October 30, 2003

EA-03-163

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
NRC INTEGRATED INSPECTION REPORT 05000237/2003007;
05000249/2003007

Dear Mr. Skolds:

On September 30, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed integrated inspection report documents the inspection findings which were discussed on October 8, 2003, with Mr. R. Hovey 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 personnel.

Based on the results of this inspection, there were two NRC-identified and two self-revealed findings of very low significance. All four findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these findings as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. Additionally, licensee identified violations which were determined to be of very low safety significance are listed in Section 4OA7 of this report. If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the Resident Inspector Office at the Dresden Nuclear Power Station.

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Sincerely,

/RA by Patrick L. Hiland Acting for/

Mark Ring, Chief
Branch 1
Division of Reactor Projects

Docket Nos. 50-237; 50-249
License Nos. DPR-19; DPR-25

Enclosure: Inspection Report 05000237/2003007; 05000249/2003007
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Dresden Nuclear Power Station
Dresden Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Dresden
Chief Operating Officer
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-237; 50-249
License Nos:	DPR-19; DPR-25
Report No:	05000237/2003007; 05000249/2003007
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	6500 North Dresden Road Morris, IL 60450
Dates:	July 1 through September 30, 2003
Inspectors:	D. Smith, Senior Resident Inspector P. Pelke, Resident Inspector M. Mitchell, Reactor Engineer M. Sheikh, Reactor Engineer D. Chyu, Reactor Engineer R. Alexander, Radiation Specialist C. Phillips, Senior Operations Engineer R. Winter, Reactor Inspector R. Schulz, Illinois Emergency Management Agency
Observer:	Liliana Ramadan, NRC Intern
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000237/2003007, 05000249/2003007; 07/01/2003 - 09/30/2003, Dresden Nuclear Power Station, Units 2 and 3; Fire Protection, Event Followup, Other Activities.

This report covers a 3-month period of baseline resident inspection, and announced baseline inspections on licensed operator requalification and radiation safety. The inspection was conducted by Region III inspectors and resident inspectors. Four Green findings, all involving Non-Cited Violations (NCVs), were identified. 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 a assigned 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 involving a Non-Cited Violation of Technical Specification 5.4.1 was identified for the failure of an instrument maintenance supervisor to follow the fire prevention procedure and obtain permission from the fire marshal prior to an instrument technician performing hot work. This human performance deficiency resulted in the automatic initiation of the halon system in the auxiliary electric equipment room. Corrective actions by the licensee included establishing a continuous fire watch, refilling all halon bottles, briefing of this event with all instrument maintenance personnel, and coaching of individuals in accordance with station policy.

  The finding was more than minor because it affects the initiating events cornerstone objective to limit the likelihood of those events (fire) that upset plant stability and challenge critical safety functions. The finding was determined to be of low safety significance (Green) because the halon system was still operable to extinguish a fire in its incipient stage. (Section 1R05)

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance was identified by the inspectors involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control" requirements. The licensee had not updated the controlling calculation to assure that the motors would operate with undervoltage conditions after the high pressure coolant injection (HPCI) gland seal leak off (GSLO) turbine gland steam condenser exhauster and its hotwell drain pump motors were upgraded to safety-related equipment. After the inspectors identified these inconsistencies, the licensee revised the calculation, performed qualification testing, and generally fulfilled qualification that the motors would operate under the postulated undervoltage conditions.

This finding was more than minor because the design process allowed upgrading the motors to safety-related without assuring fulfillment of known design requirements that affected the mitigating system cornerstone objective of ensuring the availability, the reliability, and the capability of HPCI to respond to initiating events to prevent undesirable consequences. Continuous operation of the GSLO system was required to support HPCI operation because of room temperature concerns. The finding was determined to be of low safety significance (Green) because it did not represent an actual loss of the safety function. (Section 4OA5).

- Green. The inspectors identified a finding involving a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, for the failure of mechanical maintenance personnel to generate a condition report or inform a supervisor after identifying loose bolts on the standby liquid control relief valve. This human performance deficiency resulted in the licensee having to perform a historical operability evaluation on the condition of the system. In addition to the historical operability evaluation, the mechanical maintenance manager reinforced the requirement of initiating condition reports when deficiencies are identified.

  The finding was more than minor because it affected the mitigating system cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be of low safety significance (Green) because the system was determined to have been operable with the loose bolts. (Section 4OA5)

Cornerstone: Barrier Integrity

- Green. A self-revealing finding involving a Non-Cited Violation of Technical Specification 3.4.4 was identified for the licensee's failure to ensure that Unit 3 was not operated with reactor coolant pressure boundary leakage. As a result of this human performance deficiency, the licensee was not in compliance with Technical Specifications on two occasions for Unit 3 while operating with pressure boundary leakage. Corrective actions by the licensee included using an enhanced fit-up process to minimize the welding induced residual stresses and using proper tie-back support alignment to minimize mechanically induced stress. Also, the licensee established an exclusion zone and action level values to minimize reactor recirculation pump speed in the area of the resonance frequency of the piping. In addition, the licensee will install a piping configuration modification to improve the vibration response characteristics of both "A" and "B" reactor recirculation loops high and low pressure sensing lines.

  The finding was considered more than minor because the issue affected the barrier integrity cornerstone. This finding was evaluated using Phase 1 of the significance determination process (SDP) which screened Phase 2 because the finding affected the reactor coolant system barrier. The inspectors determined that this finding was of very low safety significance (Green) because additional equipment not credited in the Probabilistic Risk Assessment was available to mitigate the leak and the contribution of this type of event to the baseline core damage frequency was small. (Section 4OA3)

B. Licensee Identified Findings

Violations of very low safety significance, which were identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at full power. On July 20, 2003, operators reduced load to 630 MWe to perform rod pattern adjustments and reverse circulating water flow through the condenser. The unit was returned to full power the same day. On August 10, 2003, operators reduced load to 793 MWe to swap rods. The unit was returned to full power the same day. On August 24, 2003, operators reduced load to 850 MWe to perform control valve testing, and the unit was returned to full power the same day. On September 7, 2003, operators reduced load to 660 MWe to perform rod pattern adjustments and perform testing on the isolation condenser system. The unit was returned to full power the same day. On September 28, 2003, the operators reduced load to 650 Mwe to perform work on the 2A reactor feed pump and the 2A condensate/condensate booster pump. Prior to completing this work the unit scrammed on September 30, 2003, due to low reactor water level after the 2C reactor feed pump tripped due to a ground fault.

Unit 3 began the inspection period at full power. On August 16, 2003, operators reduced the load to 700 MWe to perform rod swaps, and the unit was returned to full power on August 17, 2003. On September 27, 2003, operators reduced load to 416 MWe for deep/shallow rod adjustments, and installation of a castle nut on 3B reactor feed pump casing. The unit returned to full power on September 29, 2003.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity and Emergency Preparedness

1R01 Adverse Weather (71111.01)

a. Inspection Scope

The inspectors performed an assessment of the licensee's implementation of the station's winter readiness process.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments (71111.04)

.1 Partial Walkdowns

a. Inspection Scope

The inspectors selected a redundant or backup system to an out-of-service or degraded train, reviewed documents to determine correct system lineup, and verified critical portions of the system configuration. Instrumentation valve configurations and appropriate meter indications were also observed. The inspectors observed various support system parameters to determine the operational status. Control room switch positions for the systems were observed. Other conditions, such as adequacy of housekeeping, the absence of ignition sources, and proper labeling were also evaluated.

The inspectors performed three partial walkdowns of the following systems:

- Unit 2 High Pressure Coolant Injection;
- Unit 2B Core Spray; and
- Unit 2 Isolation Condenser.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors toured six plant areas important to safety to assess the material condition, operating lineup, and operational effectiveness of the fire protection system and features. The review included control of transient combustibles and ignition sources, fire suppression systems, manual fire fighting equipment and capability, passive fire protection features, including fire doors, and compensatory measures. The following areas were walked down:

- Unit 2 Reactor Building, Elevation 476'-6" East Low Pressure Coolant Injection Corner Room (Fire Zone 11.2.2);
- Unit 2 Reactor Building, Elevation 589' Standby Liquid Control Area (Fire Zone 1.1.2.5.D);
- Unit 3 Reactor Building, Elevation 589' Isolation Condenser Area (Fire Zone 1.1.1.5.A);
- Unit 2 Reactor Building, Elevation 476'-6" High Pressure Coolant Injection Room (Fire Zone 11.2.3);
- Unit 3 Reactor Building, Elevation 476'-6" High Pressure Coolant Injection Room (Fire Zone 11.1.3); and
- Unit 2 Reactor Building, Elevation 517'-0" (Fire Zone 1.1.2.2).

b. Findings

.1 Inadvertent Initiation of the Halon System in the Auxiliary Electric Equipment Room

Introduction: A Green self-revealed finding involving a Non-Cited Violation of Technical Specifications was identified for the failure of an instrument maintenance supervisor to obtain permission from the fire marshal prior to performing hot work. This human performance deficiency resulted in the automatic initiation of the halon system in the Unit 2/3 auxiliary electric equipment room.

Description: On July 22, 2003, instrument maintenance personnel were performing Work Order #573460-04 to remove a defective and obsolete seismic recorder located in the floor of the Unit 2/3 auxiliary electric equipment room. After the recorder was removed, the next step, instructional Step 2, was to assist the mechanical maintenance personnel in removing the concrete expansion anchors. The instrument maintenance supervisor misinterpreted instructional step 2 to mean that the instrument maintenance personnel could perform the grinding to remove the anchors. Therefore, an instrument technician proceeded with the grinding activity, and debris in the air from the grinding caused the fire alarm system, XL-3, to alarm and automatic initiation of the halon system. Administrative procedure OP-AA-201-004, "Fire Prevention for Hot Work," Revision 5, Step 5.1.1, requires the work supervisor to obtain permission from the fire marshal to perform hot work operations by completing Section 1 of the Hot Work Permit, Attachment 1. Section 1 identified the hot work to be performed, the extinguisher location, the need to have a fire watch ½ hour after the hot work completed, any special precautions to be implemented, and the fire marshal's signature approving the performance of the work. Since the instrument maintenance supervisor had not obtained permission from the fire marshal to perform the hot work, the grinding by the instrument technician was a violation of OP-AA-201-004.

Analysis: The inspectors determined that the maintenance supervisor's failure to follow procedure OP-AA-201-004 was a performance deficiency warranting a significance evaluation. The inspectors reviewed this finding against the guidance contained in Appendix B, "Issue Disposition Screening," of Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports." The inspectors determined that the finding was more than minor because it affected the initiating events cornerstone objective to limit the likelihood of those events (fire) that upset plant stability and challenge critical safety functions. The finding also affected the cross-cutting area of Human Performance because the maintenance supervisor failed to obtain permission from the fire marshal prior to conducting the grinding activity.

In reviewing the finding using the Manual Chapter 0609, "Significance Determination Process," Phase 1, the inspectors determined that the finding did not contribute to the likelihood of a loss of coolant accident, did not contribute to the likelihood of a reactor trip and the likelihood of the unavailability of mitigation equipment or functions, and did not increase the likelihood of a fire. The issue was determined to be of low safety significance (Green) because the halon system was still operable to extinguish a fire in its incipient stage.

Enforcement: Dresden Technical Specification 5.4.1 states that procedures shall be established, implemented, and maintained covering the fire protection program. Procedure Step 5.1.1 of OP-AA-201-004, Revision 5, requires the work supervisor to obtain permission from the fire marshal to perform hot work by completing Section 1 of the Hot Work Permit, Attachment 1.

Contrary to the above, on July 22, 2003, the instrument maintenance supervisor did not obtain permission from the fire marshal prior to grinding in the auxiliary electric equipment room. Corrective actions by the licensee included establishing a continuous fire watch, refilling all halon bottles, briefing of this event with all instrument maintenance personnel, and coaching of individuals in accordance with station policy. Because this issue is of very low safety significance and has been entered into the licensee's corrective action program as Condition Report No. 168648, this violation is being treated as an NCV, consistent with Section VI. A, of the NRC Enforcement Policy. NCV 05000237/2003-007-01 and 05000249/2003-007-01.

1R06 Flood Protection (71111.06)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report flood analysis documents and reviewed the licensee's procedures for internal and external flooding. The inspectors walked down the Unit 2 and 3 containment cooling service water system pump vault rooms and low pressure coolant injection systems corner rooms to verify drainage was unobstructed and to verify the integrity of flood barriers. In addition, the inspectors reviewed licensee procedures for external flooding for ensuring proper safe shutdown of the plant, and reviewed the licensee's previously implemented corrective actions for deficiencies associated with flood protection.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Quarterly Review of Licenced Operator Qualifications

a. Inspection Scope

On September 29, 2003, the inspectors observed operating crew #6 during an "out-of-the-box" requalification examination on the simulator. The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- ability to take timely actions;
- prioritization, interpretation and verification of alarms;
- procedure use;
- control board manipulations;
- supervisor's command and control;
- management oversight; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following documents:

- OP-AA-101-111, "Roles and Responsibilities of On-Shift Personnel," Revision 0;
- OP-AA-103-102, "Watchstanding Practices," Revision 2;
- OP-AA-103-103, "Operation of Plant Equipment," Revision 0;
- OP-AA-103-104, "Reactivity Management Controls," Revision 2; and
- OP-AA-104-101, "Communications," Revision 1.

The inspectors verified that the crew completed the critical tasks listed in the above simulator guide. The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed the licensee evaluators to verify that they also noted the issues and discussed them in the critique at the end of the session.

The inspectors also reviewed selected issues documented in CRs, to determine if they had been properly addressed in the licensee's corrective actions program. The documents reviewed during this inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of Job Performance Measure (JPM) operating tests and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from June 16 through July 25, 2003. The overall results were compared with the significance determination process in accordance with NRC Manual Chapter 0609I, "Operator Requalification Human Performance Significance Determination Process (SDP)."

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee's overall maintenance effectiveness for risk-significant mitigating systems. The inspectors also reviewed whether the licensee properly implemented the Maintenance Rule, 10 CFR 50.65, for the systems. Specifically, the inspectors determined whether:

- the system was scoped in accordance with 10 CFR 50.65;
- performance problems constituted maintenance rule functional failures;
- the system had been assigned the proper safety significance classification;
- the system was properly classified as (a)(1) or (a)(2); and
- the goals and corrective actions for the system were appropriate.

The above aspects were evaluated using the maintenance rule program. The inspectors also verified that the licensee was appropriately tracking reliability and/or unavailability for the systems.

The inspectors reviewed the following system:

- Unit 2 and 3 reactor protection system.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

a. Inspection Scope

The inspectors evaluated the effectiveness of the risk assessments performed before maintenance activities were conducted on structures, systems, and components and verified how the licensee managed the risk. The inspectors evaluated whether the licensee had taken the necessary steps to plan and control emergent work activities.

The inspectors completed evaluations of four maintenance activities:

- Unit 3A Recirculation Pump Deviation Meter Replacement in Panel 903-4;
- Unit 2 Containment Cooling Service Water Keep Fill Check Valve Replacement;
- Unit 2 Core Spray System Testing; and
- Unit 2/3 emergency diesel generator seismic qualification utility group modification and the 2-0263-153A reactor wide range pressure "A" signal isolator replacement.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance Related to Non-routine Evolutions and Events (71111.14)

a. Inspection Scope

The inspectors reviewed the licensee's response to any potential impacts on plant operations from the eastern power outage that occurred on August 14, 2003. The inspectors reviewed control room indication traces from the date of the power outage and interviewed licensed operators on any perturbations. In addition, the inspectors verified that the licensee did not plan on performing any production risk activities and that there were no surveillances that were approaching their respective critical due dates. Also, the inspectors evaluated the licensee's response to a Unit 2 scram on September 30, 2003, which occurred on low reactor water level due to the tripping of the 2C reactor feed pump. The inspectors will review the licensee event report on this issue during the next inspection report period.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following four operability evaluations:

- Unit 2 and Unit 3 Isolation Condenser Actuation Time Delay Impact from Electromatic Relief Valve Setpoint Change (Operability Evaluation No. 03-008);
- Unit 2 and 3 Steam Dryer, Revision 0 and 1 (Operability Evaluation No. 03-009);
- More Industries SCI Signal Converter/Isolator (Operability Evaluation No. 03-005); and
- 3A Standby Liquid Control Relief Valve Bolting Torque Found Out of Specification (CR# 162781).

The inspectors reviewed the technical adequacy of the evaluations against the Technical Specifications, UFSAR, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with the requirements of LS-AA-105, "Operability Determination Process," Revision 1.

In addition, the inspectors reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modification (71111.17)

a. Inspection Scope

The inspectors reviewed one permanent plant modification to verify the design adequacy to ensure licensing bases and design bases were maintained, and to ensure functionality of interfacing structures, systems, and components. The modification reviewed was the following:

- Installation on new 138kV feed to Dresden Unit 2 138kV reserve auxiliary transformer 22 (RAT22).

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed post-maintenance test results to confirm that the tests were adequate for the scope of the maintenance completed and that the test data met the acceptance criteria. The inspectors also reviewed the tests to determine if the systems were restored to the operational readiness status consistent with the design and licensing basis documents.

The inspectors reviewed ten post-maintenance testing activities involving risk significant equipment in the mitigating systems cornerstone:

- Replaced Unit 2 high pressure coolant injection room cooler fan bearings;
- Repair the Unit 2/3 fire damper between the auxiliary electric equipment room and cable tunnel;
- Relanded lead for relay 2-1530-273 for low pressure coolant injection logic-reactor recirculation pumps running;
- Replaced drywell vent valve 2-1601-23;
- Replaced lock washer on plunger assembly for head cooler isolation valve 2-0205-24;
- Replaced Unit 3 standby liquid control flow indicating controller FIC 3-1158;
- Replaced leaking 2A containment cooling service water pump discharge check valve 2-1501-1A;
- Replaced Unit 2 core spray valves 2-1412-500 and 501;
- Replaced Unit 2 high voltage power supply for source range monitor 21; and
- Replaced 2D main steam line low pressure switch, 2-0261-30D.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed surveillance testing on risk-significant equipment and reviewed test results. The inspectors assessed whether the selected plant equipment could perform its intended safety function and satisfy the requirements contained in Technical Specifications. Following the completion of each test, the inspectors determined that the test equipment was removed and the equipment returned to a condition in which it could perform its intended safety function.

The review included the following five surveillance testing activities:

- DIS 2300-08, Unit 2 Contaminated Condensate Storage Tank Level Switches Functional Test and Unit 2 Torus Level Switches Functional Test, Revision 20;
- DIS 1500-13, Low Pressure Coolant Injection System Discharge Header Flow Master Trip Unit Channel Functional Test, Revision 12;

- DOS 0500-25; Reactor Protection System, Channels A1, A2, B1 and B2 Automatic Scram Contactor Test, Revision 7;
- DIS 1700-21, Reactor Building Ventilation Channel A and Channel B Area Radiation Monitor Channel Calibration Test, Revision 9; and
- DIS 1600-16, Drywell Hi Rad Monitor Functional Test, Revision 13.

b. Findings

No findings of significance were identified.

1R23 Temporary Modification (71111.23)

a. Inspection Scope

The inspectors screened active temporary modifications on systems ranked high in risk and assessed the effect of the temporary modifications on safety-related systems. The inspectors also determined if the installations were consistent with system design. The inspectors reviewed the following temporary modification:

- Temporary Modification No. 3444460, "Adjust Deadband for High Pressure Coolant Injection High Level Switches LS 3-0263-25A3 (B3)."

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed station personnel during the licensee's 3rd quarter performance indicator emergency preparedness drill on September 10, 2003, to determine the effectiveness of drill participants and the adequacy of the licensee's critique in properly determining the emergency classification and identifying weaknesses and failures. The scenario included an earthquake, fire in the Unit 2/3 cribhouse, and a loss of the Unit 2 reserve transformer and all emergency core cooling system bus AC power for greater than 15 minutes.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

.1 Walkdowns of Liquid and Gaseous Effluent Monitoring and Control Systems

a. Inspection Scope

The inspectors performed walkdowns of selected components of the liquid and gaseous effluent monitoring and processing systems, including point of discharge effluent and process radiation monitors and the liquid radioactive waste "Tank Farm," to verify that the current system configuration was as described in the Updated Final Safety Analysis Report (UFSAR) and was consistent with the Offsite Dose Calculation Manual (ODCM), and to assess equipment material condition. The inspectors also walked down the Radioactive waste (radwaste) system control panel in the radwaste control room and discussed processing equipment reliability, use, and operating practices with radwaste staff.

b. Findings

No findings of significance were identified.

.2 Radioactive Effluent Release Data, Dose Calculations, and ODCM Changes

a. Inspection Scope

The inspectors reviewed the 2001 and 2002 Radioactive Effluent Release Reports, the errata report for the 2000 effluent report, and selected radioactive effluent release data for January 2002 through March 2003. The reports and data were reviewed to verify that the radioactive effluent control program was implemented as described in the ODCM, to verify that Technical Specification and ODCM dose limits were not exceeded, and to ensure that any anomalies in the reports and effluent release data were adequately understood by the licensee and were properly assessed and reported. The inspectors reviewed the licensee's current methodology for the calculation of offsite dose, and selectively reviewed results of liquid and gaseous effluent sample analyses for selected periods in 2002 through early 2003, to verify that the licensee calculated dose from effluents consistent with the ODCM. In particular, the inspectors reviewed effluent data and associated dose calculation reports for all the unmonitored/abnormal releases (Dresden Abnormal Releases (DAR)) included in the 2001 and 2002 effluent reports to assess the licensee's ability to adequately determine the public dose impact from those releases. The inspectors also reviewed revisions made to the ODCM in calendar years 2001 and 2002, and the justifications for other than editorial changes to the ODCM, to verify they did not adversely impact effluent controls and were evaluated by the licensee and reported in accordance with requirements.

b. Findings

No findings of significance were identified.

.3 Liquid and Gaseous Effluent Releases

a. Inspection Scope

The inspectors selectively reviewed batch liquid effluent release data and continuous gaseous effluent release data (for the time period January 2002 through February 2003), including results of station chemistry sample analyses and vendor laboratory analysis results for difficult to measure nuclides, and the licensee's release procedures, practices and dose projections to members of the public. The review was performed to verify that the licensee adequately applied analysis results and that dose calculations conformed to ODCM methodology and Technical Specification requirements. The inspectors also selectively reviewed grab sample radioisotopic analysis results and licensee alarm set point calculations for liquid effluent batch releases to verify that the data was properly used to complete calculations of offsite dose consistent with ODCM methodology and the licensee's procedures.

The inspectors accompanied a chemistry technician during a weekly change-out and analysis of the particulate filter, iodine cartridge and noble gas sampling for the Dresden 2/3 Chimney, to verify that sampling and handling practices, and analytical techniques were technically sound and consistent with procedures.

b. Findings

No findings of significance were identified.

.4 Liquid and Gaseous Effluent Monitor Calibration

a. Inspection Scope

The inspectors reviewed the current instrument calibration records for selected point-of-discharge and process effluent radiation and flow rate monitors, to determine if they had been calibrated consistent with industry standards and in accordance with station procedures and the ODCM. Specifically, the inspectors reviewed channel calibration records for the following effluent radiation detectors and flow monitors:

- Dresden 2/3 Chimney System Particulate, Iodine and Noble Gas (SPING);
- Dresden 2/3 General Electric (back up) Chimney Monitors;
- Dresden 2/3 Reactor Building Vent SPING;
- Dresden 1 Chimney SPING;
- Dresden 2/3 Radwaste River Effluent Monitor;
- Dresden 3 Service Water Monitor; and
- Dresden 2 and 3 Isolation Condenser Vent Area Radiation Monitors.

The inspectors also assessed monitor set point methodology and alarm set point values for these monitors, to verify the technical viability of the calibration program and for compliance with ODCM criteria. Additionally, the inspectors reviewed effluent and process radiation monitoring availability and system health information for 2002 and 2003, and discussed monitor performance and reliability with system engineering staff.

b. Findings

No findings of significance were identified.

.5 Air Cleaning System Surveillance Tests

a. Inspection Scope

______The inspectors reviewed the most recent results of the Ventilation Filter Testing Program for the Standby Gas Treatment and Control Room Emergency Ventilation Systems to verify that test methodology, frequency and test results met Technical Specification requirements. Specifically, the inspectors reviewed and discussed with the system engineering staff the test results of in-place high efficiency particulate air (HEPA) and charcoal absorber penetration tests, laboratory tests of charcoal absorber methyl iodide penetration, in-place combined HEPA filter and charcoal absorber train pressure drop tests.

b. Findings

No findings of significance were identified.

.6 Analytical Instrumentation Quality Control and Inter-Laboratory Comparison Program

a. Inspection Scope

______The inspectors reviewed chemistry department quality control data for selected instrumentation systems used to quantify effluent releases. Specifically, the inspectors reviewed the most recent efficiency calibration records and lower limit of detection (LLD) determinations for all spectroscopy systems used to analyze effluent samples. The review was performed to determine if calibration and efficiency acceptance criteria and ODCM specified LLDs were met and if the calibrations were conducted consistent with industry standards.

The inspectors reviewed the results of selected quarterly 2002 and 2003 radiochemistry inter-laboratory cross checks for both the licensee and its vendor analytical laboratory, to determine if the cross check program was being implemented adequately and to verify the quality of the radioactive effluent analyses performed by the licensee and its contract laboratory.

b. Findings

No findings of significance were identified.

.7 Identification and Resolution of Problems

a. Inspection Scope

______The inspectors reviewed the results of a 2003 focus area self-assessment of the radioactive effluent monitoring and control program and ODCM implementation, Nuclear Oversight Department field observation reports completed in 2003, and condition reports (CRs) generated during approximately the 18 month period preceding the inspection that related to ODCM implementation and the liquid and gaseous effluent monitoring and control program. The documents were reviewed to evaluate the licensee's ability to assess the radiological effluent monitoring and control program, to assess the scope and adequacy of the licensee's problem identification program and its ability to identify repetitive problems or trends, contributing causes and extent of condition, and to implement corrective actions intended to achieve lasting results.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator (PI) Verification (71151)

.1 Initiating Events and Mitigating Systems

a. Inspection Scope

The inspectors sampled the licensees submittals for performance indicators (PIs) and periods listed below. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline" to verify the accuracy of the PI data. The following four PIs were reviewed:

Unit 2

- safety system function failures, July 2002 through June 2003, and
- high pressure coolant injection system, October 2002 through August 2003.

Unit 3

- safety system function failures, July 2002 through June 2003, and
- high pressure coolant injection system, October 2002 through August 2003.

The inspectors reviewed selected applicable conditions and data from logs, licensee reports and CRs. The inspectors independently re-performed calculations where applicable. The inspectors compared that information to the information required for each performance indicator definition in the guideline to ensure that the licensee reported the data accurately.

b. Findings

No findings of significance were identified.

.2 Radiological Effluent Technical Specification (RETS)/ODCM Radiological Effluent Occurrence PI

a. Inspection Scope

The inspectors reviewed the licensee's assessment of its two public radiation safety performance indicator for RETS/ODCM radiological effluent occurrences to determine if the indicator was adequately assessed and reported consistent with industry guidelines as provided by the applicable revision of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." Specifically, the inspectors reviewed CRs generated during the 12 months preceding the inspection to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. Also, the inspectors evaluated the licensee's methods for determining offsite dose and selectively verified that liquid and gaseous effluent release data and associated offsite dose calculations performed since this indicator was last reviewed in June 2002 were accurate. Records of monthly PI data elements were reviewed for June 2002 through March 2003 to verify that data was recorded and verified as required by the licensee's procedure.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspector selected Condition Report (CR) No. 175749 for detailed review. The CR was associated with the repeated surveillance failures of the containment cooling service water (CCSW) system vault penetrations. The report was reviewed to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated the report against the requirements of the licensee's corrective action program as delineated in the corporate administrative procedure LS-AA-125, "Corrective Action Program (CAP) Procedure," Revisions 4 and 5, and 10 CFR 50, Appendix B.

b. Findings

The inspector identified that a significant number of CRs had been written with regard to CCSW vault penetration seal failures. The inspector performed a walkdown of flood protection features associated with the Unit 2 and Unit 3 CCSW pump vaults. The pump vaults contain safety related mitigating systems susceptible to flooding from station internal equipment sources. There are four pumps in each unit's CCSW system that are designed to provide cooling water to the containment cooling heat exchangers, required for a safe shutdown following a design basis accident or transient.

Two of the four pumps associated with each unit are contained within a watertight vault. The vaults are designed to ensure that a postulated rupture in the containment cooling service water system will not result in a loss of all four pumps from subsequent flooding. During the system walkdown, the inspector verified that there were no visible holes or unsealed penetrations in floors and walls, and that watertight doors between flood areas were maintained in good material condition. The inspector examined the licensee's penetration seal documentation for the purposes of determining if problems identified were entered into their corrective action program and if the problems were properly resolved. The nine penetrations were tested in accordance with Dresden Technical Surveillance (DTS) 0030-01, CCSW Pump Vault Surveillance Testing. A significant number of failures of Unit 2 and Unit 3 CCSW pump vault penetration seals had occurred between 1975 and 1996. The licensee's current corrective action process began in 1996. The inspector examined licensee's penetration surveillance records from 1997 to 2003 specifically for penetration seal failures.

The Technical Requirements Manual (TRM), Section 3.7.0, required that an 18-month surveillance be performed on the nine CCSW vault penetration seals with an acceptance criterion that there was no visible leak detection solution (soap bubble solution) on the pressure-free side of the penetration when subjected to 15 psig on the pressurized-side of the penetration. Upon failure of any of the nine penetration seals, the Control Room was notified and the CCSW pump vault was declared inoperable and this in turn resulted in the B and C CCSW pumps, which are located inside the pump vault, being declared inoperable per TRM action statement 3.7.o.C.1. Based on the inoperability of the two CCSW Pumps, the respective operating unit entered a 7-day action statement per Technical Specification 3.7.1 to restore at least one pump to operable status. In addition, the unit entered an 8-hour action statement per the TRM 3.6.a, for inoperability of the Drywell Spray subsystem.

The licensee has a history of numerous penetration failures that required maintenance personnel to tighten the penetration belt link seals and bring the seals into conformance with the acceptance criteria of the surveillance requirements. This tightening of failed seals has repeatedly been required every 18 months on both units since March 28, 1997. The result of the repetitive seal failures (based on each unit having 9 penetration seals tested) is detailed below.

> Unit 3: 3/28/97- 6 failures; 1/29/99- 4 failures; 12/11/01- 3 failures; 6/06/02- 2 failures.
>
> Unit 2: 3/06/98- 5 failures; 10/11/99- 6 failures; 4/12/01- 3 failures; 5/01/02- 4 failures.

In summary, there were eight tests involving 33 failed penetration seals over a period exceeding 5 years; however, the licensee did not quantify the leakage rate during the 5-year period. By not quantifying the leakage rate the licensee could not establish or assure the reliability of the penetration seals in order to prevent all four pumps from being inoperable during the internal flooding event. The repetitive failure of the penetration seals is indicative of an established acceptance criterion that cannot be relied upon to maintain the seal integrity through the entire surveillance interval.

On July 30, 2002, the licensee shortened the surveillance test interval to every 3 months instead of 18 months based on the continued failures. The results from the 3-month test interval is detailed below.

> Unit 2: 7/30/02- 1 failure; 10/29/02- 2 failures; 1/30/03- 3 failures; 4/30/03- 3 failures.
>
> Unit 3: 9/04/02- 3 failures; 12/03/02- 1 failure; 3/05/03- 4 failures.

On June 27, 2003, the licensee determined that the existing acceptance criterion of zero-leakage was over-conservative. The licensee subsequently changed the criterion from no visible seal leakage, to less than or equal to a total leakage of 1.5 gpm for all nine wall penetrations, the floor drain check valve, and the vault bulkhead door. The appropriate acceptance criterion change was made to TRM Section TSR 3.7.0.2.

The leakage surveillance tests, after the criterion was changed to include a measurable value, resulted in the following recorded data:

> Unit 3: 6/27/03 - Total Leakage .3015 gpm, results well within acceptance criterion of 1.5 gpm
>
> Unit 2: 7/29/03 - Total Leakage .2312 gpm, results well within acceptance criteria of 1.5 gpm
>
> Unit 3: 9/03/03 - Total Leakage .4475 gpm, results well within acceptance criteria of 1.5 gpm

The licensee plans to review, as part of its correction actions detailed in CR No. 175749, all failed surveillances over the past 5 years to identify and correct any similar occurrences.

4OA3 Event Follow-up (71153)

.1 (Closed) LERs 2002-003-00,"Reactor Recirculation Loop A Sensing Line Socket Weld Vibration Fatigue Failure," and

(Closed) LER 2002-006-00: Reactor Recirculation Loop A Sensing Line Socket Weld Failure

Introduction: A Green self-revealed finding involving a Non-Cited Violation of Technical Specifications was identified on October 8, 2002, and December 7, 2002, for the licensee's failure to ensure that Unit 3 was not operated with reactor coolant pressure boundary leakage. As a result, the licensee was not in compliance with Technical Specifications on two occasions for Unit 3 while operating with pressure boundary leakage.

Description: On October 8, 2002, in preparation for shutting down Unit 3 for the start of the 17th refueling outage, the licensee entered the drywell to inspect for leakage due to an increasing trend in the reactor coolant system (RCS) leakage which had been trending up since September 14, 2002. The licensee identified that the leakage was from a 1 inch diameter piping socket weld on the 'A' reactor recirculation loop low pressure flow venturi differential pressure sensing line. Technical Specification 3.4.4, "Reactor Coolant System Operational Leakage," requires that reactor coolant system operational leakage shall be limited to no pressure boundary leakage. As a result of the identified pressure boundary leakage, the licensee initiated the actions of Limiting Conditions for Operations 3.4.4.C to be in Mode 3 in 12 hours and Mode 4 in 36 hours.

The licensee performed a root cause investigation for the weld failure and determined that high cycle fatigue due to an inadequate 1-1 axial leg socket weld application in a system experiencing flow-induced vibration caused the failure of the weld. The weld was an industry standard at the time of its installation in 1985. The licensee replaced the sensing line elbows and piping with a pipe configuration without elbows. Also, as part of the repair, the licensee performed the weld installation with a 2-1 axial leg socket weld on the 3A and 3B reactor recirculation sensing lines. The licensee's failure to implement effective corrective actions from two previous high cycle fatigue weld failures on similar configurations and to implement recommendations from the Electrical Power Research Institute report TR-113890 to build up the weld to a 2-1 axial weld contributed to this repeat weld failure.

Due to the return of elevated drywell leakage on November 8, 2002, the licensee reduced power to perform a drywell inspection on December 7, 2002. The licensee identified that a Unit 3 weld failure occurred on the reactor recirculation "A" loop low pressure flow venturi differential pressure sensing line. The licensee's completed root cause investigation concluded that the weld failure was due to mechanically induced residual pipe stress caused by the inadequate installation techniques performed on the reactor recirculation sensing line repaired during the last refueling outage in October 2002 (same weld as above), along with sensing line vibration caused by resonance frequency with the pump speed.

To repair this failure, the licensee used an enhanced fit-up process to minimize the welding induced residual stresses and used proper tie-back support alignment to minimize mechanically induced stress. Also, the licensee established an exclusion zone and action level values to minimize reactor recirculation pump speed in the area of the resonance frequency of the piping. In addition, the licensee plans to install a piping configuration modification to improve the vibration response characteristics of both "A" and "B" reactor recirculation loops high and low pressure sensing lines.

Analysis: The inspectors evaluated this finding using Phase 1 of the SDP which screened this finding to a Phase 2 because the finding affected the RCS barrier. The inspectors used the risk-informed inspection notebook for Dresden Nuclear Power Station, Units 2 and 3, Revision 1, dated May 3, 2002, to complete the Phase 2 evaluation. In reviewing the Phase 2 assessment performed by the resident inspectors, the senior reactor analyst (SRA) identified that the dominant sequence SLOCA - EC in the Dresden SDP Worksheet was potentially risk significant. Further review by the SRA identified that this sequence was an overly conservative sequence. The EC represents vapor suppression of the containment and SLOCA represents a small break loss of coolant accident. The worksheet only credited successful operation of 12 out of 12 vacuum breakers to perform the EC function; however, this was a passive action to ensure the vacuum breakers were closed or remain closed. In reviewing the licensee's Probabilistic Risk Analysis (PRA), the SRA noted that the licensee defines success of vapor suppression as either 12 out of 12 vacuum breakers, containment spray or reactor pressure vessel (RPV) blowdown. The SDP worksheets did not provide additional credit for containment sprays or RPV blowdown. If additional credit was provided for containment sprays (1 multi-train) in the EC function, the full point value for the sequence would be 8 multi-train. This would result in the sequence being of very low risk significance. Additionally, the licensee's PRA identified the SLOCA contribution to overall CDF of <1%, with a baseline CDF of 1.9E-08/reactor-year. This results in an overall SLOCA contribution from all sources of small breaks as <2.0 E-08/reactor-year. As a result of the vacuum breaker function of EC being a passive action, NRR has removed this sequence from recently benchmarked plants, as it was not found to be a dominant contributor to SLOCA. Therefore, the finding was determined to be of very low safety significance, Green. The inspectors determined that this finding also affected the cross-cutting area of Human Performance because the licensee operated Unit 3 in non-compliance of Technical Specifications on two occasions.

Enforcement: Technical Specification 3.4.4, "Reactor Coolant System Operational Leakage," requires that reactor coolant system operational leakage shall be limited to no pressure boundary leakage in Modes 1, 2, and 3. The Limiting Condition for Operation Action Statement requires that the plant be placed in Mode 3 in 12 hours and Mode 4 in the following 36 hours. Although the exact time that the pressure boundary leakage occurred could not be precisely determined, it is clear that the leakage existed for greater than the 12 and 36 hour time limits to place the plant in Mode 3 and 4, respectively. Therefore, the licensee failed to operate Unit 3 in accordance with Technical Specification 3.4.4 which resulted in operating the unit in Modes 1, 2 and 3, with pressure boundary leakage from September 14 through October 8, 2002, and November 8 through December 7, 2002. This failure is of very low safety significance and has been entered into the licensee's corrective action program as condition reports 126277 and 134459. Therefore, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. NCV 050000249/2003-07-02.

.2 (Closed) LER 50-237;249/2003-001-00: "Electromatic Relief Valve (ERV) Pressure Switches Drift Greater Than Estimated." This issue was closed as a licensee identified violation under Section 4OA7 of this inspection report.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R05 of this report had, as its primary cause, a human performance deficiency, in that an instrument maintenance supervisor failed to obtain permission from the fire marshal prior to a instrument technician performing grinding in the auxiliary electric equipment room. As a result, the fire marshal did not approve the hot work, a fire watch was not established, and an automatic initiation of the halon system occurred.

.2 A finding described in Section 4OA3 of this report had, as its primary cause, a human performance deficiency, in that the licensee operated Unit 3 on two occasions with pressure boundary leakage. As a result, the licensee was not in compliance with Technical Specifications 3.4.4.

.3 A finding described in Section 4OA5 of this report had, as its primary cause, a human performance deficiency, in that maintenance personnel failed to generate a condition report upon identifying loose bolts on the relief valve for the standby liquid control system. As a result, the licensee had to prepare a historical operability evaluation to determine if the system was operable.

.4 A finding described in Section 4OA5 of this report had, as its primary cause, a human performance deficiency, in that the licensee staff, despite previous identification that changing the motors to safety related would require a revised calculation supporting motor operation at reduced voltage, failed to verify that the motors would operate with the undervoltage conditions of the controlling calculation.

4OA5 Other Activities

.1 (Closed) Unresolved Item 50-237/249/2000-003-03(DRS): Failure to Re-analyze the Operation of the High Pressure Coolant Injection (HPCI) gland seal leak off (GSLO) System at Below the Minimum Required Operating Voltage When the System was Upgraded to Safety-Related Status

a. Inspection Scope

The inspectors assessed an URI regarding the licensee's failure to re-analyze the operation of the HPCI GSLO turbine gland steam condenser exhauster and its hotwell drain pump motors below the minimum required operating voltage of 90 percent of rated voltage. The re-analysis was needed to ensure that minimal operating voltages were available for these components since these components were upgraded to safety-related status in 1997 and 1998 for Units 3 and 2, respectively.

The licensee reexamined the acceptability of the available voltage for the exhauster and hotwell drain pump motors and documented the results in calculation DRE96-0189, "Voltage on Loads Fed from the Safety-Related 250 VDC Batteries," Revision 01. The NRC reviewed the calculation. The NRC reviewed the results of licensee conducted qualification tests of similar motors and agreed that the motors remained operable under the postulated undervoltage conditions.

b. Findings

Introduction: The inspectors determined that the design control process failed to translate design criteria into procedures creating a condition where the acceptability of the HPCI GLSO turbine gland steam condenser exhauster and its hotwell drain pump motors had not been verified by a valid calculation or qualification test when the motors were upgraded to safety-related status. This issue was considered to be of very low safety significance and was dispositioned as an NCV.

Description: When the inspectors reviewed the existing calculation at the time that the motors were upgraded to safety-related status, the inspectors noted several inconsistencies. The conclusion section of this calculation stated that the HPCI turbine gland steam condenser exhaust and its hotwell drain pump motors would experience less than 90 percent of their rated voltage during one or more periods. Therefore, successful operation of the equipment could not be assured. The calculation also documented that the subject equipment was classified as non safety-related and would not be required for HPCI operation. Furthermore, the conclusion section stated that if these motors were upgraded to safety-related in the future, additional investigation would be required to demonstrate successful operation at available voltages. The inspectors identified that although the motors had been re-classified as safety-related, and needed for HPCI operation, the licensee had not performed requisite analysis to ensure equipment operability. After the inspectors identified these inconsistencies, the licensee revised the calculation, performed qualification testing and generally, fulfilled qualification that the motors would operate under the postulated undervoltage conditions.

Analysis: Using Manual Chapter 0612, Appendix B, “Issue Disposition Screening,” the inspectors determined this finding was more than minor because the design process allowed upgrading the motors to safety-related without assuring fulfillment of known design requirements that affected the mitigating system cornerstone objective of ensuring the availability, and the reliability and capability of HPCI to respond to initiating events to prevent undesirable consequences. Continuous operation of the GSLO system was required to support HPCI operation because of room temperature concerns. The inspectors used Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” regarding mitigating systems and determined that the finding did not represent an actual loss of the safety function. Therefore, the finding screened as Green, a finding of very low safety significance. This finding was assigned to the mitigating systems cornerstone for both units.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures be established to assure that applicable regulatory requirements and design basis are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to the above, as of February 9, 2000, the design requirement to assure that the HPCI GLSO turbine gland steam condenser exhauster and its hotwell drain pump motors would operate at less than 90 percent of their rated voltage during one or more periods was not correctly translated into specifications, drawings, procedures or instructions for the subject motors. Specifically the controlling calculation had not been updated to assure that the motors would operate with the undervoltage conditions when the motors were upgraded to safety-related. Because the licensee entered the condition into their corrective action system as Corrective Action Process PIF D2000-00801, “Calculation DRE96-0189 Does Not Reflect SR Upgrade of HPCI GSLO & GDEF,” this violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 050000237/2003-007-03 and NCV 050000249/2003-007-03.

.2 (Closed) Unresolved Item 50-237;249/2002-006-03: Halon and CO_2 Fixed Suppression System Functionality Issues. This issue was reviewed by the Office of Nuclear Regulation (NRR) and the Office of General Counsel (OGC). The NRC staff's acceptance of the CO_2 system was based on the licensee's commitment to satisfy the requirements of National Fire Protection Association (NFPA) 12-1973, "Carbon Dioxide Extinguishing Systems." The NRC staff's acceptance of the Halon System was based on the licensee's commitment to satisfy the requirements of NFPA 12A-1973, "Halogenated Fire Extinguishing Agent Systems - Halon 1301." The licensee's design basis for the auxiliary equipment and electric room CO_2 system was 50 percent concentration with soak time of 10 minutes. The design basis for the Halon system was 5 percent with soak time of 10 minutes. The review conducted by NRR and OGC determined that the design concentration and soak time for both systems were acceptable.

Although the licensee committed to design and install a CO_2 system which met the requirements of NFPA 12-1973, the licensee specifically took exception to the NFPA 12 requirements for testing and stated that installation acceptance tests were not specifically performed. Licensee records stated that shop testing was completed for the systems. In the NRC's Safety Evaluation Report which accepted the system as adequate based on the commitment to NFPA 12-1973, no concerns were identified with the exception to testing. None of the requirements of 10 CFR 50.48, General Design Criteria 3, and the criteria of Branch Technical Position 9.5-1 specifically required a full discharge test to be conducted to prove operability. Additionally, the 1973 edition of the standard for both systems did not explicitly require a full discharge test. Therefore, no full discharge test was required. The NRC concluded that the licensing basis for gaseous suppression systems at Dresden has been met. This item is closed.

.3 (Closed) Unresolved Item 50-237/03-006-04: Loose Bolts on the Unit 3 "A" Standby Liquid Control System Relief Valve

Introduction: The inspectors identified a finding involving a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, for the failure of mechanical maintenance personnel to generate a condition report after identifying loose bolts on the standby liquid control relief valve. This human performance deficiency resulted in the licensee having to perform a historical operability evaluation on the condition of the system.

Description: As a result of the inspectors' review of licensee-identified measuring and test equipment concerns, the inspector reviewed work order 00420336-07. The work order directed the replacement of the Unit 3 "A" standby liquid control relief valve which used torque wrench #0013622580. Prior to starting the work on October 12, 2002, the maintenance mechanics documented that the "A" relief valve bolts were found finger tight instead of at their required torque value. Subsequently, the inspector identified that a condition report had not been written for the nonconforming condition nor was an operability evaluation performed on the system. Administrative Procedure, LS-AA-125, "Corrective Action Program (CAP) Procedure," Revision 4, requires that Exelon Nuclear personnel and contractors at Exelon Nuclear locations shall originate a condition report or inform a supervisor when an undesirable condition is recognized. The mechanical maintenance personnel's failure to generate a condition report upon finding the loose bolts on the standby liquid control system is a violation.

After identified by the inspector, both the maintenance and engineering department personnel wrote condition reports and determined a historical operability evaluation was warranted. The maintenance condition report assumed the finger tight bolts were on the discharge flange and not the inlet; however, the condition report written by engineering personnel was to evaluate the system operability for both the inlet and discharge flanges. In addition to the historical operability evaluation, the mechanical maintenance manager reinforced the requirement of initiating condition reports when deficiencies are identified. The inspectors reviewed the licensee's historical operability evaluation and concluded that the system remained operable because quarterly surveillance testing flow requirements were met and no leakage was identified from the inlet side of the relief valve. With respect to the outlet flange, the standby liquid control pressure at the relief valve during an anticipated transient without scram was evaluated to reach 1469 psig. The relief valve was tested in November 2002 and indicated a correct lift pressure of 1500 psig. Therefore, if the system had been required to operate, the relief valve would not have lifted and the outlet flange bolts would not have been pressurized.

Analysis: The finding was more than minor because it affected the mitigating system cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors' review of this finding using the significance determination process, Phase 1, determined that the finding screened out as Green because the finding was not a design deficiency, was not an actual loss of safety function, was not a loss of safety function beyond the allowed outage time of technical specifications, was not a loss of safety function of one or more non-technical specification trains of risk significant equipment, and was not complicated by any external events. This finding was determined to be of low safety significance because the system was determined to have been operable with the loose bolts. The inspectors determined that this error also affected the cross-cutting area of Human Performance because the maintenance personnel failed to generate a condition report for the as-found deficient condition.

Enforcement: Appendix B, Criterion V, 10 CFR 50, requires that activities affecting quality shall be accomplished in accordance with procedures. Administrative Procedure, LS-AA-125, "Corrective Action Program (CAP) Procedure," Revision 4, requires that Exelon Nuclear personnel and contractors at Exelon Nuclear locations shall originate a condition report or inform a supervisor when an undesirable condition is recognized. Contrary to the above, on October 12, 2002, maintenance mechanics working on the "A' standby liquid control system relief valve did not generate a condition report nor inform a supervisor upon the discovery of the loose bolts on the relief valve as required by LS-AA-125. This is a violation of 10 CFR 50, Appendix B, Criterion V. Because this violation is of very low safety significance and has been entered in to the licensee's corrective action program as condition reports 162781and 162835, this violation is being treated as an NCV, consistent with Section VI.A, of the NRC Enforcement Policy: NCV 05000249/2003-007-04.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. R. Hovey and other members of the licensee's staff on October 9, 2003. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

- Licensee-identified Non-Cited Violation with Mr. D. Bost, on September 8, 2003, via telephone. A letter containing the enforcement action was issued on October 8, 2003.
- Interim exit was conducted with Mr. J. Hansen on September 16, 2003, via telephone, for the Green finding on an Unresolved Item concerning Design Control of support pumps that were upgraded to safety related for the HPCI system.
- Interim exit was conducted for Licensed Operator Requalification 71111.11B with Mr. B. Surges on August 4, 2003, via telephone.
- Public Radiation Safety effluent monitoring and control program inspection with Mr. D. Bost on July 11, 2003.

4OA7 Licensee Identified Violation

The following violation of very low significance was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as NCVs.

Cornerstone: Barrier Integrity

.1 10 CFR 50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

10 CFR 50.9 requires, in part, that information required by the Commission's regulations, orders, or license conditions to be maintained by the licensee shall be complete and accurate in all material respects.

Commonwealth Edison Nuclear Station Welding Procedure NSWP-W-01, "ASME Welding," Revision 5, dated June 12, 1998, required, in part, that Quality Verification perform pre fit-up and fit up inspections.

Exelon Nuclear Procedure NO-AA-300-001, "Inspection Planning and Execution of Quality Inspection Activities," Revision 0, dated September 10, 2001, applied to independent inspection for safety related, ASME code, and augmented quality work at Exelon nuclear stations. Section 5 of the procedure required, in part, that inspections be documented using approved instructions, procedures, process sheets, travelers, or checklists and applicable drawings.

As described in AR 00127520 and 00128073, on October 15, 2002, a contract Quality Verification (QV) inspector failed to perform pre fit-up and fit-up inspections associated with four welds on the flow sensing line of the Unit 3A recirculation loop. Additionally, the QV inspector documented on the ASME Weld Record that the inspections had been completed. This information is material to the NRC because it demonstrates compliance with the Commission's regulations and procedures of the Dresden Nuclear Power Station.

The NRC Office of Investigation (OI) investigated the matter and concluded that the individual deliberately falsified quality control records. Since the incident was determined to be a deliberate violation of NRC requirements, the violation was subject to the traditional enforcement process instead of the NRC's significance determination process. The violation was categorized in accordance with the NRC's Enforcement Policy at Severity Level IV. On October 8, 2003, after considering the circumstances of the case and after consulting with the Director, Office of Enforcement, a Non-Cited Violation was issued to the licensee (ADAMS Accession No. ML032820115), consistent with Section VI.A.1 of the NRC's Enforcement Policy.

.2 <u>(Closed) LER 50-237/249/2003-001-00</u>: "Electromatic Relief Valve (ERV) Pressure Switches Drift Greater than Estimated"

On May 19, 2003, while performing DIS 0250-03, Revision 37, "Electromatic Relief Valve/Target Rock Valve Pressure Switches Calibration," on Unit 3, instrument maintenance department personnel found that the pressure switch setpoint (with head correction) for ERV 3-203-3B (as-found at 1112.6 psig) exceeded the Technical Specification (TS) allowable value of ≤1110.5 psig, and the analytical limit of 1112 psig. Additionally, the pressure switch setpoint for ERV 3-203-3D (as-found at 1134.5 psig) exceeded the TS allowable value of ≤1133.5 psig. The licensee readjusted each pressure switch to within procedural tolerances and declared each switch operable prior to proceeding to the next switch.

On May 21, 2003, while performing DIS 0250-03, Revision 37, on Unit 2, instrument maintenance department personnel found that the pressure switch setpoint (with head correction) for ERV 2-203-3B (as-found at 1113.6 psig) exceeded the TS allowable value of ≤1110.5 psig, and the AL of 1112 psig. Additionally the pressure switch setpoint for ERV 2-203-3C (as-found at 1112.9 psig) exceeded the TS allowable value of ≤1110.5 psig and the analytical limit of 1112 psig. The licensee readjusted each pressure switch to within procedural tolerances and declared each switch operable prior to proceeding to the next switch.

TS 3.3.6.3 requires that the relief valve instrumentation for each function in Table 3.3.6.3-1 shall be operable with an allowable value of ≤1133.5 psig for relief valves and ≤1110.5 psig for the low set relief valves. Contrary to the above, on May 19, 2003, ERV 3-203-3B and ERV 3-203-3D as-found pressure switch setpoints exceeded the TS allowable values, and on May 21, 2003, ERV 2-203-3B and ERV 2-203-3C as-found pressure switch setpoints exceeded the TS allowable values.

The licensee conducted a root cause evaluation and determined that the root cause of this event were ineffective implementation of previous corrective actions (lower the field setpoints) from three 1996 LERs and calculation errors (underestimation of the expected setpoint drift). A missed opportunity was identified in that a previous root cause evaluation for a similar event in 2002 (LER 50-237/2002-005) did not identify all of the root causes.

The safety significance of this event was minimal because the design functions for the relief valves would not have been compromised and reactor pressure would have remained within the safety analyses while taking into account the actual as-found setpoint values.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
D. Bost, Plant Manager
H. Bush, Acting Radiation Protection Manager
R. Conklin, Radiation Protection Supervisor
G. Dorsey, Chemistry Manager
R. Gadbois, Shift Operations Superintendent
V. Gengler, Dresden Site Security Director
J. Griffin, Regulatory Assurance - NRC Coordinator
J. Hansen, Regulatory Assurance Manager
J. Henry, Operations Director
R. Hovey, Site Vice President
C. Kolotka, Acting Chemistry Manager
T. Loch, Supervisor, Design Engineering
D. Nestle, Health Physicist/Acting ODCM Coordinator
M. Overstreet, Radiation Protection Supervisor
R. Quick, Security Manager
R. Rybak, Acting Regulatory Assurance Manager
F. Sadnick, Project Manager, Wackenhut Corporate
A. Shahkarami, Engineering Director
J. Sipek, Nuclear Oversight Director
N. Spooner, Site Maintenance Rule Coordinator
B. Surges, Operations Requalification Training Supervisor
B. Svaleson, Maintenance Director
S. Taylor, Radiation Protection Director

Nuclear Regulatory Commission
M. Ring, Chief, Division of Reactor Projects, Branch 1

IEMA
R. Schulz, Illinois Emergency Management Agency
R. Zuffa, Resident Inspector Section Head, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000237/2003007-01 05000249/2003007-01	NCV	Failure to Meet Technical Specification 5.4.1, Fire Protection Program Implementation for Hot Work Activities
05000249/2003007-02	NCV	Failure to Operate Unit 3 without Pressure Boundary Leakage as Required by Technical Specification 3.4.4
05000237/2003007-03 05000249/2003007-03	NCV	Failure to Re-analyze to Assure Operation of the HPCI Gland Seal Leak Off (GSLO) System at Undervoltage Conditions When the System Was Upgraded to Safety-Related Status
05000249/2003007-04	NCV	Failure of Mechanical Maintenance Personnel to Generate a Condition Report after Identifying Loose Bolts on the Standby Liquid Control Relief Valve

Closed

05000237/2003007-01 05000249/2003007-01	NCV	Failure to Meet Technical Specification 5.4.1, Fire Protection Program Implementation for Hot Work Activities
05000249/2003007-02	NCV	Failure to Operate Unit 3 without Pressure Boundary Leakage as Required by Technical Specification 3.4.4
05000237/2003007-03 05000249/2003007-03	NCV	Failure to Re-analyze to Assure Operation of the HPCI Gland Seal Leak Off (GSLO) System at Undervoltage Conditions When the System Was Upgraded to Safety-Related Status
05000249/2003007-04	NCV	Failure of Mechanical Maintenance Personnel to Generate a Condition Report of Inform a Supervisor after Identifying Loose Bolts on the Standby Liquid Control Relief Valve
50-237/2000-003-03 50-249/2000-003-03	URI	Failure to Re-analyze the Operation of the HPCI Gland Seal Leak off (GSLO) System at Below the Minimum Required Operating Voltages When the System Was Upgraded to Safety-Related Status
50-237/2002-006-03 50-249/2002-006-03	URI	Halon and CO_2 Fixed Suppression System Functionality Issues
50-237/03-006-04	URI	Loose Bolts on the Unit 3 “A” Standby Liquid Control System Relief Valve

50-237/2003-001-00 50-249/2003-001-00	LER	Electromatic Relief Valve (ERV) Pressure Switches Drift Greater Than Estimated
50-249/2002-003-00	LER	Reactor Recirculation Loop A Sensing Line Socket Weld Vibration Fatigue Failure
50-249/2002-006-00	LER	Reactor Recirculation Loop A Sensing Line Socket Weld Failure

Discussed

None.

LIST OF ACRONYMS USED

ALARA	As-Low-As-Is-Reasonably-Achievable
AR	Action Request
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCSW	Containment Cooling Service Water
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
DC	Direct Current
DIS	Dresden Instrument Surveillance
DOS	Dresden Operating Surveillance
DOT	Department of Transportation
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EC	Engineering Change
ERV	Electromatic Relief Valve
FSAR	Final Safety Analysis Report
GSLO	Gland Seal Leak Off
HPCI	High Pressure Core Injection
IEMA	Illinois Emergency Management Agency
IMC	Inspection Manual Chapter
JPM	Job Performance Measure
kV	kiloVolts
LHRA	Locked High Radiation Area
MWe	megawatts electrical
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSWP	Nuclear Station Welding Procedure
OA	Other Activities
OE	Operability Evaluation
OGC	NRC Office of General Counsel
OI	NRC Office of Investigations
PI	Performance Indicator
PRA	Probabilistic Risk Analysis
QV	Quality Verification
RCS	Reactor Coolant System
RP	Radiation Protection
RPV	Reactor Pressure Vessel
SDP	Significance Determination Process
SR	Safety-Related
SRA	Senior Reactor Analyst
UFSAR	Updated Final Safety Analysis Report
USAR	Updated Safety Analysis Report

URI	Unresolved Item
VHRA	Very High Radiation Area
WO	Work Order

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.

1R01 Adverse Weather Protection

CR 176588; Nuclear oversight identifies winter readiness ineffective corrective action; September 19, 2003

OP-AA-108-109, "Seasonal Readiness," Revision 1

DOS 0010-19, "Preparation for Cold Weather for Unit 1 and Out Buildings," Revision 15

DOS 0010-22, "U2 Preparations for Cold Weather," Revision 11

DOS 0010-25, "U3 Preparations for Cold Weather," Revision 11

CR 172915; Winter readiness preparations; dated August 25, 2003

CR 125536; Nuclear oversight identifies winter readiness deficiencies; dated October 2, 2002

CR 138104; Winter readiness preventative maintenance appears to be scheduled late in the season; dated January 4, 2003

CR 169966; Improper winter readiness for reactor building chillers; dated August 1, 2003

CR 143193; Winter readiness; dated February 6, 2003

Winter Readiness Critique for 2003

1R04 Equipment Alignment

CR 173762; Oil on basement wall, 2/3A isolation condition make up sump inoperable; August 29, 2003

CR 165636; Unit 2 250Vdc battery foam spacers; dated June 30, 2003

Drawing M-51, Diagram of H.P. Coolant Injection Piping

Unit 2 DOP 2300-M1/E1, Unit 2 HPCI System

DOP 1400-M1,"Unit 2 Core Spray System," Revision 20

DOP 1400-E1,"Core Spray Electrical," Revision 03

DOP 1300-M1/E1, "Isolation Condenser System," Revision 13

1R05 Fire Protection

CR 176243; Safe shutdown emergency light #201 battery needs to be replaced; dated September 17, 2003

CR 174991; Safe shutdown light 311A inoperable; September 9, 2003

CR 174422; Leaking pipe; September 5, 2003

CR 174152; Penetration F-49-10 as found with 4" ceramic blanket; September 3, 2003

CR 173975; Incorrect penetration fire barrier shown on drawing; August 27, 2003

CR 173929; Penetration F-79-16 found with 6" ceramic fire blanket; August 28, 2003

CR 171458; Penetration F-71-01(B) found with 2" of ceramic fire blanket; August 13, 2003

CR 172929; Turbine building fire main has through-wall leak; August 25, 2003

CR 168655; System actuation precludes continuous auxiliary electrical equipment room fire watch; dated July 23, 2003

CR 168852; Safe shutdown light found unacceptable condition; dated July 24, 2003

CR 169149; Safe shutdown light #362 fast charge light on continuously; dated July 25, 2003

CR 169169; Safe shutdown light #360 has fast charge light on and low electrolyte; dated July 26, 2003

CR 166358; Operations shift less than minimum manning for fire brigade; dated July 5, 2003

Dresden Fire Protection Report Volume 1, "Updated Fire Hazards Analysis"

Fire Pre-Plan U2RB-3, Revision 5

Fire Pre-Plan U2RB-11, Revision 5

Fire Pre-Plan U3RB-31, Revision 5

Fire Pre-Plan U2RB-4, Revision 5

Fire Pre-Plan U3RB-22, Revision 5

Fire Pre-Plan U2RB-5, Revision 5

1R06 Flood Protection

CR 176191; Containment cooling service water vault watertight door predefine has incorrect frequency; September 17, 2003

UFSAR 3.4 Water Level (Flood) Design, Revision 4

Technical Requirements Manual (TRM) 3.7, Plant Systems, Revision 0

Drawing Number FL-1, Flood Barriers Basement Floor, May 26, 1995

Drawing Number FL-11, Section FL-11 Flood Barrier Turbine Building, May 26, 1995

Drawing Number FL-12, Section FL-12 Flood Barriers Turbine Building, May 26, 1995

FASA No. 142203-03, Focused Area Self-Assessment - Flooding, March 3, 2003

CR 175998; NRC identifies issues with sub doors to Torus basement; dated September 16, 2003

CR 149463; Containment coolant service water vault drain line check valve is not tested; dated March 14, 2003

CR 149463; Focus area self-assessment flooding; dated March 17, 2003

CR 158435; Extended power uprate impact on sizing of emergency flood pump not evaluated; dated May 12, 2003

WO 99270171; D2 18M TS Containment coolant service water vault drain valve test; March 18, 2003

WO 348236; D3 18M TS Containment coolant service water vault drain valve test; March 25, 2003

DOS 4400-01, Containment Cooling Service Water Vault Floor Drain, Revision 7

DOA 0010-04, Floods, Revision 15

DOS 4400-01, Containment Cooling Service Water Vault Floor Drain, Revision 7

1R11 Operator Requalification

CR 172209; Operator license renewal letter not received by the NRC; dated August 18, 2003

CR 172128; Crew evaluation paperwork lost; dated August 11, 2003

CR 170322; Licensed Operator Requalification Training CRC meeting evaluation receives low rating on scorecard; dated August 5, 2003

CR 167198; Non-compliance with TQ-AA-106-0305, Licensed Operator Requalification Training exam administration job aid; dated July 11, 2003

CR 167285; Near miss on crew aligned during annual dynamic evaluation; dated July 11, 2003

CR 168349; Operations Team 5 crew clock resets due to annual exam failures; dated July 21, 2003

CR 169450; Conflicting information identified in Licensed Operator Requalification Training job performance measure for standby gas treatment system; dated July 29, 2003

CR 169501; Operation Team 4 crew clock resets due to annual exam failures; dated July 29, 2003

1R12 Maintenance Effectiveness

CR 166038; CR 161288 determined a maintenance rule functional failure; dated July 2, 2003

CR 165838; Unit 3 fuel reliability indicator (FRI) exceed 300; dated July 1, 2003

1R13 Maintenance Risk Assessments and Emergent Work Control

CR 167854; Unit 2 containment cooling service water system standby pressure low; dated July 16, 2003

CR 167588; Containment cooling service water abnormal noise; dated July 15, 2003

CR 168648; Halon injection during work in auxiliary electric; dated July 22, 2003

CR 168826; Area for improvement for operation fire brigade response to the Auxiliary electrical equipment room; dated July 23, 2003

W.O. 00594058-01; Troubleshooting Recirculation Pump 3A Speed Oscillations

EC 343813; Provide Engineering Acceptance of the Installation of a Temporary Deviation Meter for Recirculation Pump 3A

Procedure CC-AA-112; “Temporary Configuration Changes,” Revision 5

1R15 Operability Evaluations

CR 171812; Dryer Operability Determination; dated August 8, 2003

CR 166927; Monthly PMs changed to quarterly on execution day; dated July 9, 2003

CR 168363; Unit 2 and Unit 3 steam dryer potential design nonconformance; dated July 21, 2003

CR 165823; Isolation condenser actuation time delay impact from electromatic relief setpoint change; dated July 1, 2003

UFSAR Section 5.4.6; Isolation Condenser

Technical Specification 3.3.5.2; Isolation Condenser System Instrumentation

Technical Specification 3.5.3; Isolation Condenser System

Calculation NED-I-EIC-0093; Electromatic Relief Valve/Target Rock Valve Pressure Switch Error Analysis; dated 5/30/03

1R17 Permanent Plant Modification

EC Number EC340723; Installation on New 138kV Feed to Dresden Unit 2 138kV Reserve Auxiliary Transformer 22 (RAT22); Revision 01

LS-AA-104-1001; 50.59 Review Coversheet Form; Revision 1

LS-AA-104-1001; 50.59 Evaluation Form; Revision 2

Affected Documents List for EC340723; dated August 16, 2003

Drawing 12E-913; Schematic Diagram of 345kV Switchyard Annunciator; Revision K

Drawing 12E-3954 thru 3957; Wiring Diagram of 345kV Switchyard Control Panel; Revision S

Drawing 12E-6652J; Schematic Diagram TR86 Control & Indication; Revision K

1R19 Post Maintenance Testing

W.O. 00590605; DIS 0250-02, Revision 18; “Main Steam Line Low Pressure Isolation Switch Calibration (Reactor Mode Switch in Run Position)”

W.O. 00459355; Replaced PS 2-2361-30D

W. O. 00481977; Instrument Maintenance Replace HV P/S for SRM 21; June 20, 2003

DIS 0700-10; Data Sheet 1, “SRM Channel 21 Rod Block Calibration”; dated September 24, 2003

DOS 1400-07, Revision 15, “Emergency Core Cooling System Venting”

W.O. 374465-03; Core spray valve replacement, 2-1412-500 and 501

CR 171338; Wrong solenoid ordered for 2-1601-23; dated August 13, 2003

W.O. 00584370; DOS 1600-03, “Unit 2 Quarterly Valve Timing,” Revision 29

W.O. 00545980; Replace leaking 2A containment cooling service water pump discharge check valve 2-1501-1A

W.O. 00483398-01; Metering Valve Leaking Air

DIS 1100-06, Revision 4, “Preventative Maintenance and Functional Check of Standby Liquid Control Flow Indicating Controller FIC 2(3)-1158"

W.O. 00613958; “Replace Leaking 2A Containment Cooling Service Water Pump Discharge Check Valve 2-1501-1A

DOS 1500-02, Revision 48, “Containment Cooling Service Water Pump Test and Inservice Test (IST)”

W.O. 00594620; High Pressure Coolant Injection Room Cooler Vibrating and Making Excessive Noise - Replace Cooler Fan Bearings, dated July 11, 2003

CR 167124; High pressure coolant injection room cooler fan high vibrations; dated July 10, 2003

Procedure DMP 5700-04; “Low pressure coolant injection and high pressure coolant injection Room Cooler Maintenance”; Revision 9

W.O. 00599404; Repair electro thermal link for damper 2/3-9472-011

DEP 2100-06,”Crimping and Termination of Low Voltage Small Insulated Lugs and Connectors,” Revision 4

DFPS 4175-09,”Fire Damper Visual Inspection,” Revision 10

DOS 1600-03,”Unit 2 Quarterly Valve Timing,” Revision 29

DOS 40-7,”Verification of Remote Position Indicator for Valve Included In Inservice Testing (IST) Program

DOS 1600-28,” Air Operated Valve Fail Safe and Accumulator Integrity Test,” Revision 9

1R22 Surveillance Test

CR 176605; Unit 3 emergency diesel generator cooling water supply found out of tolerance; September 19, 2003

Technical Specifications 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

Technical Specifications 3.3.6.1 Primary Containment Isolation Instrumentation

CR 175541; Unit 2 isolation condenser heat capacity test data results; dated September 12, 2003

CR 174806; main steam line high flow DPIS 3-0261-2P; AF value exceeded TS value; dated September 9, 2003

CR 174805; main steam line high flow DPIS 3-0261-2M found high greater than TS limit; dated September 8, 2003

CR 173669; As found data not transferred to as left data block; dated July 14, 2003

CR 173405; 2-1530-273 did not respond in accordance with DIS 1500-35; dated August 27, 2003

CR 173159; 2/3 Post Accident Radiation Monitor Detectors Not Fully Inserted; dated August 26, 2003

CR 170488; Out of tolerance during DIS 1600-03; Torus to reactor building differential pressure calibration; dated August 6, 2003

CR 170366; 3-263-62 Reactor vessel core differential pressure transmitter; dated August 5, 2003

CR 170036; Out of tolerance during DIS 1300-02; dated August 1, 2003

CR 169994; Potential to not meet Technical Specification Surveillance; dated July 31, 2003

CR 167158; DIS 2400-01; dated July 10, 2003

CR 167918; 2B post-loss of cooling accident H2/O2 - 02 cell found out of tolerance; dated July 17, 2003

CR 168218; Hydraulic control unit 38-59 pressure switch found out of tolerance during DIS 300-02; dated July 18, 2003

CR 168400; Found 2-8540-5 & 2-8540-6 our of tolerance, no technical specification violation; dated July 21, 2003

CR 169099; Unit 2 high radiation sampling system heating, ventilation and air conditioning surveillance failed; dated July 25, 2003

CR 169217; Dirty contacts on scram resetting relay; dated July 27, 2003

CR 169413; Hydraulic control unit pressure switches - adverse trend on out of tolerance; dated July 23, 2003

CR 168493; 3-0263-52B found out of tolerance; dated July 22, 2003

CR 166127; DPIS 2-1350-A and 2-1350-B found out of tolerance; dated July 3, 2003

WO 00580443; D2 Quarterly Tech Spec Reactor Building Ventilation Radiation Monitor Call and Functional; August 21, 2003

Work Request 99-111852 Revision 1; D2 18M/RFL Tech Spec Drywell Hi Rad Monitor Functional Calibration; November 3, 2001

Work Request 99-212795 Revision 1; D2 24/RFL Tech Spec Drywell Hi Rad Monitor Functional Calibration; October 23, 2002

Improved Technical Specification Table 3.3.6.1-1; Primary Containment Isolation Instrumentation

1R23 Temporary Modification

WO00610330—DIS 0263-07, Unit 2 ATWS RPT/ARI and ECCS Level Transmitters Channel Calibration Test and EQ Maintenance Inspection, Revision 12

71152 Problem and Identification Resolution

CR 176311; Tools, parts and clear plastic bags found on the reactor building crane; September 18, 2003

CR 176034; Issue unresolved for one year, lack of effective screening; dated August 27, 2003

CR 1751745; Quarterly review of reactor building containment cooling water ACE assigned Grade 3; dated September 15, 2003

CR 173178; High pressure coolant injection system Unit 2 motor gear unit - timeliness of corrective actions; August 26, 2003

CR 172485; 2003 INPO evaluation AFI - - SE.1-2; August 11, 2003

CR 172351; Nuclear oversight review of chemistry focus area self-assessment (FASA); dated July 2, 2003

CR 169094; Torus level increase; dated July 25, 2003

CR 169181; Containment requiring more frequent venting; dated July 23, 2003

CR 168824; Service water radiation monitor low flow alarm; dated July 23, 2003

CR 169845; Scaffold built without work order; dated July 31, 2003

71153 Event Follow-up

CR 178699; Unit 2 unplanned automatic and manual scrams exceeded goal; September 30, 2003

CR 178577; PPC point T076 did not detect a reactor scram signal; September 30, 2003

CR 178507; Reactor fuel pump trip caused reactor scram; September 30, 2003

CR 167124; High pressure coolant injection room cooler fan high vibrations; July 10, 2003

4OA1 Performance Indicator Verification

CR 118156; Safety system functional failure regulatory assurance performance indicator exceeds threshold; dated August 5, 2002

4OA5 Other Activities

PIF D2000-00801; Calculation DRE96-0189 Does Not Reflect SR Upgrade of HPCI GSLO & GDEF; February 9, 2000

Calculation DRE96-0189; Voltages on Loads Fed from the Safety-Related 250 VDC Batteries; Revision 1

Calculation DRE97-0161; Justification for Continued Operation Of HPCI Gland Seal Exhauster Subsystem Components; Revision 02

4OA7 Licensee-Identified Violations

AR 00128073; Identified adverse trend with QV inspections; dated October 19, 2002

AR 00127520; Human performance issue with QV inspection; dated October 15, 2002

AR 00134726; Socket weld fitting dimensions not per design; dated December 9, 2002

NSWP-W-01; ASME Welding; Revision 5

NO-AA-300-001; Inspection Planning and Execution of Quality Inspection Activities; Revision 0

WO 00542473-01

WO 00542479-01

CR 159815; Out of tolerance; dated May 21, 2003

CR 159816; Out of tolerance, dated May 21, 2003

CR 159552; DIS 0250-03 Emergency relief valve/target rock pressure switches out of tolerance; dated May 19, 2003