.

The inspection team noted that in order to support the post maintenance testing of Line 1223, which occurred on May 5, 2004, Switchyard Breakers 8-9 and 9-10 were required to be opened (See Attachment 3 to this report for an offsite switchyard diagram). In April 2004, EED personnel determined and advised licensee operations personnel of the risks associated with two possible Unit 3 switchyard configuration scenarios based on EED reliability and risk studies, as required by EED procedures. Exelon Energy Delivery reliability studies assumed a line fault and subsequent line protective relay actuation, concurrent with a LBB relay actuation. When a LBB relay actuated, the breaker which did not open on a line fault protective relay actuation was isolated by the opening of all adjacent breakers.

The first scenario proposed by EED consisted of the Unit 3, 345 kV switchyard ring bus in the normal configuration with the cross-tie Breaker 4-8 to the Unit 2 switchyard ring bus open. Based on this scenario, the Unit 3 switchyard would have had the following configuration for Line 1223 testing: Breakers 4-8, 8-9, and 9-10 would have been open; and Breakers 8-15, 10-11, and 11-14 would have been closed. Exelon Energy Delivery determined for this configuration that the worst case scenario was a fault on either Lines 1222 or 8014, followed by actuation of the LBB relay for Breaker 11-14. Subsequent opening of adjacent breakers due to LBB relay actuation would have resulted in Breaker 8-15 opening and would have caused a loss of offsite power to the RAT TR-32 and an automatic Unit 3 scram on load rejection with a subsequent de-energization of Unit Auxiliary Transformer (UAT) TR-31. This would have resulted in a Unit 3 LOOP.

The second scenario proposed by EED consisted of closing Breaker 4-8 and opening Breaker 8-15. Based on this scenario, the Unit 3 switchyard would have had the following configuration for Line 1223 testing: Breakers 8-15, 8-9, and 9-10 would have been open; and Breakers 4-8, 10-11, and 11-14 would have been closed. Thus, offsite power to RAT TR-32 was provided through the Unit 2, 345 kV switchyard ring bus. Exelon Energy Delivery determined for this configuration that the worst case scenario was a fault on Line 0302, followed by actuation of the LBB relay for either Breakers 4-8 or 3-4. Subsequent opening of adjacent breakers due to LBB relay actuation would have resulted in either Breakers 3-4 or 4-8 opening and would have caused a loss of offsite power to the RAT TR-32 for Unit 3 and the RAT TR-22 for Unit 2. However, Unit 3 safety related loads would continue to have offsite power available through an automatic transfer of loads from the RAT TR-32 to the UAT TR-31; therefore a Unit 3 LOOP would not have occurred.

The inspection team determined that licensee operations personnel, after consultation with EED made the decision to implement the second Unit 3 switchyard scenario discussed above. Based on the worst case scenario provided by EED, the second scenario would have had Unit 3 safety related loads energized by offsite power. The inspection team reviewed and verified that the licensee assessed plant risk on

May 5, 2004, for planned maintenance activities on Unit 3 in accordance with licensee procedures and 10 CFR 50.65(a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

However, based on inspection team reviews of the reliability studies performed by EED and interviews with both licensee operations and EED personnel, the inspection team had the following observations concerning the licensee's decision making process surrounding the switchyard configuration:

- Exelon Energy Delivery personnel were required to assess the switchyard configurations utilizing a worst case scenario of a line fault concurrent with the failure of a breaker to open and subsequent LBB protective relay actuation (double failure scenario); however, licensee personnel did not consider evaluating the switchyard configurations utilizing the most probable single failure scenario and potential impact of switchyard breaker manipulation on 10 CFR 50 Appendix A, General Design Criterion 17;
- Exelon Energy Delivery personnel performed reliability studies on the final state of the proposed switchyard configuration; however, neither EED nor licensee personnel considered evaluating the risks associated with the implementation of the switching order and intermittent switchyard configurations, and potential breaker failures which may have occurred during switching operations;
- Licensee engineering and operations personnel did not attempt to evaluate the proposed switchyard configurations worst case scenarios provided by EED utilizing available probabilistic risk assessment tools;
- Exelon Energy Delivery personnel did not assess nor did licensee personnel inquire about the potential overduty of breakers in the switchyard during the momentary connection of both unit ring buses through the closure of the 4-8 breaker; and
- More formal communications concerning the proposed switchyard configurations may have assisted both parties in understanding each other's needs, requirements and evaluations.

The observations detailed above were evaluated by the licensee and the inspection team verified that the observations did not identify any additional adverse consequences associated with this specific event. Therefore the inspection team concluded that the observations associated with the licensee's determination of the switchyard configuration planning were minor in nature; however, the licensee initiated Condition Report 220656 to evaluate corrective actions to improve switchyard configuration assessment and planning.

.3 Review the Licensee's Performance with Emergency Preparedness Procedures and Communication to the NRC. In Particular, Review Communications Surrounding the Trip of the 2/3 Emergency Diesel Generator and the Licensee's Decision-Making Surrounding the Exit from the Notification of an Unusual Event

a. Inspection Scope

The inspection team evaluated the licensee's performance associated with implementation of the Emergency Plan and Emergency Plan Implementing Procedures. The inspection team also evaluated the communications and information received from the licensee during the event. Finally, the inspection team interviewed licensee personnel involved with responding to the event and reviewed the applicable emergency response procedures, operator logs, completed event notification forms and corrective action program documents.

b. Findings and Observations

Introduction: No findings of significance were identified.

Discussion: On May 5, 2004, at approximately 13:27, Dresden Unit 3 experienced an automatic reactor scram with a Group I, II, and III isolation, and a LOOP to the ECCS busses. At 13:42, approximately 15 minutes after the event occurred, the licensee Shift Manager, who was the Shift Emergency Director, declared a Notification of an Unusual Event. The Unusual Event Notification was made based on meeting the criteria for Dresden Emergency Action Level MU-1, "Unplanned Loss of All Offsite Power to a Unit's ECCS Busses." Notification to the State of Illinois of the Unusual Event declaration was made at 13:49 through the Nuclear Accident Reporting System. Notification to the NRC of the event was made at 14:12 through the Event Notification System. The NRC Region III Incident Response Center entered the Monitoring Mode following the licensee's declaration of the event. The inspection team verified that the initial notifications to the state and NRC accurately documented the initial conditions of the event.

Following restoration of offsite power to one safety-related ECCS bus at 16:01 on May 5, 2004, the Emergency Director terminated the Unusual event. Notification to the State of Illinois of the Unusual Event termination was made at 16:11 through the Nuclear Accident Reporting System. Notification to the NRC of the termination of the event was made at 16:46 through the Event Notification System.

The inspection team reviewed the circumstances surrounding the event and the licensee's emergency plan to verify that the appropriate event classification was made. In addition, the inspection team verified that the initial notifications made by the licensee to the state and NRC were performed in a timely manner. Through interviews with all the licensee personnel involved with the emergency declaration, the inspection team determined that approximately an hour and a half into the event, the Emergency Director, in consultation with the Emergency Preparedness Manager, and Acting Operations Manager, determined that upon the restoration of offsite power to one division of safety-related ECCS equipment, the event would be terminated. The inspection team verified that the criteria utilized for termination met the intent of licensee Procedures EP-AA-111, "Emergency Classification and Protective Action Recommendations," and EP-AA-115, "Termination and Recovery." In particular, the inspection team verified the termination criteria prescribed in Attachment 1 of Procedure EP-AA-111, "Termination/Recovery Checklist."

The inspection team noted that the licensee did not inform the NRC Region III Incident Response Center with the criteria for the termination of the event. However, the inspection team also noted that discussion of the termination criteria with the NRC was not required by NRC regulations nor licensee procedures. The licensee did discuss and coordinate with the NRC the communication needs of the NRC Region III Incident Response Center following the licensee's termination of the event, as required by licensee Procedure EP-AA-115.

The inspection team determined that while communications did occur in accordance with licensee procedures and NRC regulations, additional communications could have occurred which would have ensured the NRC Region III Incident Response Center was better informed of the events which had occurred. Most notably the inspection team determined the NRC Incident Response Center was not made aware of the following facts during the event:

- A manual breaker cross-tie was available during the entire event between Dresden Unit 2 and Unit 3, through the Unit 2 Reserve Auxiliary Transformer TR-22. The cross-tie was safety-related and capable of supplying offsite power to one Division of accident loads for Unit 3 and both Divisions of Safe-Shutdown loads for Unit 3;
- The Unit 2 Switchyard Ring Bus was affected during the initial stages of the event when Offsite Power Line 2311 and Transformer TR-81 were de-energized;
- Spent fuel pool cooling was lost for the spent fuel pool during the initial LOOP and was then subsequently restored approximately one hour later;
- The issues associated with the inability to close the Bus 34 to Bus 36 4160kV cross-tie breaker;
- The issues associated with the inadvertent restoration of offsite power to Busses 33-1 and 33 and the subsequent opening of the output breaker for EDG 2/3 at approximately 16:00 during the event; and
- The Shift Emergency Director decision which utilized licensee personnel already mobilized in the Outage Control Center as technical support during the event.

The inspection team concluded that the licensee's emergency response was conducted in accordance with the emergency plan and emergency plan implementing procedures. In addition, the inspection team concluded that the observations associated with communications to the NRC during the event were minor in nature; however, the licensee initiated Condition Report 219337 to initiate corrective actions to improve emergency response communications.

.4 Monitor and Assess the Licensee's Determination of the Root Cause of the Circumstances Surrounding the Trip of the 2/3 Emergency Diesel Generator Including Actions for Restoration of the Emergency Diesel Generator

a. Inspection Scope

The inspection team interviewed licensee personnel, and reviewed applicable procedures and corrective action program documents. In addition, the inspection team conducted walkdowns with licensee personnel of the emergency diesel generator and electrical busses. The inspection team also evaluated any component failures for extent of condition and common cause.

b. Findings and Observations

b.1 Description of Event

During the initial stages of the LOOP which occurred May 5, 2004, the automatic opening of Switchyard Breaker 10-11 caused the main generator to trip due to a Load Rejection. The loss of the main generator resulted in the fast transfer of busses normally supplied from the UAT TR-31. The fast transfer involved the opening of the normal supply breakers for Busses 31 and 33, and the automatic closing of the alternate supply breakers from the RAT TR-32. At this time, Bus 33 was energized from RAT TR-32, and the normal supply breaker for Bus 33 was in the "normal after close" position, since the last operator positioning of that breaker was in the closed position. Subsequently, since Breaker 8-15 failed to open, and a nondirectional time overcurrent protective relay required Breaker 8-15 to open, the LBB protection relay caused the feeder breakers downstream of RAT TR-32 to open. One of the downstream breakers was the alternate feed to Bus 33. This resulted in the de-energization of Bus 33 and Emergency Bus 33-1 which resulted in the start of the EDG 2/3 and the re-energization of Bus 33-1 by EDG 2/3. Because of the de-energization of Bus 33, the RAT TR-32 Undervoltage (UV) logic sealed in. Bus 33 was then re-energized by the operators per Procedure DGA-12, "Partial or Complete Loss of AC Power."

Automatic closure of the alternate feed breaker (from RAT TR-32) could only occur if two conditions were satisfied: 1) the normal feed breaker (from UAT TR-31) control switch was in "Normal after Close" position and the breaker was in the open position (tripped state); and 2) the RAT TR-32 UV logic was reset. In the state that the plant was in at this time, only the first condition was satisfied.

Later in the event, power was restored to RAT TR-32. After power was restored, the control room directed an operator to reset the RAT TR-32 UV logic per procedure DGA-12. Had the operator reset the TR-32 UV logic, the alternate feeder breaker to Bus 33 would have automatically closed, since both conditions for automatic closure of the breaker would have been satisfied. However, before the operator had a chance to reset the logic, the logic inadvertently reset itself which caused the alternate feeder breaker to Bus 33 to automatically close.

This automatic closure was not anticipated by the licensee operations personnel, and caused the reverse power trip of the EDG 2/3 output breaker which was also supplying power to Bus 33 at that time. Subsequent interviews conducted with the licensee operator responsible for resetting the UV logic by the licensee (immediately following the incident) and later by the inspection team revealed that the operator had not yet reset the logic circuitry. Subsequent immediate follow-up by licensee operations personnel identified that the inadvertent closure of the alternate feeder breaker to Bus 33 would have occurred had the operator had the opportunity to reset the logic per procedure DGA-12. The licensee's immediate evaluation of this issue identified that the DGA-12 procedure was not adequate in that there were no steps prescribed to prevent an inadvertent closure of the alternate feeder breaker to Bus 33.

Since the automatic closure of the breaker was not anticipated and the operator confirmed the logic was not reset per the procedure, the licensee performed troubleshooting activities to determine what equipment had failed. However, after investigating the probable component failures for the automatic breaker closure event, the licensee could not identify any immediately failed components. Therefore, the licensee attributed the failure to a chattering contact in the undervoltage auxiliary HFA relay used to seal-in the UV logic. Since a momentary chatter of this contact would have caused the UV logic to reset, the licensee concluded that this was the most probable cause for the inadvertent energization of Bus 33. As additional corrective actions, the licensee replaced the undervoltage auxiliary HFA relay, quarantined the suspect HFA relay, and made plans to send the relay offsite for further failure analysis by the vendor. The inspection team concluded that the licensee's immediate and planned corrective actions for this issue were reasonable.

As a result of the reverse power trip of the EDG 2/3 output breaker, the licensee developed and implemented a troubleshooting plan to determine the condition of EDG 2/3. The troubleshooting plan included meggering of the EDG windings, visual inspections of the generator and EDG output breaker, and testing of the EDG output breaker reverse power trip device to ensure EDG 2/3 remained operable. The inspection team reviewed the troubleshooting plan and test results and determined the licensee's corrective actions to evaluate the status of EDG 2/3 were comprehensive.

b.2 Findings and Observations

Introduction: A Green self-revealed finding was identified involving a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, for the failure to incorporate appropriate procedure steps to prevent the inadvertent automatic closure of the alternate feeder breaker to Bus 33, upon restoration of offsite power.

Description: During the LOOP on May 5, 2004, power was lost to both the normal power supply through UAT TR-31 and the alternate power supply through RAT TR-32 for the 4kV Bus No. 33. Because of the de-energization of Bus 33, the RAT TR-32 UV logic was sealed in. Bus 33 was then re-energized from EDG 2/3 per procedure DGA-12, "Partial or Complete Loss of AC Power."

After power was restored, the control room operators directed an operator to reset the RAT TR-32 UV logic per procedure DGA-12. However, before the operator had a chance to reset the logic, the logic inadvertently reset itself which caused the alternate feeder breaker to Bus 33 to automatically close. This automatic closure was not anticipated by the Dresden operations personnel, and led to the reverse power trip of the 2/3 EDG output breaker which supplied power to Bus 33 at that time. The licensee determined that this automatic closure was most probably due to the failure of the TR-32 under-voltage auxiliary relay. Immediate follow-up by licensee personnel determined that had the operator reset the RAT TR-32 UV logic, the alternate feeder breaker to Bus 33 would have automatically closed, since both conditions for automatic closure of this breaker were satisfied at that time.

While the failure was attributed to component failure, the alternate feeder breaker to Bus 33 would have inadvertently closed had the operator performed the prescribed bus restoration steps for Bus 33 as delineated in Procedure DGA-12. During the licensee's initial follow-up evaluation of this issue, licensee personnel discovered that the procedure directed operations personnel to reset the RAT TR-32 undervoltage logic without requiring that the normal feed control switch was in a position other than the "normal after close" position. The normal feed control switch positioned the normal feeder breaker (from UAT TR-31) for Bus 33. With both the breaker in the "normal after close" position and the logic reset, the alternate feeder breaker met both required permissives for automatic closure. The licensee immediately resolved this deficiency by adding steps in Procedure DGA-12 that required the normal feed control switch to be placed in the "pull to lock" position which precluded the alternate feeder breaker from automatically closing when the UV logic was reset.

Analysis: The inspection team determined that the self-revealed failure to assure that appropriate procedure conditions and criteria were prescribed to satisfactorily allow restoration of offsite power to Bus 33 was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on June 20, 2003. This finding was associated with the availability of a mitigating system and affected the mitigating cornerstone attribute of procedure quality and the objective to ensure the availability and capability of systems that respond to initiating events to prevent undesirable consequences. Therefore the inspection team determined this self-revealed finding was more than minor.

The inspection team completed a significance determination of this finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." The inspection team determined from the mitigating systems evaluation in the Phase 1 Screening Worksheet that all the questions were answered "No," therefore the finding was determined to be of very low safety significance (Green).

Enforcement: 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures, and Drawings, states, in part, that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and that the procedures shall include appropriate quantitative or qualitative acceptance criteria for determining that important activities have been satisfactorily accomplished.

Contrary to the above, the licensee failed to assure that the procedure which prescribed restoration of offsite power, an activity affecting quality, was appropriate to the circumstances and included the appropriate criteria to satisfactorily restore offsite power to Bus 33 without causing an inadvertent reverse power trip of EDG 2/3. Specifically, Procedure DGA-12, "Partial or Complete Loss of AC Power," did not contain steps to prevent the inadvertent automatic closure of the alternate feeder breaker to Bus 33 while EDG 2/3 was also supplying power to Bus 33. As an immediate corrective action, licensee personnel revised Procedure DGA-12 to correct this deficiency. Because this violation of 10 CFR 50, Appendix B, Criterion V was of very low safety significance and was entered into the licensee's corrective action program as Condition Reports 219063 and 219071, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 050-249/200409-02).

.5 Monitor and Assess the Licensee's Efforts to Evaluate the Inability of the Standby Gas Treatment System to Maintain the Proper Differential Pressure in Secondary Containment

a. Inspection Scope

The inspection team evaluated the licensee's identification of the issue, initial actions to mitigate the consequences of the issue, and subsequent actions to restore the required vacuum to secondary containment. The inspection team also evaluated any component failures for extent of condition and common cause. The inspection team interviewed plant personnel, performed system walkdowns, and reviewed operator logs, licensee procedures and corrective action program documents related to the standby gas treatment system.

b. Findings and Observations

Introduction: A Green self-revealed finding was identified involving an inadequate secondary containment leak rate test procedure which resulted in a Non-Cited Violation of Technical Specification 3.6.4.1 for an inoperable secondary containment when the drywell purge fans were operating.

Discussion: On May 5, 2004, following the scram and Group II isolation on Unit 3, the standby gas treatment system automatically initiated and the reactor building ventilation isolated. However, the secondary containment differential pressure could not be maintained greater than or equal to the Technical Specification value of 0.25 inches of water gauge vacuum (after initiation differential pressure was 0.22 inches of water).

Because Unit 2 was in a forced outage to replace Recirculation Pump Motor 2A, both Unit 2 drywell purge fans were running to provide ventilation for the drywell. The Unit 2 drywell purge fans discharged air at approximately 11,000 standard cubic feet per minute (scfm) into a common header near the inlet to the standby gas treatment system in the turbine building. The standby gas treatment system drew approximately 4,400 scfm off the common header. The remaining flow was returned to the reactor building through the reactor building ventilation system exhaust ducts. Complicating matters, the Drywell Purge Filter Housing 2A had deteriorated, allowing significant air in-leakage from the turbine building. The inspection team verified that the drywell purge system was not safety-related and that there was no requirement to inspect and maintain the filter housing. The Unit 3, Group II isolation signal isolated the Unit 3 drywell purge system but did not isolate the Unit 2 drywell purge system. Conversely, the Unit 2, Group II isolation signal isolated the Unit 2 drywell purge system but did not isolate the Unit 3 drywell purge system. The Unit 2 drywell purge fans were secured approximately two hours into the May 5, 2004, event and differential pressure subsequently reached 0.31 inches of water gauge vacuum.

After follow-up questioning by the inspection team, the licensee also identified that the reactor building ventilation and refueling floor radiation monitors did not isolate the opposite unit's drywell purge system (to provide secondary containment isolation from airborne contamination or a refueling accident).

The inspection team also concluded that the Secondary Containment Leak Rate Test Procedure DTS 1600-22 which implemented Technical Specification Surveillance Requirement 3.6.4.1.3, to verify secondary containment can be maintained greater than or equal to 0.25 inches of vacuum, did not test the configuration with the opposite unit's drywell purge system operating. In fact, the third step of Procedure DTS 1600-22 was to stop the Unit 2 and 3 drywell purge fans if operating. Subsequent to the inspection, the licensee completed the root cause analysis report. The licensee determined the root cause to be a degraded secondary containment boundary which was not detected due to an inadequate secondary containment leak rate test procedure.

The licensee also identified several contributing causes which the inspection team verified after the inspection was completed. In February 1991, the licensee completed a modification to the standby gas treatment system initiation logic to provide a trip of the reactor building ventilation fans and closure of the reactor building isolation dampers on both units following a standby gas treatment system initiation signal from either unit. Prior to this modification, a standby gas treatment system initiation signal from one unit would result in the trip of the reactor building ventilation fans and closure of the reactor building isolation dampers only on that unit. A Dresden problem identification form was initiated in November 1997, which questioned the need to trip the opposite unit's drywell purge fans following a secondary containment isolation initiating from either unit. System engineering incorrectly concluded that a change in the standby gas treatment system initiation logic was not warranted since the as-built configuration met the current electrical schematics. The disposition also incorrectly concluded that the drywell purge fan operation on the unit without the standby gas treatment system initiation would not result in airflow into the reactor building. Other contributing causes identified by the licensee included inadequate drywell purge system preventive maintenance due to the failure to recognize that the system was within the secondary containment boundary; and installation of the drywell purge fan train A and B filter housings with only a three-inch gap which hindered effective maintenance of the filter access panels.

Analysis: The inspection team determined that the self-revealed failure to maintain secondary containment operable under all conditions was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on June 20, 2003. The inspection team determined this finding was greater than minor because if left uncorrected the deficiency would become a more significant safety concern. This self-revealed finding was associated with the Barrier Integrity cornerstone objective to provide reasonable assurance that containment protects the public from radionuclide releases caused by accidents or events.

The inspection team completed a significance determination of this finding using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations." Because the finding only represented a degradation of the radiological barrier function of secondary containment, the inspection team answered "Yes" to the first question in the containment barriers column of the Phase 1 Screening Worksheet; and therefore, concluded that the finding was of very low safety significance (Green).

Enforcement: Technical Specification 3.6.4.1 requires, in part, that secondary containment be operable in Modes 1, 2, and 3, during moving of fuel assemblies in the secondary containment, during core alterations, and during operations with the potential for draining the reactor vessel. Contrary to the above, secondary containment was not operable on either unit while in those conditions while the opposite unit's drywell purge fans were operating. Specifically, secondary containment was inoperable on May 5, 2004, while Unit 3 was in Mode 1 and the Unit 2 drywell purge fans were operating. As an immediate corrective action, the Alarm Response Procedure DAN 923-5 C-1 was revised to secure any running drywell purge fans if reactor building ventilation had tripped and isolated. In addition, Work Request 143854 was also initiated to repair the in-leakage to the drywell purge filter housings. Because this violation of Technical Specification 3.6.4.1 was of very low safety significance and was entered into the licensee's corrective action program as Condition Reports 219269 and 219346, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000249/2004009-03).

.6 Monitor and Assess the Licensee's Determination of the Root Cause and the Circumstances Surrounding the Inability to Restore Power to Bus 36 and to Restore a Condensate Pump

a. Inspection Scope

The inspection team evaluated the licensee's identification of the event, initial actions to mitigate the event, and subsequent actions to restore power to Bus 36. The inspection team also evaluated any component failures for extent of condition and common cause. The inspection team interviewed plant personnel and reviewed vendor manuals, operator logs, maintenance procedures, common cause analysis reports and corrective action program documents.

b. Findings and Observations

Introduction: No findings of significance were identified.

Discussion: During the initial stages of the LOOP event on May 5th, Bus 36 was unable to be re-energized due to the failure of the 4kV cross-tie breaker from Bus 34 to Bus 36 to close when actuated. As designed, this breaker opened automatically to load shed once the Station Blackout Diesel was manually tied on to energize Bus 34. However, the breaker would not close when the off-normal procedure for the LOOP prescribed that the 480-Volt Busses 35, 36 and 37 be re-energized.

Following the Unit 3 scram, HPCI was used for reactor water level control. When utilized for this application, the HPCI system required constant attention and manipulation by the reactor operator at the controls to maintain reactor water level within the desired band. For this reason, the preferred method of core cooling was via the feedwater and condensate system. However, Bus 36 provided power to Feedwater Inlet Isolation Valves 3A and 3B which were necessary to properly fill and vent the condensate system. Because the feedwater and condensate systems were lost as a result of the LOOP, the reactor operators were appropriately concerned that due to the subsequent system drain down, a restart of these systems would result in a water hammer event. For this reason, the reactor operators appropriately delayed the return of the condensate system to service until Bus 36 was re-energized so that a fill and vent of the system could be performed.

In response to the breaker failure, licensee electrical maintenance personnel were dispatched to locally observe the second attempted closure of the Bus 34, 4kV cross-tie breaker in an attempt to determine if the issue was with the breaker or due to breaker racking issue. When the licensee preliminarily determined that the breaker was at fault, the existing breaker was replaced with a qualified spare breaker. The installed spare breaker was subsequently closed, which re-energized Bus 36 with no further complications. Licensee personnel quarantined the failed breaker and performed troubleshooting which was unable to reproduce the failure which had occurred. The inspection team reviewed the licensee troubleshooting plan results which also included performance of the four-year preventive maintenance inspection with no significant problems noted. Due to the licensee's inability to initially determine the root cause of the breaker failure, the breaker was awaiting vendor analysis. The inspection team concluded that the licensee's immediate actions to attempt to determine the cause of the breaker failure were appropriate.

The inspection team also reviewed a Common Cause Analysis (CCA) Report generated by the licensee which specifically analyzed all 4kV breaker failures at Dresden from January 1, 2003, to February 29, 2004. The CCA did not reveal a common cause of failure due to a lack of adequate historical data concerning the as-found condition of failed breakers.

Prior to September 9, 2003, the licensee's initial troubleshooting procedure for a failed breaker directed licensee personnel to re-rack a breaker that had failed to properly operate. Although this practice typically resulted in the breaker's subsequent operation, this practice masked or destroyed any evidence of the as-found condition. This procedural inadequacy had previously been identified as a Green Non-Cited Violation by the NRC in a Safety System Design Inspection documented as Non-Cited Violation Numbers 05000249/2003008-04 and 05000237/2003008-04 in August 2003. Since the initiation of the corrective actions for this Non-Cited Violation, the inspection team noted there had been five failures of the same model breaker. The Inspection team verified that three of the failure causes were diagnosed during the as-found troubleshooting, and that none of the causes were similar. The remaining two breaker failure modes, which included the failure during this event, have not been identified through the initial troubleshooting efforts of the licensee and were awaiting vendor analysis as part of the root cause evaluation.

The inspection team concluded that the licensee's immediate corrective actions for this issue were adequate and that the planned corrective actions appeared appropriate and will assist in determining the root cause of this failure.

.7 Evaluate the Licensee's Efforts to Determine the Extent of Condition for Root Causes Identified in the Other Charter Items

a. Inspection Scope

The inspection team evaluated the licensee's efforts to determine the extent of condition for the initial and root causes for the issues identified in the Inspection Charter. The reviews and evaluations were performed as the inspection team inspected each of the Charter items. At the end of the Special Inspection, the licensee continued to perform the root cause evaluations for the event and individual Charter items.

As part of this inspection, the inspection team interviewed licensee and EED personnel, reviewed the plant's Technical Specification and Updated Final Safety Analysis Report, operator logs, maintenance procedures and corrective action program documents generated as a result of this event.

b. Findings and Observations

Introduction: No findings of significance were identified.

Discussion: The inspection team determined that the licensee's response to the events which occurred as a result of the May 5, 2004, LOOP, including the additional unexpected procedure issues and equipment responses which occurred, was appropriate. The inspection team verified that for the event and issues which occurred, licensee personnel addressed the immediate extent of conditions for each issue and implemented remedial corrective actions to address the issues. With respect to the equipment issues which occurred and there was no immediate determination of the cause of the failure, the inspection team verified that the licensee captured the scope of issues to be performed in the corrective action program to further assess the cause.

In addition, the inspection team verified the licensee appropriately quarantined the subject equipment for further inspection by either licensee personnel or vendor experts. Finally, the inspection team verified that remedial corrective actions the licensee implemented addressed the extent of condition, until the licensee could complete the formal root cause evaluations and implement long term corrective actions, in accordance with the licensee's corrective action program.

4OA6 Meetings

Exit Meetings

On May 14, 2004, the inspection team presented the preliminary inspection results to Mr. D. Bost and other members of Dresden plant management and staff. The licensee acknowledged the information and findings presented. The inspection team asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION
SPECIAL INSPECTION TEAM CHARTER
DRESDEN OFFSITE SWITCHYARD DIAGRAM

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Exelon Generation Company, LLC

D. Bost, Site Vice President
J. DeYoung, Corporate Emergency Planning Specialist
E. Flick, Senior Manager Plant Engineering
R. Gadbois, Shift Operations Superintendent
D. Galanis, Design Engineering Manager
J. Griffin, Regulatory Assurance - NRC Coordinator
J. Hansen, Regulatory Assurance Manager
P. Karaba, Electrical Design Engineering Manager
R. Lopriore, Vice President Operations Support
P. Quealy, Emergency Preparedness Manager
R. Rybak, Acting Regulatory Assurance Manager
J. Sipek, Nuclear Oversight Director
B. Svaleson, Maintenance Director
M. Tucker, Corporate Electrical Engineering
D. Wozniak, Plant Manager

Exelon Energy Delivery

F. Marquez, Vice President Exelon Energy Delivery

U.S. Nuclear Regulatory Commission

P. Hiland, Acting Deputy Director, Division of Reactor Projects
M. Ring, Chief, Division of Reactor Projects, Branch 1
M. Banerjee, Project Manager - Dresden, Office of Nuclear Reactor Regulation
M. Sheik, Resident Inspector, Dresden Resident Inspector Office
M. Parker, Senior Reactor Analyst, Division of Reactor Safety

IEMA

R. Schulz, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000249/2004009-01	FIN	Green. Self -revealed failure to perform the appropriate preventive and corrective maintenance on Switchyard Breaker 8-15 which resulted in the failure of Breaker 8-15 to open and subsequent Unit 3 automatic scram and Loss of Offsite Power.
05000249/2004009-02	NCV	Green. Self-revealed failure involving a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, for the failure to incorporate procedure steps to prevent the inadvertent automatic closure of the alternate feeder breaker to Bus 33, upon restoration of offsite power.
05000249/2004009-03	NCV	Green. Self-revealed failure involving an inadequate secondary containment leak rate test procedure which resulted in a Non-Cited Violation of Technical Specification 3.6.4.1 for an inoperable secondary containment when the drywell purge fans were operating.

Closed

05000249/2004009-01	FIN	Green. Failure to perform the appropriate preventive and corrective maintenance on Switchyard Breaker 8-15 which resulted in the failure of Breaker 8-15 to open and subsequent Unit 3 automatic scram and Loss of Offsite Power.
05000249/2004009-02	NCV	Green. Self-revealed failure involving a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, for the failure to incorporate procedure steps to prevent the inadvertent automatic closure of the alternate feeder breaker to Bus 33, upon restoration of offsite power.
05000249/2004009-03	NCV	Green. Self-revealed failure involving an inadequate secondary containment leak rate test procedure which resulted in a Non-Cited Violation of Technical Specification 3.6.4.1 for an inoperable secondary containment when the drywell purge fans were operating.

Discussed

None

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 219372; Main Steam Pressure Oscillation Following Group I; May 5, 2004

CR 219361; ATWS RPT Instrumentation INOP due to field breaker failure; May 5, 2004

CR 219343; IRM 13 generated an unexpected 'Inop' ½ scram; May 6, 2004

CR 219341; CT's located in 4kV bus 33-1 cub. 14 (2/3 EDG) inspection; May 5, 2004

CR 219337; Termination from Unusual Event; May 5, 2004

CR 219332; Documentation of Release from Unit 3 Isolation Condenser; May 5, 2004

CR 219294; Security DG Trip; May 6, 2004

CR 219269; Reactor Bldg dP limit exceeded; May 5, 2004

CR 219263; 3B Condensate Prefilter Valve would not close; May 5, 2004

CR 219192; Loss of Back-up Power for Security; May 6, 2004

CR 219187; HPCI 2301-45 vlv flange bolting torque; May 6, 2004

CR 219071; TR32 closed into Bus 33. Prior to BUS UV resets; May 5, 2004

CR 219070; Unplanned Entry into TLCO for inoperable conductivity monitor; May 5, 2004

CR 219059; SRM Channel 24 reading high; May 5, 2004

CR 219020; Additional Crack Found in Bottom Panel of U3 EDG Air Box; May 5, 2004

CR 218812; "B" SBGT trouble during ESS Bus Transfer; May 5, 2004

CR 218173; Crack found in Unit 3 EDG Air Box; May 1, 2004

CR 219346; Following U3 Scram, Inadequate Secondary Containment Differential Pressure

CR 219269; Reactor Building dP Exceeded

CR 221610; Reactor Building dP Low due to Degraded Filter Housing

CR 219063; Switching Fault Cause LOOP/Scram/Group I, II & III on U3; May 5, 2004

CR 220656; Impact of Switchyard Breaker Manipulation on GDC 17 Compliance; May 12, 2004

AR 00172179; Procedure Revision Required to Aid in Performance Monitoring; August 19, 2003

AR 00173092; 4kV Horizontal Breaker Failures; August 26, 2003

ATI 173092-03; Common Cause Analysis Report for 4kV Horizontal Breaker Failures; March 22, 2004

AR 00219381; Equipment Failures During U3 SCRAM; May 7, 2004

AR 00220338; No Record of when U3 SBO Secured following LOOP on 5/5/04

Drawings

M-269; Unit 2 Diagram of Reactor Building Ventilation

M-25; Unit 2 Pressure Suppression Piping

M-49; Unit 2 and 3 Standby Gas Treatment System

12E-2400C; Schematic Diagram Standby Gas Treatment System

262001-001; AC Distribution; Revision 2

26203-002; 345 kV Switchyard; Revision 0

12E-2328; Single Line Diagram, Emergency Power System; Revision M

12E-3342; Schematic Diagram, 4160 V Bus 33 Main & Reserve Feed GCB's; Revision X

12E-3343; Schematic Diagram, 4160 V Bus 34 Main & Reserve Feed GCB's; Revision Y

12E-3305; 480V Switchgears 35, 36 & 37; Revision BB

12E-3303; 4160V Switchgears 31, 32 & 34; Revision R

262001-001; AC Distribution; Revision 02

Procedures

DTS 1600-22; Secondary Containment Leak Test; Revision 20

DOP 1600-07; Primary Containment Deinerting; Revision 17

DGA-12; Partial or Complete Loss of AC Power; Revision 47

DGA-12; Partial or Complete Loss of AC Power; Revision 48

MP-4.2.2.1.2-A; 362 kV Model “C” Type “GA” Gas Circuit Breaker Routine Maintenance Inspection; Revision 2

SA-AA-129; Electrical Safety; Revision 2

MA-AB-725-117; Preventive Maintenance and Receipt Inspection on Merlin Gerin SF6 4kV AMHG Circuit Breakers; Revision 1

EP-AA-115; Termination and Recovery; Revision 3

EP-AA-111; Emergency Classification and Protective Action Recommendations; Revision 7

Vendor Manuals

ABB Product Advisory; ITE GA and GB Circuit Breakers; July 2003

IB 9201; Instruction and Maintenance Manual for Model AMHG SF6 Circuit Breaker; August 14, 1997

Instruction Manual for Power Circuit Breakers SF6 Model C Type 362GA 63-20/30 Transmission Class

Work Requests/Work Orders

WO 99067555; 4 Year Preventive Maintenance Inspect 4kV Breaker UTC 0001185092; December 02, 2002

WO 00495950-01; 4 Year Preventive Maintenance Inspect 4kV Breaker UTC 0001185092; May 6, 2004

WO 00694303-01; Troubleshoot Problem with Reenergizing Breaker; May 5, 2004

Exelon Energy Delivery Switchyard Breaker Work Orders and Performance Tests

WO 99212382; Dresden 2/3 Annual Preventive Maintenance Perform Lube/Inspection; BUS-TIE 8-15 Perform Lube/Inspect

Breaker Performance Results; BUS TIE 6-7; 03/26/98 at 10:26:45

Breaker Performance Results; BUS TIE 6-7; 03/26/98 at 10:36:39

Breaker Performance Results; BUS TIE 6-7; 03/26/98 at 10:50:53

Breaker Performance Results; BUS TIE 8-15; 09/9/98 at 11:28:16

Breaker Performance Results; BUS TIE 8-15; 09/9/98 at 12:03:17

Breaker Performance Results; BUS TIE 8-15; 09/9/98 at 12:17:35

Breaker Performance Results; BUS TIE 8-15; 09/9/98 at 12:39:07

Breaker Performance Results; BUS TIE 6-7; 10/23/01 at 11:06:41

Breaker Performance Results; BUS TIE 6-7; 10/23/01 at 11:14:23

Breaker Performance Results; BUS TIE 6-7; 10/23/01 at 11:20:15

Breaker Performance Results; BUS TIE 6-7; 10/23/01 at 13:18:10

Breaker Performance Results; BUS TIE 6-7; 10/23/01 at 13:26:12

Breaker Performance Results; BUS TIE 6-7;10/23/01 at 13:30:25

Breaker Performance Results; BUS TIE 6-7;10/23/01 at 13:36:16

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:16:19

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:21:17

Breaker Performance Results; BUS TIE 8-15;03/27/02 at 09:29:40

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:36:01

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:41:17

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:41:17

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 09:47:43

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 10:00:43

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 10:03:08

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 10:53:48

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 11:50:07

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 11:54:04

Breaker Performance Results; BUS TIE 8-15; 03/27/02 at 11:59:07

Breaker Performance Results; BUS TIE 8-15; 3/27/02 at 12:11:29

Breaker Performance Results; BUS TIE 6-7; 10/04/03 at 12:57:39

Breaker Performance Results; BUS TIE 6-7; 10/04/03 at 14:24:49

Breaker Performance Results; BUS TIE 6-7; 10/04/03 at 14:31:49

Breaker Performance Results; BUS TIE 6-7; 10/04/03 at 14:33:54

<u>Other Documents</u>

Commonwealth Edison Correspondence to the NRC dated 8/22/85; Dresden Station Units 2 and 3 Auto-Transfer of Auxiliary Power Feeds; NRC Dockets Nos. 50-237 and 50-249

Commonwealth Edison Correspondence to the NRC dated 9/11/85; Licensee Event Report 85-034-0, Docket 050237; Low Reactor Water Level Scram During Loss of Offsite Power

Commonwealth Edison Correspondence to the NRC dated 12/13/85; Dresden Station Units 2 and 3 Compliance with 10 CFR 50 Appendix A - General Design Criterion No. 17

Commonwealth Edison Correspondence to the NRC dated 12/31/85; Dresden Station Unit 2 Reliability of Offsite Power; NRC Docket No. 50-237

NRC Correspondence to Commonwealth Edison dated 12/16/86; Dresden Units 2 and 3 Compliance with GDC-17 (TAC 60944, 60945)

DAN 923-5 C-1; Reactor Building Differential Pressure Lo; Revision 14

Technical Specification 3.6.4.1; Secondary Containment

EC 349101; Standby Gas Treatment Interaction with Drywell Vent Purge System

Operability Evaluation 04-010; Secondary Containment Degraded While Drywell - Torus Purge is in Operation; Revision 0

Safety Evaluation Report dated October 17, 1969; Safety Evaluation for Dresden Nuclear Power Station, Unit 2, Docket No. 50-237; October 17, 1969

Safety Evaluation Report dated March 30, 2001; Safety Evaluation Related to Amendment No. 185 to Facility Operating License No. DPR-19 and Amendment No. 180 to Facility Operating License No. DPR-25; March 30, 2001

D3F46 Startup Plant Operations Review Committee Minutes; May 7, 2004

Event Notification Worksheet; Event Number 40727; May 5, 2004

Shift Manager and Operator Logs from May 1 through May 6, 2004

Prompt Investigation Report for Condition Report Number 219063

Sequence Events Recorder printouts for May 5, 2004

SA-1309; Risk Assessment of Switchyard Alignments with Transmission Line 1223 Unavailable

Licensee Event Report 89-001-01; Turbine Trip and Reactor Scram on Stop Valve Closure Due to Slow Transfer of House Loads During Loss of Offsite Power

LIST OF ACRONYMS USED

ABB	Asea, Brown and Boveri
AC	Alternating Current
CCA	Common Cause Analysis
CDT	Central Daylight Time
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EED	Exelon Energy Delivery
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
kV	kiloVolt
LBB	Local Breaker Backup
LERF	Large Early Release Frequency
LOOP	Loss of Offsite Power
NARS	Nuclear Accident Reporting System
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OA	Other Activities
RAT	Reserve Auxiliary Transformer
scfm	Standard Cubic Feet per Minute
SDP	Significance Determination Process
SF_6	Sulfur Hexafluoride
SRA	Senior Reactor Analyst
UAT	Unit Auxiliary Transformer
UFSAR	Updated Final Safety Analysis Report
UV	Undervoltage

May 6, 2004

MEMORANDUM TO: Robert Krsek, Senior Resident Inspector, Kewaunee
Division of Reactor Projects

FROM: Mark Ring, Chief, Branch 1 ***/RA/***
Division of Reactor Projects

SUBJECT: SPECIAL INSPECTION FOR ANOMALIES AT DRESDEN FOLLOWING THE MAY 5, 2004, LOSS OF OFFSITE POWER

On May 5, 2004, at about 13:27 (CDT), Unit 3 at the Dresden Nuclear Power Plant was operating at full power when a Loss of Offsite Power (LOOP) event occurred during activities to reconfigure breakers in the plant switchyard. An automatic scram occurred due to the LOOP. All control rods fully inserted and the emergency diesel generators started and successfully supplied power to the vital buses. The licensee declared an Unusual Event at 13:52 (CDT). Offsite power was restored to one safety bus, an emergency diesel generator and the station blackout diesel generator were supplying two other buses and the Unusual Event was terminated at 1601 (CDT) on May 5, 2004.

During the event and subsequent recovery, certain anomalous conditions were identified that were not fully understood including: upon opening switchyard breaker 8-15 a faulted condition occurred which resulted in also opening switchyard breaker 4-8 and precipitating the LOOP; following the LOOP the standby gas treatment system started, but was unable to maintain the proper differential pressure in secondary containment resulting in the need to enter the Technical Specification action statement; during preparations for restoring offsite power to bus 33, the feeder breaker from offsite closed onto the bus before it was intended and resulted in the tripping of the swing emergency diesel generator; and initially the licensee was unable to restore bus 36 to power a condensate pump.

Based on the criteria specified in Management Directive 8.3 and Inspection Procedure 71153, a Special Inspection was initiated in accordance with Inspection Procedure 93812 and Regional Procedure RP-1219. The Special Inspection will be performed by yourself (inspection lead), Bob Daley, DRS Inspector, Paul Pelke, Acting Project Engineer in DRP Branch 1, and Rob Ruiz, Reactor Engineer. The Special Inspection will evaluate the facts, circumstances, and licensee actions surrounding the noted anomalous conditions. A Charter was developed and is attached. The inspection will start on May 6, 2004.

Attachment: As stated

cc w/att: R. Daley, RIII
R. Ruiz, RIII
P. Hiland, DRP
S. Reynolds, DRP
P. Pelke, DRP
M. Banerjee, NRR
T. Reis, NRR

SPECIAL INSPECTION (SI) CHARTER

This Special Inspection is chartered to assess the circumstances surrounding anomalous conditions noted during the Unusual Event declaration at Dresden due to a Loss of Offsite Power (LOOP) on May 5, 2004. The conditions involved manipulation of breakers in the switchyard which caused the event, the inability of standby gas treatment to maintain the proper differential pressure in secondary containment, the unexpected closing of the offsite feeder breaker onto a bus being fed by the 2/3 emergency diesel generator (EDG) and the resultant trip of the 2/3 EDG, and the inability to power bus 36 to restore a condensate pump. The Special Inspection should:

18. Establish a sequence of events including event notification and classification.

19. Monitor and assess the licensee's determination of the root cause of the LOOP event, human performance, equipment performance, and adequacy of procedures.

20. Review the licensee's performance with emergency preparedness procedures and communication to the NRC. In particular, review communications surrounding the trip of the 2/3 EDG and the licensee's decision-making surrounding the exit from the UE.

21. Monitor and assess the licensee's determination of the root cause of the circumstances surrounding the trip of the 2/3 EDG including actions for restoration of the EDG.

22. Monitor and assess the licensee's efforts to evaluate the inability of the standby gas treatment system to maintain the proper differential pressure in secondary containment.

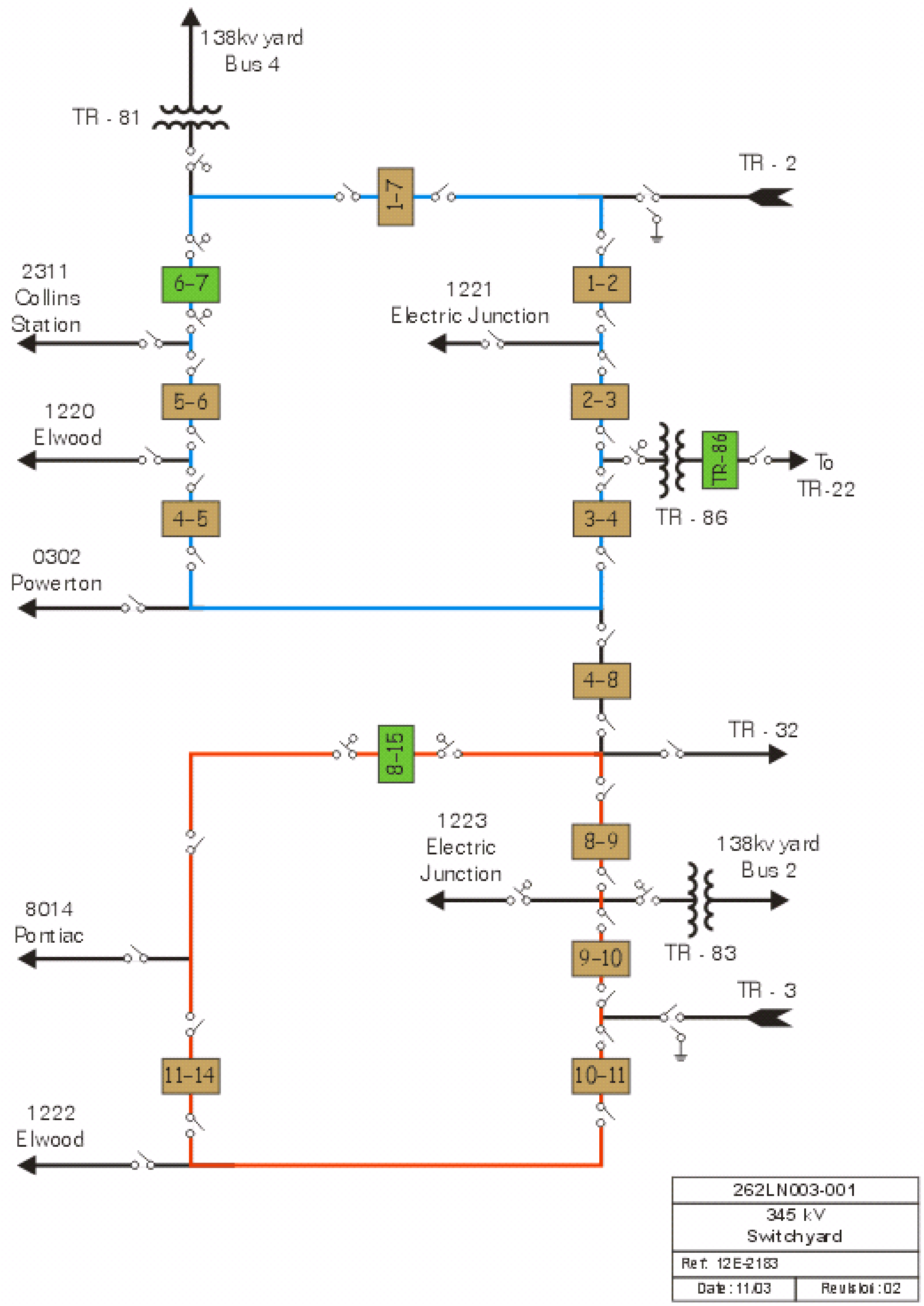
23. Monitor and assess the licensee's determination of the root cause and the circumstances surrounding the inability to restore power to bus 36 and to restore a condensate pump.

24. Evaluate the licensee's efforts to determine the extent of condition for root causes identified above.

Charter Approval

/RA/ Chief, Reactor Project Branch 1

/RA/ Acting Director, Division of Reactor Projects



Attachment 3