July 31, 2006

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

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3
NRC INTEGRATED INSPECTION REPORT 05000237/2006007;
05000249/2006007

Dear Mr. Crane:

On June 30, 2006, 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 July 18, 2006, with Mr. D. Wozniak and other members of your staff.

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

Based on the results of this inspection, four NRC-identified and two self-revealed findings of very low safety significance, five of which involved violations of NRC requirements were identified. However, because of the very low safety significance and because they were entered into your corrective action program, the NRC is treating these violations as non-cited violations (NCVs) consistent with Section VI.A.1. of the NRC Enforcement Policy.

If you contest these NCVs, 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, Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Dresden Nuclear Power Station.

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

Sincerely,

/RA/

Mark A. Ring, Chief
Branch 1
Division of Reactor Projects

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

Enclosure: Inspection Report 05000237/2006007; 05000249/2006007
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
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
Document Control Desk - Licensing
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer
Chairman, Illinois Commerce Commission

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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:	05000237/2006007; 05000249/2006007
Licensee:	Exelon Generation Company
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL 60450
Dates:	April 1 through June 30, 2006
Inspectors:	C. Phillips, Senior Resident Inspector D. Smith, Senior Resident Inspector M. Sheikh, Resident Inspector A. Barker, Project Engineer, Region III L. Ramadan, Reactor Engineer, Region III D. Melendez-Colon, Reactor Engineer, Region III N. Valos, Senior Operations Engineer (Lead Inspector), Region III C. Moore, Operations Engineer, Region III D. Jones, Reactor Engineer, Region III R. Schulz, Illinois Emergency Management Agency
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000237/2006007; 05000249/2006007; 04/01/2006 - 06/30/2006; Exelon Generation Company, Dresden Nuclear Power Station, Units 2 and 3; fire protection, maintenance effectiveness, maintenance risk assessments and emergent work control, personnel performance related to non-routine evolutions and events, and operability evaluations.

This report covers a 3-month period of baseline resident inspection and an announced baseline inspection in Licensed Operator Requalification Program. The inspection was conducted by Region III inspectors and the resident inspectors. Six Green findings, involving five non-cited violations, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

- Green. On May 1, 2006, the inspectors identified a non-cited violation of Unit 2 Operating License Condition E, Fire Protection Program, for failure to identify and correct a degraded fire barrier wall. The inspectors identified a wall gap in the Unit 2 emergency diesel generator day tank room. The gap was in a 3-hour fire rated wall, separating the Unit 2 diesel fuel oil day tank room from the Unit 2 reactor feed pump room. As corrective action, the licensee established a firewatch, entered the issue into the corrective action program, and repaired the gap in the wall.

  The finding was greater than minor because it affected the protection against external factors attribute of the Mitigating Systems cornerstone objective. However, the finding was of very low safety significance due to no credible fire scenarios developing that would have affected the safe shutdown of Unit 2, and due to the relatively negligible combustible loading in the area of the gap. The inspectors also concluded that this finding affected the cross-cutting issue of human performance (personnel). (Section 1R05)

- Green. On May 15, 2006, a finding involving a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, was identified by the inspectors. The licensee failed to identify a condition adverse to quality where the Unit 2 350 psig reactor low pressure emergency core cooling system (ECCS) permissive pressure switch was found outside the Technical Specification (TS) allowable tolerance range repeatedly. The licensee's actions lacked prioritization in determining the cause of the out-of-tolerance of the 2-0263-52B permissive pressure switch. Also, the licensee failed to assign timely corrective actions to evaluate the cause of the switch's repeated TS surveillance test failures.

The finding was greater than minor because it impacted the equipment performance attribute of the Mitigating System cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events. As corrective action, the licensee created action items to address the repeat failures of the 2-0263-52B switch to meet its TS requirements. The licensee wrote Issue Report (IR) 495327, "Trending IR for 2-0263-52B exceeds TS 6 of 9 Surveillances," to identify why this adverse trend was not entered into the corrective action system. As immediate corrective action, the licensee reduced the surveillance frequency to adequately monitor the switch's performance. The licensee also required all system managers and first line supervisors to review the station procedure for the instrument performance trending program, and implemented a manufacturer's recommendation to use smaller step changes in applied pressure to improve set point accuracy. The finding was of very low safety significance because the other permissive switch 2-0263-52A was always operable. Therefore, the switch's safety function and ability to permit reactor low pressure ECCS injection were maintained. The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution (corrective action). (Section 1R12)

- Green. A finding was self-revealed when an instrument maintenance technician shorted a power lead while performing modification work that resulted in the Unit 2 high pressure coolant injection system becoming inoperable for 2 hours and 14 minutes on April 6, 2006. No violation of NRC requirements was identified.

  This finding was more than minor because it involved the attribute of equipment performance of the Mitigating Systems objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance because the high pressure coolant injection system was inoperable for a short time period and could have been manually controlled in the event of an accident. The individual was counseled for a lack of attention to detail and the entire instrument maintenance department was made aware of this error. This finding affected the cross-cutting issue of human performance (personnel). (Section 1R14)

- Green. On May 5, 2006, the inspectors identified a finding involving a non-cited violation of 10 CFR 50.62 associated with a licensee-identified material condition, and having very low safety significance. The licensee identified that the inputs to a design analysis (DRE01-0066, "Dresden Unit 2 & 3 Standby Liquid Control System Discharge Piping Pressure Drop," Revision 1) were non-conservative. Some of the valves installed in the plant were not the same type of valves assumed to be installed in the design analysis. This ultimately resulted in a change in a design calculation that demonstrated that standby liquid control system relief valves could lift upon system initiation during an anticipated transient without scram (ATWS) event.

  The finding was more than minor because it affected the design control attribute of the Mitigating Systems objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences. The finding was of very low safety significance because the standby liquid control system could be recovered during an ATWS event. Cycling of the relief valves would not prevent most of the borated solution from being injected into the reactor pressure vessel, and the licensee was able to demonstrate that the reactor remained within the acceptance criteria of their original ATWS analysis even if no boron solution was injected into the reactor pressure vessel while the relief valves lifted. The licensee planned to use a more enriched form of boron so that one pump could be used to meet the 10 CFR 50.62 requirements. This enriched boron would replace the current boron in the storage tanks in the next refueling outages. This issue was a non-cited violation of 10 CFR 50.62. (Section 1R15)

Cornerstone: Barrier Integrity

- Green. On May 15, 2006, the inspectors identified a non-cited violation 10 CFR 50.65 (a) (4), having very low safety significance associated with inadequate management of risk. While working on the Unit 2 1601-20B reactor building to torus vacuum breaker relief valve, the Unit 2 risk status was designated as “yellow” and would have gone to “red” if the 2-1601-20A valve was also taken out-of-service. The 2-1601-20A vacuum relief valve was not clearly indicated as a protected pathway as required by station work control procedures and station personnel were not notified of the 2-1601-20B “yellow” risk status through any of the normal administrative methods.

  This finding was more than minor because this issue, if left uncorrected, could have become a more significant safety concern. Had the availability of the 2-1601-20A valve been affected, plant risk would have been elevated to a “red” condition. The plant risk model did not show that this equipment was required to have a protected pathway on the redundant equipment. In addition, during the extent of condition review, the licensee identified that six additional pieces of plant equipment should have indicated the requirement for protected pathways, but did not. The licensee corrected both these conditions. The inspectors evaluated this finding using IMC 0609, “Significance Determination Process,” and concluded the issue was of very low safety significance (Green) because no actual degradation of the barriers occurred. This finding affected the cross-cutting issue of human performance (resources). (Section 1R13)

- Green. On April 5, 2006, a performance deficiency involving a non-cited violation of TS 5.4.1 was self revealed when an auxiliary nuclear station operator (Aux NSO) and a unit supervisor (US) were performing Dresden Operating Procedure (DOP) 0500-03, “Reactor Protection System Power Supply Operation,” Revision 27. The Aux NSO and US did not verify that the area radiation monitor’s (ARM) power supply voltage was normal and did not reset all trips on the ARM modules prior to removing an installed jumper which bypassed the trips. This required entry into TS 3.6.4.1 Limiting Condition of Operation, Action A for reactor building low differential pressure. Both operators had been provided with marked up copies of the procedure, and briefed on jumper placement and removal and on the use of concurrent verification prior to the event.

  The finding was greater than minor because it impacted the structures, systems, and components attribute of the Barrier Integrity cornerstone objective. The finding was of very low safety significance because it impacted the reactor building differential pressure for a time period of less than 1 hour. As an immediate corrective action, the two individuals were temporarily removed from licensed shift duties. The operations department was tasked to develop a dynamic learning activity for place-keeping and jumper manipulation for all operations personnel, and to create an internal operating experience document to communicate lessons learned. This finding affected the cross-cutting area of human performance (personnel). (Section 1R14)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at 912 MWe (95 percent thermal power and 100 percent of rated electrical capacity).

- On May 27, 2006, power was reduced to 15 percent to perform a walkdown of the drywell to identify the source of a leak, to perform turbine valve testing, and to make a control rod pattern adjustment. The unit was returned to full power the next day.

- On June 8, 2006, power was reduced to 71 percent to replace the 2A feedwater regulating valve solenoid due to erratic operation. The unit was returned to full power the same day.

Unit 3 began the inspection period at 912 MWe (95 percent thermal power and 100 percent of rated electrical capacity).

- On June 4, 2006, power was reduced to 57 percent to perform turbine valve testing, control rod drive scram time testing, and to make a control rod pattern adjustment. The unit was returned to full power on the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope

The inspectors assessed the licensee's readiness for warm weather conditions during the time period of May 2006 and conducted inspections on the following equipment and systems:

- Unit 3 containment cooling service water vault;
- Unit 2 reactor building ventilation; and
- Unit 2 and 3 auxiliary electric equipment room heating, ventilation and air conditioning

The inspectors selected the above inspection samples to ensure the equipment could perform design functions during summer conditions. The inspectors reviewed the Updated Final Safety Analysis Report, the licensee's seasonal readiness procedure, previously initiated issue reports, and walked down equipment and systems to verify proper alignment in accordance with the licensee procedures to remove plant equipment and systems used for cold weather operations from service at the end of cold weather season.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope

The inspectors selected a redundant or backup system to an out-of-service or degraded train to determine that the system met the design of the Updated Final Safety Analysis Report. Piping and instrumentation diagrams were used to determine correct system lineup and critical portions of the system configuration were verified. Instrumentation, valve configurations, and appropriate meter indications were also observed. The inspectors observed various support system parameters to determine the operational status of systems. 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 partial equipment alignment walkdowns of the:

- Unit 3 emergency diesel generator ventilation system;
- Unit 2 emergency diesel generator;
- Unit 2/3 emergency diesel generator; and
- Unit 3 high pressure coolant injection system.

This represented four inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q and A)

.1 Routine Inspection

a. Inspection Scope

The inspectors toured plant areas important to safety to assess the material condition, operating lineup, and operational effectiveness of the fire protection system and features to ensure compliance with the station's Fire Hazard Analysis Report. 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 computer room and auxiliary electrical room, elevation 517' Fire Zone 6.2;
- Unit 2 low pressure coolant injection east corner room, elevation 476' Fire Zone 11.2.2;
- Unit 2 emergency diesel generator room, elevation 517' Fire Zone 9.0.A;
- Unit 3 emergency diesel generator room, elevation 517' Fire Zone 9.0.B;
- Unit 2 high pressure coolant injection room, elevation 476'-6" Fire Zone 11.2.3;
- Unit 2 low pressure coolant injection west corner room, elevation 476'-6" Fire Zone 11.2.1;
- Unit 2 station blackout diesel room, Fire Zone not applicable;
- Unit 2 reactor feed pump, elevation 517' Fire Zone 8.2.5A; and

- Unit 3 battery rooms, elevation 538' Fire Zone 6.1 and charger room, elevation 551' Fire Zone 7.0.B.

This represented nine inspection samples.

b. Findings

Failure to Identify an Inoperable 3-hour Fire Barrier Wall in the Unit 2 Emergency Diesel Generator (EDG) Day Tank Room

Introduction: The inspectors identified a non-cited violation (NCV) of Unit 2 Operating License Condition E, having very low safety significance (Green). The NCV was related to the licensee's failure to identify and correct a degraded 3-hour fire barrier wall in the Unit 2 EDG day tank room. This fire barrier separated the Unit 2 diesel fuel oil day tank room from the Unit 2 reactor feed pump (RFP) room.

Description: On May 1, 2006, while performing a fire protection walkdown of the Unit 2 EDG room, the inspectors identified a through-wall gap in the west corner of the diesel fuel oil day tank room. Light from the Unit 2 RFP room could be seen through the wall. The inspectors determined that a through-wall gap existed in a fire barrier wall and reported this condition to the licensee. The gap was promptly evaluated and was judged to be about 1/32 inch wide and about 5 feet long. The inspectors were informed that this fire barrier separated the Unit 2 diesel fuel oil day tank room, Fire Zone 9.0.A, from the Unit 2 RFP room, Fire Zone 8.2.5.A. Upon confirmation of the inspectors' concern, the licensee declared the carbon dioxide (CO^2) system for the Unit 2 EDG day tank room inoperable. The fuel oil day tank west wall was also considered to be inoperable as a 3-hour fire barrier.

The licensee immediately implemented the appropriate technical requirement manual limiting condition for operation actions by establishing an hourly fire watch, and entered the deficiency into the corrective action program as issue report IR 485432. The licensee's engineering evaluation stated that this gap is speculated to have formed when the wall was poured during original construction when a seal did not form between the concrete and the steel beam. Licensee personnel completed a permanent repair of the fire barrier wall gap per work order WO 917879.

The gap had not been identified by the licensee because the existing surveillance requirement was not properly performed. Station procedure DFPS 4175-02, "Operating Fire Stop/Break Surveillance," Revision 12, Section I.1.d, stated, in part, "besides the listed penetrations, the entire surface of the fire rated assembly shall be inspected for open penetrations or breaks of any kind." This surveillance was last completed for the Unit 2 emergency diesel fuel oil tank room wall on January 11, 2005. The inspectors interviewed the individual that performed the inspection, and the individual acknowledged that the entire surface of the barrier had not been inspected.

Analysis: The inoperable fire barrier wall represented a licensee performance deficiency because the gap in the 3-hour fire barrier wall would be expected to have been identified and corrected by the licensee using Fire Protection Surveillance (DFPS) Procedure 4175-2, "Operating Fire Stop/Break Surveillance," Revision 12. The affect of the identified deficiency was that since original construction a communication path existed between the two fire zones. The requirement to have fire barriers was to ensure that a postulated fire would not propagate to more than one fire area, thus jeopardizing the availability of safe shutdown equipment. Using Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," dated September 30, 2005, the finding was greater than minor because it affected the protection against external factors attribute of the Mitigating Systems cornerstone objective.

The inspectors evaluated the finding using IMC 0609, Appendix F, "Fire Protection Significance Determination Process (SDP)," dated February 28, 2005, Attachment 2, Table A2.1, and concluded that the finding affected the defense-in-depth element of fire barrier degradation in the fire confinement category. Based on the gap being about 1/32 inch wide and 5 feet long through a 3-hour barrier wall, the degradation level was categorized as low "Green."

Factors which contributed to this classification included the following: a credible fire scenario could not be developed that would have affected the safe shutdown of Unit 2 because both zones were in the same fire area. The Unit 2 EDG oil day tank room had a negligible amount of combustibles. The fuel oil was excluded from the combustible loading because it was located within an National Fire Protection Association qualified tank and which is assumed not to rupture. The inspectors considered in their evaluation the lack of electrical cables in the area of the gap, the fact that the Unit 2 fuel oil day tank room is protected by both an automatic CO^2 suppression and an automatic wet pipe sprinkler system, the relatively small transient combustible loading in the area of the gap from the Unit 2 RFP side, and the fact that the Unit 2 RFP area is protected by an automatic wet pipe sprinkler system.

The inspectors also concluded that this finding affected the cross-cutting issue of human performance (personnel) because the licensee failed to accomplish activities in accordance with prescribed instructions in a station procedure. Specifically, a surveillance test was performed on this wall in January 2005 and the gap was not found because the entire surface of the wall was not inspected in accordance with station procedure DFPS 4175-02.

Enforcement: Operating License Condition No DPR-19, Section E, requires that the licensee shall implement and maintain in effect all provisions of the approved Fire Protection Program, as described in the Updated Final Safety Analysis Report (UFSAR).

The UFSAR, Section 9.5.1, "Fire Protection System," states, in part, that the design bases and system descriptions are described in the Dresden Fire Protection Report (DFPR), Volume 1, "Updated Fire Hazards Analysis."

The DFPR, Section 2.3.1.2, "Barriers," states, in part, that walls enclosing separate fire areas utilize fire resistive construction. All penetrations in a fire resistive barrier are protected so that they have an equivalent fire resistance rating or are evaluated to ensure their adequacy to withstand the hazards associated with the areas.

Drawing F-10-1, Revision F, located in the DFPR, Volume 1, "Updated Fire Hazards Analysis," describes the west wall of the Unit 2 EDG day tank room as a 3 hour fire barrier.

The UFSAR Section 13.5.3.3, “Fire Protection Surveillance” (DFPS), also states, in part, that fire protection surveillances provide for verification of operability or performance characteristics of systems/equipment.

Fire protection surveillance procedure DFPS 4175-02, “Operating Fire Stop/Break Surveillance,” Revision 12, Section I.1.d, stated, in part, “besides the listed penetrations, the entire surface of the fire rated assembly shall be inspected for open penetrations or breaks of any kind.” This surveillance was last completed in January 2005.

Contrary to the above, on May 1, 2006, the inspectors identified a breach in the wall sections that make up the 3-hour fire barrier in the Unit 2 EDG day tank room. This breach did not have an equivalent fire resistance rating and was not evaluated to ensure the adequacy to withstand the hazards associated with the area. The wall gap represented a degradation of a defense-in-depth fire protection element and compromised the 3-hour fire barrier separation requirements. However, because the finding is of very low safety significance and has been entered into the licensee’s corrective action program, IR 485432, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000237/2006007-01)**

.2 Fire Drill (Annual)

a. Inspection Scope

On June 13, 2006, the inspectors observed the licensee’s fire brigade participate in an unannounced fire drill. The drill scenario consisted of a fire in the Unit 1 craft building. Upon hearing the fire alarm, the inspectors observed the fire brigade members don their protective equipment to ensure that the brigade members were appropriately protected from the fire. The inspectors also observed the actions performed by and communications provided by the fire brigade leader to ensure that the leader demonstrated adequate command and control responsibilities, performed a proper size-up of the fire, selected the proper fire attack strategies, recognized the need for offsite assistance, and communicated with the control room. Lastly, the inspectors observed the fire brigade members during the fire attack to evaluate the appropriateness of their actions.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

1. Internal Flooding

a. Inspection Scope

The inspectors performed a review of the following:

- Unit 3 containment cooling service water vault.

The inspections focused on verifying that flooding mitigation plans and equipment were maintained as required and that the plans were consistent with design requirements. The inspection activities included, but were not limited to, visually inspecting the containment cooling service water pump vault watertight door seals, other penetration seals for pipes, and cables and the floor drains within the room. In addition, the inspectors reviewed the results of flooding related equipment surveillance tests to ensure that acceptance criteria were met, and reviewed the flooding and surveillance procedures for technical adequacy.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspectors observed an evaluation of a Senior Reactor Operator (SRO) on May 26, 2006, during the annual requalification exam. The SRO performed job performance measures (JPMs). The JPMs consisted of the isolation of the 250 VDC turbine building MCC 2 due to the MCC being damaged, and lining up reactor head cooling for alternate water injection. The inspectors verified that the SRO was able to complete the tasks in accordance with applicable plant procedures and that the success criteria as established in the job performance measures were satisfied. The inspectors observed the licensee's evaluators to ensure that no inappropriate cues were provided by the evaluators while assessing the operators' performance.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11B)

.1 Facility Operating History

a. Inspection Scope

The inspectors reviewed the plant's operating history from April 2004 through April 2006 to identify operating experience that was expected to be addressed by the Licensed Operator Requalification Training (LORT) program. It was then verified that the identified operating experience had been addressed by the facility licensee in accordance with the station's approved Systems Approach to Training (SAT) program to satisfy the requirements of 10 CFR 55.59 (c), "Requalification program requirements."

b. Findings

No findings of significance were identified.

.2 Licensee Requalification Examinations

a. Inspection Scope

The inspectors performed a biennial inspection of the licensee's LORT test/examination program for compliance with the station's SAT program which would satisfy the requirements of 10 CFR 55.59 (c)(4), "Evaluation." The operating examination material reviewed consisted of three operating tests, each containing two dynamic simulator scenarios and six JPMs. The written examinations reviewed consisted of six written examinations, each containing 37 questions. The inspectors reviewed the annual requalification operating test and biennial written examination material to evaluate general quality, construction, and difficulty level. The inspectors assessed the level of examination material duplication from week-to-week during the current year operating test. The examiners assessed the amount of written examination material duplication from week-to-week for the written examination administered in May/June 2005. The inspectors reviewed the methodology for developing the examinations, including the LORT program 2-year sample plan, probabilistic risk assessment insights, previously identified operator performance deficiencies, and plant modifications.

b. Findings

No findings of significance were identified.

.3 Licensee Administration of Requalification Examinations

a. Inspection Scope

The inspectors observed the administration of a requalification operating test to assess the licensee's effectiveness in conducting the test to ensure compliance with 10 CFR 55.59 (c)(4), "Evaluation." The inspectors evaluated the performance of two crews in parallel with the facility evaluators during four dynamic simulator scenarios and evaluated various licensed crew members concurrently with facility evaluators during the administration of several JPMs. The inspectors assessed the facility evaluators' ability to determine adequate crew and individual performance using objective, measurable standards. The inspectors observed the training staff personnel administer the operating test, including conducting pre-examination briefings, evaluations of operator performance, and individual and crew evaluations upon completion of the operating test. The inspectors evaluated the ability of the simulator to support the examinations. A specific evaluation of simulator performance was conducted and documented under Section 1R11.8, "Conformance With Simulator Requirements Specified in 10 CFR 55.46," of this report.

b. Findings

No findings of significance were identified.

.4 Examination Security

a. Inspection Scope

The inspectors observed and reviewed the licensee's overall licensed operator requalification examination security program related to examination physical security (e.g., access restrictions and simulator considerations) and integrity (e.g., predictability and bias) to verify compliance with 10 CFR 55.49, "Integrity of examinations and tests." The inspectors also reviewed the facility licensee's examination security procedure, any corrective actions related to past or present examination security problems at the facility, and the implementation of security and integrity measures (e.g., security agreements, sampling criteria, bank use, and test item repetition) throughout the examination process. Two specific corrective action reports, IR 334912 and IR 487168, were reviewed.

b. Findings

No findings of significance were identified.

.5 Licensee Training Feedback System

a. Inspection Scope

The inspectors assessed the methods and effectiveness of the licensee's processes for revising and maintaining its LORT Program up to date, including the use of feedback from plant events and industry experience information. The inspectors reviewed the licensee's quality assurance oversight activities, including licensee training department self-assessment reports. The inspectors evaluated the licensee's ability to assess the effectiveness of its LORT program and their ability to implement appropriate corrective actions. This evaluation was performed to verify compliance with 10 CFR 55.59 (c), "Requalification program requirements," and the licensee's SAT program.

b. Findings

No findings of significance were identified.

.6 Licensee Remedial Training Program

a. Inspection Scope

The inspectors assessed the adequacy and effectiveness of the remedial training conducted since the previous biennial requalification examinations and the training from the current examination cycle to ensure that they addressed weaknesses in licensed operator or crew performance identified during training and plant operations. The inspectors reviewed remedial training procedures and individual remedial training plans. This evaluation was performed in accordance with 10 CFR 55.59 (c), "Requalification program requirements," and with respect to the licensee's SAT program.

b. Findings

No findings of significance were identified.

.7 Conformance With Operator License Conditions

a. Inspection Scope

The inspectors reviewed the facility and individual operator licensees' conformance with the requirements of 10 CFR Part 55. The inspectors reviewed the facility licensee's program for maintaining active operator licenses and to assess compliance with 10 CFR 55.53 (e) and (f). The inspectors reviewed the procedural guidance and the process for tracking on-shift hours for licensed operators and which control room positions were granted watch-standing credit for maintaining active operator licenses. The inspectors reviewed the facility licensee's LORT program to assess compliance with the requalification program requirements as described by 10 CFR 55.59 (c). Additionally, medical records for ten licensed operators were reviewed for compliance with 10 CFR 55.53 (I).

b. Findings

No findings of significance were identified.

.8 Conformance With Simulator Requirements Specified in 10 CFR 55.46

a. Inspection Scope

The inspectors assessed the adequacy of the licensee's simulation facility (simulator) for use in operator licensing examinations and for satisfying experience requirements as prescribed in 10 CFR 55.46, "Simulation Facilities." The inspectors also reviewed a sample of simulator performance test records (i.e., transient tests, malfunction tests, steady state tests, and core performance tests), simulator discrepancies, and the process for ensuring continued assurance of simulator fidelity in accordance with 10 CFR 55.46. The inspectors reviewed and evaluated the discrepancy process to ensure that simulator fidelity was maintained. Open simulator discrepancies were reviewed for importance relative to the impact on 10 CFR 55.45 and 55.59 operator actions as well as on nuclear and thermal hydraulic operating characteristics. The inspectors conducted interviews with members of the licensee's simulator staff about the configuration control process and completed the IP 71111.11, Appendix C, checklist to evaluate whether or not the licensee's plant-referenced simulator was operating adequately as required by 10 CFR 55.46 (c) and (d).

b. Findings

No findings of significance were identified.

.9 Annual Operating Test Results and Biennial Written Examination Results

a. Inspection Scope

The inspectors reviewed the pass/fail results of the individual biennial written tests administered by the licensee during calender year 2005. The inspectors also reviewed the results for the operating and simulator tests (required to be given annually per 10 CFR 55.59 (a)(2)) administered by the licensee during calender years 2005 and 2006. The overall written examination and operating test results were compared with the significance determination process in accordance with NRC Manual Chapter 0609,

Appendix I, “Operator Requalification Human Performance Significance Determination Process.”

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope

The inspectors assessed the implementation of the licensee’s maintenance rule program to evaluate maintenance effectiveness for the selected systems in accordance with 10 CFR 50.65, Maintenance Rule. The following systems were selected based on being designated as risk significant under the Maintenance Rule, being in the increased monitoring (Maintenance Rule Category a(1)) group, or due to an inspector’s identified issue or problem that potentially impacted system work practices, reliability, or common cause failures:

- Unit 2/3 emergency diesel generator ventilation;
- Unit 2 low pressure coolant injection system;
- Unit 2 emergency core cooling system permissive pressure switches;
- Unit 2 standby liquid control system; and
- Unit 3 standby liquid control system.

The inspectors verified the licensee's categorization of specific issues, including evaluation of the performance criteria, appropriate work practices, identification of common cause errors, extent of condition, and trending of key parameters. Additionally, the inspectors reviewed the licensee's implementation of the Maintenance Rule requirements, including a review of scoping, goal-setting, performance monitoring, short-term and long-term corrective actions, functional failure determinations associated with the condition and issue reports reviewed, and current equipment performance status.

This represented five inspection samples.

b. Findings

Unit 2 350 psig Reactor Low Pressure Emergency Core Cooling System Permissive Switch Out-of-tolerance During Surveillance Testing

Introduction: A finding involving a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, was identified by the inspectors. The finding was associated with the licensee failure to identify an adverse trend in the performance of the 350 psig reactor low pressure emergency core cooling system (ECCS) permissive switch 2-0263-52B. The licensee failed to determine the cause of the repeated out-of-tolerance surveillance test results of the 2-0263-52B switch in 2005 and 2006, until prompted by the inspectors.

Description: During the performance of the Unit 2 quarterly Technical Specification (TS) surveillance test, DIS 1500-01, Revision 21, “Reactor Low Pressure 350 psig ECCS Permissive,” on April 19, 2006, the licensee completed the calibration and functionally tested the performance of the Unit 2 ECCS low pressure permissive switches. Each unit has two low reactor ECCS permissive pressure switches designed to permit the initiation of the ECCS subsystems during an analyzed transient between a reactor pressure of 322.1 and 355.3 psig. The result of the quarterly surveillance testing in April 2006 indicated that the 2-0263-52B ECCS permissive switch was out of TS allowable tolerance range at the low end. The licensee re-calibrated the pressure switch to within required TS tolerance and initiated IR 480479. The licensee's corrective action program review of this IR determined that the issue was not reportable.

The inspectors reviewed previous surveillance test results and identified that between January 2004 and April 2006 the Unit 2 350 psig permissive switch was found outside the TS allowable tolerance range several times. Specifically, in May 2004 during the quarterly surveillance test, the licensee identified that switch 2-0263-52B was out of the TS allowable tolerance range and that the indicator on the switch was found indicating about 45 psig with zero pressure applied. The switch was declared inoperable. The switch was immediately replaced under WO 98083028. The failure analysis report stated that there was evidence of internal mechanical problems, in that, the drive arm had slipped on the torque tube which could have accounted for the offset of the indicator at zero pressure and erratic setpoint adjustment.

In July 2005, the 2-0263-52B switch exhibited similar problems, in that it was found exceeding the TS required allowable tolerance range, and the indication pointer was reading 20 psig with zero input pressure. At that time, the licensee re-calibrated the switch back to within the TS allowable range tolerance, entered this deficiency into the corrective action program as IR 354804, but did not replace the switch. The licensee's preliminary review of IR 354804 concluded that the switch may have been out-of-tolerance from an event instead of normal drift, and therefore initiated a work request to replace the 2-0263-52B switch, and to perform a failure analysis. The switch failed its subsequent quarterly surveillance test again in October 2005, in that it was found to be outside the TS allowable tolerance range. However, 2-0263-52B was not replaced until it was once again found outside the TS allowable tolerance range in January 2006. The offsite failure analysis report, performed after the switch was replaced in January 2006, indicated an internal mechanical failure mode similar to the May 2004 event.

The inspectors questioned the licensee's staff about the justification for not replacing a safety related pressure switch following the July 2005 surveillance test failure. The licensee did not have a documented justification. The inspectors concluded that the surveillance test results of the past 2 years indicated an adverse trend in the performance of the ECCS permissive switch 2-0263-52B. The inspectors noted that the licensee failed to identify and correct the repeated out of tolerance condition. As a result of the inspectors concerns, the licensee issued IR 495327 to determine the cause and corrective actions to address the programmatic issues that allowed the Unit 2 350 psig permissive switch to repeatedly fail to meet TS requirements without the issuance of an IR to identify the adverse trend. The licensee then determined that this issue was reportable based on historical review of data and planned to initiate a Licensee Event Report.

<u>Analysis:</u> The inspectors determined that the failure to identify a condition adverse to quality and have adequate corrective actions associated with repetitive failures of a safety related instrument was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was more than minor in accordance with IMC 0612,

“Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on September 30, 2005, because it impacted the equipment performance attribute of the Mitigating System cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events. The low reactor steam dome pressure signals are used as permissive for the low pressure ECCS subsystems to inject water into the reactor. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems’ maximum design pressure. Therefore, the failure of the pressure switch could have a credible impact on safety.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, “Significance Determination Process,” Appendix A, Attachment 1, dated November 22, 2005. The inspectors concluded that the finding impacted the Mitigating Systems cornerstone. The inspectors answered “No” to all five questions under the Mitigating Systems cornerstone column, and the issue screened as having very low safety significance (Green) because the redundant switch PS 2-0263-52A passed all acceptance criteria, was operable all the time, and maintained the safety function.

The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution (corrective action) because the repeated surveillance failures of the safety related switch were not promptly identified and corrected.

<u>Enforcement:</u> Title 10 CFR, Part 50, Appendix B, Criterion XVI, “Corrective Actions,” requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected.

Contrary to the above, the licensee failed to identify an adverse trend for the repeated out of tolerance condition associated with the 2-0263-52B pressure switch, a condition adverse to quality. During this period when the switch was repeatedly out of tolerance, the calibration interval of the switch was not changed to assure the switch’s operating setpoint values stayed within the TS allowable tolerance range.

After the inspectors questioned the lack of identification of a condition adverse to quality and the untimely corrective actions, the licensee created an action item to review the cause of the event and create corrective actions. The licensee wrote Issue Report (IR) 495327, “Trending IR for 2-0263-52B exceeds TS 6 of 9 Surveillances.” The purpose of this IR was to identify why this adverse trend was not entered into the corrective action system. As immediate corrective action, the licensee reduced the surveillance frequency to adequately monitor the switch’s performance. Also the licensee required all system managers and first line supervisors to review the station procedure for the instrument performance trending program to ensure applicability and implementation, and initiated a training request for instrument maintenance technicians to include a manufacturer’s recommendation to use smaller step changes in applied pressure to improve set point accuracy. Because of the very low safety significance and because the issue is in the licensee’s corrective action program IR 495327, it is being treated as a non-cited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV05000237/2006007-02)**

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

.1 Routine Inspections

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's maintenance risk program with respect to the effectiveness of the risk assessments performed before maintenance activities were conducted on structures, systems, and components and verified that the licensee managed the risk in accordance with 10 CFR 50.65, "Maintenance Rule." The inspectors evaluated whether the licensee had taken the necessary steps to plan and control emergent work activities. The inspectors also verified that equipment necessary to complete planned contingency actions was staged and available. The inspectors completed evaluations of maintenance activities on the:

- Unit 3 Division 1 low pressure coolant injection and containment cooling service water pumps out-of-service for planned maintenance;
- Unit 2 standby liquid control out-of-service for accumulator replacement, squib valve, and oil change;
- Unit 3 high pressure coolant injection system out-of-service for planned maintenance;
- Unit 2 reactor protection system bus swap to reserve power; and
- Unit 2 and 3 containment isolation associated with the high pressure coolant injection system pipe replacement.

This represented five inspection samples.

b. Findings

No findings of significance were identified.

.2 Failure to Post Protective Pathway Signs During Unavailability of Torus to Reactor Building Vacuum Breaker

a. Inspection Scope

The inspectors reviewed risk assessment and controls for maintenance activities on the Unit 2 air operated 2-1601-20B vacuum breaker valve between the Unit 2 torus and the reactor building.

b. Findings

Introduction: The inspectors identified a non-cited violation of 10 CFR 50.65 (a) (4), having very low safety significance (Green) associated with inadequate management of risk. While working on the Unit 2 1601-20B reactor building to torus vacuum breaker relief valve the Unit 2 risk status was designated as "yellow" and would have gone to "red" if the 2-1601-20A valve was also taken out-of-service. The 2-1601-20A vacuum relief valve was not clearly indicated as a protected pathway and station personnel were not notified of its' "yellow" risk status either through the pre-job brief, posted markings, Plan Of The Day meeting (POD), or POD meeting documentation.

Description: On May 15, 2006, the inspectors toured the Unit 2 torus catwalk area as repair work was being performed on the Unit 2 1601-20B reactor building to torus vacuum relief valve. Unit 2 was on-line at full power. The vacuum breakers relieve pressure to the torus to prevent exceeding the external torus pressure. The inspectors noticed that there were no protected pathway signs posted on or near the remaining vacuum breaker 2-1601-20A. Unit 2 was in a “yellow” risk condition from 11:06 a.m. to 12:22 p.m. on May 15, 2006, due to the unavailability of the 2-1601-20B valve and would have gone to red risk if the 2-1601-20A valve had been made unavailable.

There was no mention in the POD meeting on May 15, 2006, of Unit 2 being in a “yellow” risk condition for the Unit 2 1601-20B valve work or that the 2-1601-20A valve was a protected pathway. Additionally, neither was the risk condition documented in the plant status sheet for the day or in the schedule review sheet for the day as being “yellow,” nor was 2-1601-20A listed as a protected pathway. The inspectors reviewed procedure, MA-AA-743-310, “Diagnostic Testing And Evaluation Of Air Operated Valves,” Revision 4, and WO 99213710-01, and discovered that the pre-job briefing checklist designated protected pathways and equipment as not applicable (NA).

The inspectors reviewed procedure, WC-AA-101, “On-Line Work Control Process,” Revision 12. In Attachment 3, this procedure ranked the four configuration risk conditions: green, yellow, orange, and red. Green is the least configuration risk and red is the worst or discussed as an unacceptable risk condition. Green is optimal defense in depth or no appreciable increase in initiating event frequency or decrease in mitigation capability. Yellow is nominal defense in depth. Orange is marginal defense in depth or significant increase in initiating event frequency or decrease in mitigation capability. Red is unacceptable defense in depth or unacceptable increase in initiating event frequency or decrease in mitigation capability.

The inspectors discussed their concern with a lack of a protected pathway for the 2-1601-20A valve with the licensee on May 15, 2006. The licensee documented the issue in IR 490307 the same day. The licensee concluded that the vacuum breaker valves were not, but should have been, on the Paragon Model “remain-in-service list” for protected pathway per ER-AA-600-1042, “On- Line Risk Management,” Revision 4.

Based on the inspectors’ finding, the licensee performed an extent of condition by reviewing the Paragon Model component list to identify any other components that should be on the protected pathway remain-in-service list. The review looked for items that could cause the configuration risk to change from “yellow” to “orange” or “red” if the protected pathway component was also taken out-of-service. The licensee performed a thorough review and found six other Unit 2 components that could cause the on-line risk to go from “yellow” to “orange” or “red” due to components being taken out-of-service for surveillance testing or for components that are normally repaired or replaced during an outage but may be repaired or replaced while on-line. Four components were identified for the risk configuration heat removal function and included containment cooling service water discharge valves 2A and 2B and torus cooling trains 2A and 2B. Two other components were identified for the reactivity control function and included ATWS RPT Trip Logic A and Trip Logic B. These components were documented in IR 490307. The same components for Unit 3 were also not on the remain-in-service list and should have been to prevent the risk from becoming “orange” or “red” if the protected pathway component was taken out-of-service.

Analysis: The inspectors concluded that the failure to identify and protect redundant risk important equipment was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, " Issue Screening," issued on September 30, 2005. Failure to notify plant personnel of risk conditions that are "yellow" and that could change to "red" or "orange" if the redundant component is taken out-of-service could become a more significant safety concern if left uncorrected. This deficiency in the protected pathway program could affect the availability and capability of components and systems that respond to initiating events. Failure to be aware of all the components and systems that could cause an elevated "orange" or "red" risk condition increases the probability that the mitigating systems or components will be taken out-of-service and that they would not be able to respond as designed to an initiating event or accident condition.

The inspectors completed a Phase 1 "Significance Determination Process," of IMC 0609 Appendix A, Attachment 1, dated November 22, 2005. The inspectors determined that this finding impacted the Barrier Integrity cornerstone column. The inspectors answered "No" to all three questions under the Barrier Integrity column on page A1-9 because no actual barrier failure occurred. Therefore, the issue screened out as having very low significance (Green).

The inspectors also concluded that this finding affected the cross-cutting issue of human performance (resources) because the procedure did not list this component as requiring a protected pathway. Specifically, sufficient guidance did not exist in the Paragon Model remain-in-service list for a protected pathway per ER-AA-600-1042, "On-Line Risk Management," Revision 4.

Enforcement: Title 10 CFR 50.65 (a) (4) states, "before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.

Licensee procedure WC-AA-101, On-Line Work Control Process, Revision 12, Attachment 7, required that, "in even the cases of short equipment duration unavailability, a heightened level of sensitivity to the protected equipment must be maintained and it is the responsibility of every department to ensure that personnel working in the plant are informed as to what components are protected." The procedure also stated in Section 4.1.4 that actions shall be taken to protect redundant structures, systems, or components if loss of the redundant component would cause entry into a "red" or "orange" risk configuration.

Contrary to the above, from 11:06 a.m. to 12:22 p.m. on May 15, 2006, the licensee did not assess and manage the increase in risk, in that, Unit 2 was in a "yellow" risk condition due to the unavailability of the 2-1601-20B valve and would have gone to "red" risk if the 2-1601-20A valve had been made unavailable. The licensee took no actions to protect redundant structures, systems, or components. The 2-1601-20A valve was not marked as a protected pathway. In addition, the licensee did not alert all departments to the protected pathways through normal methods such as the POD meeting on May 15, 2006, or the plant status sheet for the day or in the schedule review sheet for the day.

Furthermore, the licensee identified that the reason this happened was that procedure ER-AA-600-1042, "On-Line Risk Management," Revision 4, did not specify that the 2-1601-20A and 2-1601-20B valves were components that needed protected pathways on the redundant components. Additional licensee review identified six other components for each unit that should have been listed in the Paragon Model remain-in-service list while their redundant component was being repaired or replaced on-line. The licensee has since added the omitted eight components for each unit to their remain-in-service list in ER-AA-600-1042 for protected pathway components that can change risk to "orange" or "red" if removed from service. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as IR 490307, this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000237/2006007-03)**

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

.1 Failure to Perform Procedure Steps in the Proper Sequence by Operations Caused Emergency Safety Feature Systems Actuation

a. Inspection Scope

On April 5, 2006, during the swap of the 3A reactor protection system (RPS) bus to reserve power to support repair of the 3B RPS motor generator (MG) set, the Unit 2/3 standby gas treatment auto started and a Unit 3 reactor building ventilation isolation occurred. The licensee determined that the cause of this issue was a human performance error for the failure to perform steps in the proper sequence. All systems were restored in accordance with plant procedures and there was no equipment that was damaged or any personnel that were injured. The licensee entered this issue into their corrective action program as IR 475365.

This represented one inspection sample.

b. Finding

Introduction: A Green finding involving a non-cited violation of TS 5.4.1 was self revealed when an auxiliary nuclear station operator (Aux NSO) and a unit supervisor (US) were performing Dresden Operating Procedure (DOP) 0500-03, "Reactor Protection System Power Supply Operation," Revision 27. The Aux NSO and the US did not verify that the area radiation monitor's (ARM) power supply voltage was normal and did not reset all trips on the ARM modules prior to removing a jumper that was installed. This required entry into TS 3.6.4.1 Limiting Condition of Operation, Action A for reactor building low differential pressure (D/P).

Description: On April 5, 2006, operations department staff were placing the 3A reactor protection system (RPS) bus to reserve power from the normal power source to support repair of the 3B RPS motor generator (MG) set using DOP 0500-03. The operators reset a half scram that was expected during this activity and then they proceeded with removing a jumper that was installed, in accordance with the procedure, to allow the transfer. Following the removal of the jumper, the Unit 3 reactor building ventilation tripped and the Unit 2/3 standby gas treatment train auto started. Neither the Aux NSO nor the US verified that the ARM power supply was indicating normal and that the 3A reactor building ventilation and reactor building fuel pool channel ‘A’ ARMs were reset prior to jumper removal as required by attachment A of DOP 0500-03. Procedure HU-AA-101,“Human Performance Tools and Verification Practices,” Revision 3, required the individuals to agree that the system was ready for the action prior to performing the action. The US failed to verify that the system was reset or to check the proceeding steps had been completed prior to going into the next step. Both operators had been provided with marked up copies of the procedure, and briefed on jumper placement and removal and on the use of concurrent verification prior to the event.

Analysis: The inspectors determined that the failure to implement procedure instructions for performing the swap of the RPS buses to support a planned maintenance activity, that impacted safety-related equipment, was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with Inspection Manual Chapter (IMC) 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on September 30, 2005, because it impacted the structures, systems, and components attribute of the Barrier Integrity cornerstone (containment) objective. This deficiency challenged a safety system and could have affected the availability and capability of components and systems that respond to initiating events.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, “Significance Determination Process,” Appendix A, Attachment 1, dated November 22, 2005, and determined that this finding impacted the Barrier Integrity cornerstone column. The inspectors answered “Yes” to question #1 under the Barrier Integrity column on page A1-9. Therefore, the issue screened out as having very low significance (Green).

The inspectors also concluded that this finding affected the cross-cutting issue of human performance (personnel) because the Aux NSO and the US failed to utilize human performance error prevention techniques required to safely implement the station procedure.

Enforcement: Technical Specification 5.4.1 required, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978, paragraph 1.j required administrative procedures for the bypassing of safety functions and jumper control.

Station procedure DOP 0500-03, Attachment A, “Bypassing and Restoration of Secondary Containment Isolations and SBGT Initiations When De-Energizing ‘A’ RPS Bus,” Revision 27, Removing Jumpers Step 1, stated, “Prior to jumper removal verify ARM power supply 2(3)-1705-7A at 902(3)-10 is indicating normal voltage compared to other power supply;” and Step 2, “Reset ALL trips on the 902-(3)-10 ARM Modules AND verify annunciators are reset.

Contrary to the above, on April 5, 2006, neither the NSO nor the US, verified that the ARM power supply 2(3)-1705-7A at 902(3)-10 was indicating normal voltage compared to the other power supply or reset all trips on the 902-(3)-10 ARM Modules or verified that the annunciators reset prior to removing jumpers identified in procedure DOP 0500-03, Revision 27.

Both the Aux NSO and the US had been provided with marked up copies of the procedure, and were briefed on jumper placement and removal and on the use of concurrent verification. As immediate corrective action, the two individuals were temporarily removed from licensed shift duties. The operations department was tasked to develop a dynamic learning activity for placekeeping and jumper manipulation for all operations personnel, and to create an internal OPEX to communicate lessons learned. Because this violation was of very low safety significance and it was entered into the licensee's corrective action program IR 475365, this violation is being treated as non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000249/2006007-04)**

.2 Unit 2 High Pressure Coolant Injection (HPCI) System Declared Inoperable

a. Inspection Scope

The inspectors reviewed the Apparent Cause Report for IR 475721, "Shorted Power Lead While Replacing HPCI Temperature Recorder," and Licensee Event Report 237/2006-002-00, "Unit 2 High Pressure Coolant Injection System Declared Inoperable."

This represented one inspection sample.

b. Findings

Introduction: A Green finding was self-revealed when an instrument maintenance technician shorted a power lead while performing modification work that resulted in the Unit 2 HPCI system becoming inoperable for 2 hours and 14 minutes on April 6, 2006. This finding was not considered a violation of regulatory requirements.

Discussion: Instrument maintenance technicians were replacing the Unit 2 HPCI temperature recorder on April 6, 2006. During re-installation of the recorder the technician shorted the power lead against the recorder mounting bracket screw. This resulted in the transfer of the essential service system bus to its emergency power supply from motor control center 28-2 and the trip of essential service system circuit 16. This resulted in the HPCI system being inoperable due to a loss of its automatic function from the loss of power to its flow controller and signal converter. The system was available because control room personnel could have manually controlled system operation.

Analysis: The inspectors determined that the failure to ensure that the hot power lead would not come into contact with any piece of the recorder or cabinet that could cause it to short to ground was a performance deficiency warranting a significance evaluation in accordance with IMC 0612, Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on September 30, 2005. This finding was more than minor because it involved the Human Performance attribute of the Mitigating Systems objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the finding using the SDP in accordance with IMC 0609, "Significance Determination Process," because the finding was associated with the Mitigating Systems cornerstone. Specifically, it impacted the short term heat removal degraded attribute found on page A1-7 of Appendix A. The inspectors performed a Phase I screening of the finding. The inspectors answered "No" to all five questions under the

Mitigating Systems cornerstone column on page A1-9 and therefore the issue screened as very low safety significance (GREEN). In addition, the HPCI system was inoperable for a short time period and could have been manually controlled in the event of an accident.

The inspectors also concluded that this finding affected the cross-cutting issue of human performance (personnel). Technicians failed to use appropriate human performance techniques to safely implement the procedure. Specifically, the instrument maintenance technician failed to recognize the potential hazard and tape off the mounting bracket screw that caused the short to ground.

Enforcement: The instrument maintenance technician was performing work in accordance with the work package. The licensee communicated that error prevention work practices expect the technician to identify and tape off the section of the mounting bracket that the power lead contacted to prevent an inadvertent short, but the work practices do not procedurally require that action. Therefore, no violation of regulatory requirements occurred. This issue was considered a finding of very low safety significance **(FIN 05000237/2006-007-05)**. This issue was entered into the licensee's corrective action program as IR 475721. Licensee Event Report 237/2006-002-00, "Unit 2 High Pressure Coolant Injection System Declared Inoperable" is closed.

.3 Unit 2 2D1 Feedwater Heater Normal Level Control Valve Closed

a. Inspection Scope

The inspectors reviewed personnel performance during planned and unplanned plant evolutions. The review was performed to ascertain that operators' responses were in accordance with the required procedures.

On April 14, 2006, the Unit 2 2D1 feedwater heater normal level control valve closed. The licensee entered Dresden Operating Abnormal procedure DOA 3500-02, "Loss of Feedwater Heaters." The licensee initiated a prompt investigation into the issue and determined that the cause of this event was a faulty level switch. The faulty switch was replaced and the licensee entered this issue into their corrective action program as IR 478794.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Routine Inspections

a. Inspection Scope

The inspectors reviewed operability evaluations (OE) to ensure that operability was properly justified and the component or system remained available, such that any non-conformance conditions were in compliance with Generic Letter 91-18, "Information to Licensees

Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability." The review included issues involving the operability of:

- Engineering Change/Evaluation #359519, MR-90 Technical Evaluation to support shoring for trenching of underground piping and tank 2/3 B condensate storage tank;
- Engineering Change/Evaluation #342944, Unit 3 containment cooling service water system water hammer loss of keep-fill analysis; and
- Document # 0006216498, dated July 7, 2000, "Dresden Unit 2 High Pressure Coolant Injection Room Cooler Operability."

This represented three inspection samples.

b. Findings

No findings of significance were identified.

.2 Standby Liquid Control Valves Installed In The Plant Different Than Those Assumed In A Design Calculation

a. Inspection Scope

The inspectors reviewed IR 488251, "Non-Conservative Inputs Used In SBLC [standby liquid control] Pressure Drop Calculation;" IR 487350, "Standby Liquid Control Valves Do Not Match Calculation;" and Engineering Change Evaluation (EC) 360883, "Impact of Incorrect SLCS [standby liquid control system] Pressure Drop Input on ATWS [anticipated transient without scram] Analysis." In addition, the inspectors interviewed design and system engineering personnel.

This represented one inspection sample.

b. Findings

Introduction: The inspectors identified a finding involving a violation of 10 CFR 50.62, having very low safety significance (Green) associated with a licensee-identified material condition. The licensee identified that the inputs to a design analysis (DRE01-0066, "Dresden Unit 2 & 3 Standby Liquid Control System Discharge Piping Pressure Drop," Revision 1) were non-conservative. Some of the valves actually installed in the plant were not the same type of valves assumed to be installed in the design analysis. This ultimately resulted in a change in a design calculation that demonstrated that standby liquid control system relief valves could lift upon system initiation during an anticipated transient without scram (ATWS) event.

Description: On May 5, 2006, during a system walkdown the licensee identified that valves 2/3-1101-2A & 2B, 2/3-1101-23, and 2/3 1101-1 are globe valves rather than gate valves and valves 2/3-1101-43A & 43B, 2/3-1101-15 & 16 are lift check valves rather than swing check valves as shown in calculation DRE01-0066, Revision 1.

The impact of having some of the valves actually installed in the plant that were not the same type of valves assumed to be installed in the ATWS Analysis was that it resulted in a higher pressure drop between the pump discharge and the reactor than calculated in DRE01-0066, Revision 1. This higher pressure drop meant that pump discharge pressure had to be higher to get flow to the reactor and the SBLC system relief valves could lift during an ATWS event. The lifting of the relief valves would cause SBLC system flow to be recirculated to the system storage tank rather than injected into the reactor vessel. Due to the inability to provide continuous SBLC system design flow into the reactor vessel as required by 10 CFR 50.62.c.(4), the licensee would fail to comply with 10 CFR 50.62.c.(4) if the relief valve lifted.

A licensee contractor revised calculation DRE01-0066 using the installed valve types. The results indicated that based on a two pump flow of 88 gallons per minute, the calculated system pressure loss increased to 215 psig for Unit 2 (as compared to 141 psig) and 362 psig for Unit 3 (as compared to 232 psi). Based on these results the licensee concluded that the SBLC relief valves would lift, during two pump flow, under the condition when SBLC was required to inject into the vessel.

The licensee performed Engineering Change (EC) 360883 to document the justification for operability basis stated in IR 488251, “Non-Conservative Inputs Used In SBLC Pressure Drop Calculation.” Because the revision to calculation DRE01-0066 had not been completed at the time EC 360883 was performed, the licensee assumed higher values of pressure drop in EC 360883 than what was eventually determined to be accurate in DRE01-0066, Revision 2. The licensee assumed a 300 psig drop for Unit 2 and a 390 psig drop for Unit 3 when performing EC 360883. The licensee analyzed for a failed open pressure regulator along with a failure of the alternate rod insertion system. This was assumed to be the most limiting transient. The licensee concluded that vessel peak pressure and temperature, and also peak cladding temperature would not be impacted by the increase in SBLC pressure drop since they occur before the SBLC system would be initiated. In addition, the licensee assumed the event duration was short enough that fuel clad oxidation was not an issue. The licensee did conclude that delayed SBLC system injection would have an impact on the maximum suppression pool temperature and pressure. The licensee concluded that with the assumed higher calculated pressure drops (300 psig and 390 psig), suppression pool temperature could be maintained at an acceptable level, but only by taking credit for the reactor cooling provided by the isolation condenser.

The licensee took several conservativisms in EC 360883. For example, all the reactor relief valves were assumed to open at their set point plus three percent and both SBLC system relief valves were assumed to open at their set point minus 3 percent. In addition, the licensee assumed that both SBLC system relief valves would open instead of the more likely scenario that only one would open. If one SBLC relief valve remained closed more flow would be available to the reactor.

<u>Compliance with the 10 CFR 50.62</u>

The inspectors used the above information to determine that the potential to lift the SBLC relief valve resulted in the licensee being outside of the design basis and in noncompliance with 10 CFR 50.62 because the system would be unable to meet the required injection flow rate and boron concentration during the time the relief valves were lifting.

To achieve compliance with 10 CFR 50.62, the licensee planned to increase SBLC boron enrichment from greater than or equal to 30 atom percent boron-10 to greater than or equal to 45 atom percent boron-10. This would allow the licensee to provide the acceptable amount of boron per 10 CFR 50.62 while using only one pump. In addition, licensee's calculation DRE01-0066, Revision 2, demonstrated that the use of one SBLC pump would not result in lifting a SBLC relief valve. The licensee planned to fill the SBLC tank with the enriched boron on each unit during the next refueling outages.

Review of TS Operability

Technical Specification Surveillance Requirement 3.1.7.7 required the licensee to demonstrate that each SBLC pump was capable of pumping at a rate of at least 40 gpm with a discharge pressure of greater than or equal to 1275 psig. The inspectors reviewed additional information on the relief valves and determined that due to differences in system head losses during one and two pump system operation, the licensee could inject flow into the reactor with one pump at the rate specified in TS Surveillance Requirement 3.1.7.7 without lifting the relief valves. Based upon the continued ability to satisfy TS Surveillance Requirement 3.1.7.7, the licensee determined that the SBLC system remained operable even though the licensee was unable to continuously inject 86 gpm of sodium pentaborate solution as required to meet 10 CFR 50.62. In addition, the TS Basis stated that with one subsystem inoperable the requirements of 10 CFR 50.62 cannot be met, however, the remaining subsystem is still capable of shutting down the unit.

The Office of Nuclear Reactor Regulation also determined in Task Interface Agreement 2001-12, for a similar issue at the Susquehanna plant, that although the licensee was not in compliance with 10 CFR 50.62, the standby liquid control system remained operable as required by TS 3.1.7. This determination was based upon information contained in NUREG-1433, "Standard Technical Specifications General Electric Plants," which states that TS 3.1.7 does not require meeting the requirements of 10 CFR 50.62 to meet the associated TS Limiting Condition for Operation. Based upon this information, the inspectors concluded that no violation of TSs occurred.

Analysis: The inspectors determined that the failure to comply with 10 CFR 50.62 was a performance deficiency warranting a significance determination. The inspectors concluded that the finding was greater than minor in accordance with IMC 062, "Power Reactor Inspection Reports," Appendix B, "Issue Disposition Screening," issued on September 30, 2005. This finding involved the attribute of design control and could have affected the Mitigating Systems objective of ensuring the capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors completed a significance determination of this issue using IMC 0609, Significance Determination Process," dated November 22, 2005. The finding was associated with the Mitigating Systems cornerstone. Specifically, it impacted the reactivity control degraded attribute found on page A1-7 of Appendix A. The inspectors performed a Phase I screening of the finding. The inspectors answered "Yes" to question 1, under the Mitigating System cornerstone on page A1-9, "is the finding a design or qualification deficiency confirmed not to result in loss of operability per Part 9900, Technical Guidance, Operability Determination Process for Operability and Functional Assessment," and therefore the issue screened as very low significance (Green). The SBLC system could be recovered during an ATWS event. Cycling of the relief valves would not prevent most of the borated solution from being injected into the reactor pressure vessel, and the licensee was able to demonstrate that the reactor remained within the acceptance criteria of their original ATWS analyses even if no boron solution was injected into the reactor pressure vessel while the relief valves lifted.

Enforcement: Part 50.62 of Title 10 CFR requires, in part, that each boiling water reactor must have a SBLC system with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate that the resulting reactivity control was at least equivalent to that resulting from the injection of 86 gpm of 13 weight percent sodium pentaborate decahydrate (boron) solution.

Contrary to the above, the licensee has failed to have, since 1984, a SBLC system with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate that the resulting reactivity control was at least equivalent to that resulting from the injection of 86 gpm of 13 weight percent sodium pentaborate decahydrate (boron) solution. This condition was considered a performance deficiency.

To achieve compliance with 10 CFR 50.62, the licensee planned to increase SBLC boron enrichment from greater than or equal to 30 atom percent boron-10 to greater than or equal to 45 atom percent boron-10. This would allow the licensee to provide the acceptable amount of boron per 10 CFR 50.62 while using only one pump. In addition, licensee's calculation DRE01-0066, Revision 2, demonstrated that the use of one SBLC pump would not result in lifting a SBLC relief valve. The licensee planned to install the enriched boron on each unit during the next refueling outages. The inspectors questioned why the boron enrichment could not be accomplished during a forced outage. The licensee wrote IR 507856 to address this question. The answer was not obtained by the end of the inspection period.

Because this violation was of very low safety significance and it was entered into the licensee's corrective action program as IR 488251, this violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000237/2006-007-05; 05000249/2006-007-05)**.

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 in TSs or other design documents. 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 post-maintenance testing activities associated with the following:

- Unit 2 planned maintenance on torus to reactor building vacuum relief air operated valve 2-1601-20B;
- Unit 3 planned maintenance on LPCI loop I full flow bypass test inboard MOV 3-1501-20B;
- Unit 3 planned maintenance on LPCI loop I and loop II cross-tie MOV 3-1500-32B;

- Unit 3 planned maintenance on LPCI loop II full flow bypass outboard test MOV 3-1500-38B; and
- Unit 2 replacement of the 2-1641-17A torus to reactor building d/p relay.

This represented five inspection samples.

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 TSs. 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 inspectors observed surveillance testing activities and/or reviewed completed packages for the tests, listed below, related to systems in the Initiating Event, Mitigating Systems, and Barrier Integrity cornerstones:

- Unit 2 DOS 1400-05, "Core Spray System Pump Operability and Quarterly Inservice Testing (IST) with Torus Available," Revision 32;
- Unit 3 DOP 2000-24,"Drywell Sump Operation," Revision 13;
- Unit 3 DOS 6600-12, "Diesel Generator Tests Endurance and Margin/Full Load Rejection/ECCS/Hot Restart," Revision 34;
- Unit 2 EPAs MA-DR-773-732, "Calibration/Functional Test of Reactor Protection System 2A Motor Generator Set," Revision 03;
- Unit 3 DOS 1500-02, "Containment Cooling Service Water Pump Test and Inservice Test (IST)," Revision 56;
- Unit 3 DIS 1500-29, "Low Pressure Coolant Injection System Division 1 Logic System Functional Testing," Revision 04; and
- DES 8300-50, "125 Volt DC Battery Charger Capacity Test for Charger 2-83125-2A," Revision 3.

This represented a total of seven inspection samples, of which two were In Service Testing, one was Reactor Coolant System Leak Detection, and four were Routine Surveillance.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors screened one active temporary modification and assessed the effect of the temporary modification on safety-related system functions as specified in the Updated Final Safety Analysis Report and TSs. The inspectors also determined if the installation was consistent with system design.

- Temporary Modification 360461, "Install Temporary Heater to Support SBLC Heat Tracing for Suction Line," Revision 0

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill and Training Evaluations (71114.06)

May 31, 2006, Emergency Preparedness Performance Indicator

a. Inspection Scope

The inspectors observed station personnel during a licensee-only-participation emergency preparedness training exercise on May 31, 2006. The inspectors evaluated the effectiveness of drill participants and the adequacy of the licensee's critique in identifying weaknesses and failures. The drill scenario involved the reactor protection system failure to initiate an automatic scram and initiation of the alternate rod insertion system.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

4OA1 Performance Indicator Verification (71151)

Cornerstones: Initiating Events and Mitigating Systems

.1 Reactor Safety Strategic Area

A. Inspection Scope

The inspectors sampled the licensee's records associated with the two initiating event performance indicators (PI) listed below for Units 2 and 3. Specifically, the inspectors looked at the period from the first quarter of 2004 through the fourth quarter of 2005. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 3, were used to verify the basis in reporting for each data element. The inspectors reviewed portions of the operations logs and raw PI data developed from the monthly operating reports and discussed methods for compiling and reporting the PIs with cognizant licensee personnel. The inspectors compared graphical representations from the most recent PI report to the raw data to verify that the data was correctly reflected in the report. Licensee event reports (LERs) issued during the referenced time frame, operating logs, and the unit nuclear station operator daily surveillance log for reactor coolant system leakage were also reviewed. All data reviewed covered the period from April 2004 through March 2006. The inspectors discussed methods for compiling and reporting the PIs with cognizant licensee personnel.

- Safety System Functional Failures, Units 2 and 3
- Unplanned Transients per 7000 Critical Hours, Units 2 and 3

This represented four inspection samples.

b. Findings

No findings of significance were identified

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Quarterly Review

Review of Licensee’s Response to the Unit 2 “A” Electrohydraulic Control System (EHC) Pressure Regulator Issue

On March 24, 2005, Unit 2 received two unexpected control room alarms due to an EHC system malfunction. Several seconds later, Unit 2 experienced a steam transient which caused a Group 1 isolation and scram. The licensee initiated IR 316625 and initiated a prompt investigation to ensure the details regarding this event were appropriately captured and corrected.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed the information provided in IR 316625 and the associated root cause report to verify that the licensee’s identification of the problems was complete, accurate, and timely, and that the consideration of extent of condition review, generic implications, and common cause was adequate.

(2) Issues

There were no issues in the area of Effectiveness of Problem Identification.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The inspectors considered the licensee's evaluation and disposition of performance issues, and application of risk insights for prioritization of issues.

(2) Issues

There were no issues in the area of Prioritization and Evaluation of Issues.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the licensee's corrective actions which resulted from the root cause report associated with IR 316625 to determine if the IR addressed generic implications and that corrective actions were appropriate.

(2) Issues

The inspectors reviewed the licensee's actions and concluded that the actions were comprehensive. Although the cause of the scram was unable to be determined, the most probable cause was attributed to an increase in electrical resistance between electrical pins on the A54 circuit card within the EHC system. The card was removed from service and sent to an independent laboratory for additional testing. No obvious deficiencies were identified. The licensee closed the corrective action assignment by completing the work request and repairing the remaining connectors to the "A" EHC pressure regulator "A54" card during the November 2005 Unit 2 refueling outage. The inspectors verified that the licensee completed all corrective actions assigned. However, the corrective action system documentation did not appropriately reflect that the work was completed.

This represented one inspection sample.

.2 Semiannual Review for Trends

a. Inspection Scope

The inspectors performed a review of the licensee's corrective action program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspector's review consisted of a 6 month period from January 2006 through June 2006, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors reviewed multiple issue reports generated during the time period, in an attempt to identify potential trends. The screening was accomplished as follows:

1. IRs dealing with company policies, administrative issues, and other minor issues were eliminated as being outside the scope of this inspection;

2. The IRs were sorted into categories involving same equipment problems, repetitive issues, reoccurring departmental problem/challenges and repeated entries into TSs. The IRs were then screened for potential common cause issues and considered for potential trends;

3. The inspectors removed groups of IRs that discussed strictly programmatic problems because the inspection requirement was primarily for equipment problems and human performance issues;

4. The inspectors also removed groups of IRs where their review indicated that duplicate IRs had been written for the same event or failure;

5. The remaining groups, considered potential unidentified trends, were provided to the licensee for discussion in case there was extenuating information that the inspectors were not aware of; and

6. Groups of IRs remaining after all of the above screening were considered trends which the licensee had failed to identify.

7. The inspectors then were able to make an assessment by comparing the trends identified by the licensee to those trends identified by the NRC.

In addition, the inspectors reviewed corrective action backlog lists and all of the nuclear oversight assessments and audits conducted during January 2006 to June 2006.

This represented one inspection sample.

b. Findings

There were no findings of significance identified. The inspectors determined that licensee employees were writing IRs at an appropriate threshold, and that employees at all levels of the organization were writing IRs. The inspectors determined that the licensee had identified issues adequately and appropriately entered them into the corrective action program. Overall, the inspectors identified the same specific trends as the licensee.

4OA5 Other Activities (71153)

(Closed) Unresolved Item 05000237/97019-04; 05000249/97019-04 Concrete Expansion Anchor (CEA) Safety Factor (SF) for High Energy Line Break (HELB) Pipe Whip Restraints. TAC Nos. MB7297 through MB7300.

The inspectors were concerned that anchor bolts for HELB pipe whip restraints at the Dresden and Quad Cities stations were designed with a minimum SF of 2.0, which was less than the SF of 4.0 they expected. (Reference Quad Cities Inspection Followup Item 05000254/96011-06; 05000265/96011-06). Subsequently, the licensee performed additional analysis, and determined that there are five CEAs at Quad Cities, and one CEA at Dresden that have a designed factor of safety between 2.5 and 3.8. These CEAs are used in pipe whip restraints (HERs) provided for high energy line break mitigation. CEAs used to satisfy seismic design requirements must have a SF of 4.0 or greater. CEAs used for other applications, such as HERs, are typically designed with a SF of 4.0.

An Internal NRC Memorandum (R. Capra to J. Grobe) dated, July 23, 1997, responded to an NRC Region III Request for Technical Assistance (Task Interface Agreement (TIA) 96-0325) (G. Grant to J. Roe) dated, September 20, 1996, and provided the NRC Office of Nuclear Reactor Regulation (NRR) evaluation of the issue.

Additional discussions and correspondence between the licensee and NRC staff occurred with respect to this issue. Additional onsite inspection of this issue occurred as indicated in NRC Integrated Inspection Report 05000254/03-02; 05000265/03-02.

Docketed correspondence between the NRC and the licensee included the following:

Letter from NRC to L. Pearce (ComEd) dated December 16, 1997;

Letter from J. Heffley (ComEd) to NRC dated January 9, 1998;

Exelon Response to Verbal Request for Additional Information (K. Jury (Exelon) to NRC Document Control Desk) dated September 11, 2002;

NRC Request for Additional Information, M. Banerjee (NRC) to C. Crane (Exelon) dated, August 10, 2004; and

Exelon Response to Request for Additional Information (P. Simpson to NRC Document Control Desk) dated, September 30, 2004.

There is no specific regulatory requirement or commitment regarding the SF for these CEAs. Therefore, the staff did not identify any non-compliance with a specific regulatory requirement. However, in order to ensure that adequate protection exists given the smaller SFs, the staff requested the licensee to provide a bounding type of analysis to discuss the safety impact of these CEAS failing to perform their safety function upon a postulated failure of the pipe (a beyond design basis analysis).

The licensee provided the requested analysis in the letter dated, September 30, 2004, (available in the NRC agencywide document access and management system (ADAMS) under accession number ML042820219). The staff reviewed this analysis and performed a walkdown of the plant areas where some of the protected equipment is located. The following provides a summary of the licensee's response and the staff's observation during the walkdown regarding the safety impact of postulated failures of the subject CEAs (for Dresden) to restrain the high energy line in the unlikely event of a total circumferential break:

<u>Dresden HER PWHP-3</u>

This anchor is located on the high pressure coolant injection (HPCI) steam line in the torus area. During a postulated HPCI steam line circumferential break, if this anchor fails, the whipping pipe could damage certain safety related motor operators for valves in the low pressure coolant injection (LPCI) system (not crediting several structural elements in between the pipe and the valve operators). These valves are in the return line to the torus for one of the redundant torus cooling/spray loops, and hence damage to these valves could cause the loss of one of the two loops of the suppression pool cooling system. The high HPCI steam flow out the ruptured pipe will isolate the system, thus terminating the flow. The operators will use symptom based emergency operating procedures (EOPs) to shutdown the reactor from the control room. The suppression pool cooling system is not required to mitigate the accident, as the isolation condenser system will be available to remove decay heat before normal shutdown cooling could be initiated. Additionally, the main condenser should also be available if the high steam flow does not isolate the main steam lines.

Conclusion

Based on a review of the information that was provided, the staff agrees that there is reasonable assurance that the plant can be safely shutdown in the event of a circumferential pipe break, and subsequent failure of its related CEA(s) as described above. Therefore, adequate protection exists for a postulated beyond design basis event when the subject CEAs with a SF of less than 4.0 are assumed to fail after a high energy line break. Hence, no further regulatory action is warranted relative to this issue. The TAC Nos. MB7297 through MB7300 are closed. This unresolved item is also closed.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to the Plant Manager, Mr. D. Wozniak, and other members of licensee management on July 18, 2006. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was discussed.

.2 Interim Exit Meetings

Interim exit meetings were conducted for:

Biennial Operator Requalification Program Inspection with Mr. D. Wozniak, Plant Manager, on May 19, 2006.

Biennial Operator Requalification Program Inspection with Mr. G. Graff, Operations Training Manager, on June 12, 2006, via telephone.

Unresolved Item 05000237/97019-04; 05000249/97019-04 closure with Mr. D. Wozniak on June 19, 2006.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

D. Bost, Site Vice President
D. Wozniak, Plant Manager
C. Barajas, Senior Operations Supervisor
H. Bush, Radiation Protection Manager
J. Ellis, Regulatory Assurance Manager
R. Ford, Emergency Preparedness Manager
R. Gadbois, Operations Director
D. Galanis, Design Engineering Manager
V. Gengler, Dresden Site Security Director
G. Graff, Operations Training Manager
J. Griffin, Regulatory Assurance - NRC Coordinator
M. McGivern, CCSW System Engineer
P. O'Connor, Lead License Operator Requalification Training
M. Otten, Corporate Training
B. Rybak, Acting Regulatory Assurance Manager
C. Symonds, Training Director

NRC personnel

M. Ring, Chief, Division of Reactor Projects, Branch 1

IEMA personnel

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000237/2006007-01	NCV	Failure to Identify an Inoperable 3-hour Fire Barrier Wall in the Unit 2 EDG Day Tank Room
05000237/2006007-02	NCV	Unit 2 350 psig Reactor Low Pressure Emergency Core Cooling System Permissive Switch Out-of-tolerance During Surveillance Testing
05000237/2006007-03	NCV	Failure to Post Protective Pathway Signs During Unavailability of Torus to Reactor Building Vacuum Breaker
05000249/2006007-04	NCV	Failure to Perform Procedure Steps in the Proper Sequence by Operations Caused Emergency Safety Feature Systems Actuation
05000237/2006007-05	FIN	Unit 2 High Pressure Coolant Injection (HPCI) System Declared Inoperable
05000237/2006007-06 05000249/2006007-06	NCV	Standby Liquid Control Valves Installed In The Plant Different than those Assumed in a Design Calculation

Closed

05000237/2006007-01	NCV	Failure to Identify an Inoperable 3-hour Fire Barrier Wall in the Unit 2 EDG Day Tank Room
05000237/2006007-02	NCV	Unit 2 350 psig Reactor Low Pressure Emergency Core Cooling System Permissive Switch Out-of-Tolerance During Surveillance Testing
05000237/2006007-03	NCV	Failure to Post Protective Pathway Signs During Unavailability of Torus to Reactor Building Vacuum Breaker
05000249/2006007-04	NCV	Failure to Perform Procedure Steps in the Proper Sequence by Operations Caused Emergency Safety Feature Systems Actuation
05000237/2006007-05	FIN	Unit 2 High Pressure Coolant Injection (HPCI) System Declared Inoperable
05000237/2006007-06 05000249/2006007-06	NCV	Standby Liquid Control Valves Installed In The Plant Different than those Assumed in a Design Calculation

05000237/97019-04 05000249/97019-04	URI	Concrete Expansion Anchor Safety Factor for High Energy Line Break (HELB) Whip Restraints
237/2006-002-00	LER	U2 Low Pressure Coolant Injection System Declared Inoperable

<u>Discussed</u>

None

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections or 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

-WO 00594962; D3 2Y Complete CCSW Pump Cubicle Cooler Performance Test
-DTS 1500-04 Revision 07; CCSW Pump Cubicle Coolers 2(3)-5700-30A&B and 30C&D Performance Test
-NRC Generic Letter 89-13, Service Water System Problems Affecting Safety Related Equipment
-EC 348504 Revision 00; Evaluate the Removal/Isolation of Two Cooling Tube Circuits of the 3-5700-30A Containment Cooling Service Water (CCSW) Room Cooler
-DOP 5750-21 Revision 21; Unit 2/3 Reactor Building Chilled Water System
-DOS 0010-24 Revision 08; Securing from Cold Weather Operations for Unit 2
-DOS 0010-27 Revision 06; Securing from Cold Weather Operations for Unit 3
-DOS 0010-21 Revision 11; Securing Cold Weather Operations for U1 & Out Buildings
-DOS 0010-33 Revision 09; Securing from Cold Weather Operations at the Lift Station, Goose Lake Pump Station, Security Diesel Building, and Cooling Towers
-CC-AA-309-1001 Revision 2; Calculation for CCSW Cooler Performance and Effectiveness Curve Essential Calc VV-13
-CC-AA-309-1001 Revision 2' Calculation for CCSW Cooler Performance and Effectiveness Curve Essential Calc VV-14
-IR 0049355 Enter DOA 5750-01 Due to Planned Work; May 25, 2005

1R04 Equipment Alignment

-DOP 2300-M1/E1; Revision 34; Unit 3 HPCI System Checklist
-DOS 0040-08; Revision 23; Unit 2 Operating Power Sources and Distribution
-DOP 6600-E2; Revision 05; Unit 2(3) Standby Diesel Generator
-DOP 5750-02; Revision 34; Reactor Building Ventilation

1R06 Flooding

-WO 00761944; D3 QTR TSTR CCSW Pump Vault Penetration Surveillance Testing; June 05, 2006
-WO 00679590; D3 18M Test CCSW Pump Vault Water Tight Door Leak Test
-DOS 1500-20; Unit 2(3) CCSW Pump Vault Penetration Surveillance Testing
-DOS 1500-21; Unit 2(3) CCSW Pump Vault Watertight Door Leak Test

1R11 Licensed Operator Requalification

-Dresden Station, Units 2 and 3 NRC Integrated Inspection Reports; dated various from July 28, 2004, through May 8, 2006
-TQ-AA-106; Licensed Operator Requal Training Program; Revision 7
-TQ-AA-210-5101; Training Observation Forms; dated various

-TQ-AA-301; Simulator Configuration Management; Revision 6
-TQ-AA-301-0301; Simulator SWR Prioritization, Maintenance, Modification, and Enhancements; Revision 2
-Curriculum Review Committee Meeting Minutes; dated various August 2004 through January 2006
-Training Advisory Committee Meeting Minutes; dated various June 2004 through February 2006
-List of SWRs Completed Past 12 Months; dated May 12, 2006
-List of Open SWRs; dated May 12, 2006
-Dresden 2005 Exam Summary
-Dresden 2006 Licensed Operator Requal Exam Results Summary; Weeks 1 and 2
-TQ-AA-106-0102; Licensed Operator Requal Training Classroom Attendance Sheets; Cycle 1, 2004 through Cycle 4; 2006
-2006 Dresden Sample Plan; LORT Exam Construction
-Dresden 2005 LORT Written Exams; Weeks 1 through 6
-Dresden 2006 LORT Operating Exam; Weeks 1, 2, and 3
-Dresden Operations Dept. Policy No. 62; Operations Department Standards and Expectations; dated March 3, 2006
-Simulator Malfunction Tests; dated various
-Simulator Transient Tests; dated various
-Simulator Steady State Tests; dated various
-Simulator Core Performance Tests; dated various
-Simulator Review Board Minutes; dated May 18, 2004; September 21, 2004; January 11, 2005; June 30, 2005; and October 25, 2005
-OP-AA-105-102; NRC Active License Maintenance; Revision 7
-Ten Licensed Operators' Medical Records; dated various
-TQ-AA-106-0102; Exelon Nuclear LORT Classroom Attendance; Revision 0
-TQ-AA-106-0113; Simulator Demonstration Examination Individual Competency Evaluation Forms; (Annual) Crew 1; dated May 17, 2006
-TQ-AA-106-0114; Simulator Demonstration Examination Crew Competency Evaluation Forms; (Annual) Crew 1, May 17, 2006
-TQ-AA-210-4101; Remedial Training Notification and Action on Failure; dated various
-TQ-AA-210-4102; Performance Review Committee Data Sheet; dated various
-TQ-AA-106-0304; Licensed Operator Requal Training Exam Development Job Aid; Revision 2
-TQ-AA-201; Examination Security and Administration; Revision 4
-IR 00334912; NOS Identifies Minor Exam Security Issue; dated May 13, 2005
-IR 00460014; Recommendations from LORT Pre-7111.11 FASA; dated February 28, 2006
-IR 00487168; Exam Security Issue During The Annual LORT Exam; dated May 6, 2006
-IR 00491450; NRC Identified Procedure Issue; dated May 18, 2006
-IR 00491455; NRC Identified - Simulator Testing Enhancements; dated May 18, 2006
-Issue Reports Initiated Based on NRC Observations

1R12 Maintenance Effectiveness

-IR 00473392; LPCI Maint Rule Function Z15-4 Availability Criteria Not Met; 3/31/06
-First Quarter 2006 LPCI Maintenance Rule Evaluation dated April 4, 2006, covering criteria Z15-4, Z15-5 and Z15-6.
-IR 00347372; Glycerin Puddle on D2 East LPCI Room Floor Due to Failed Gauge; 6/24/05
-IR 00394985; Relay Timing Out of Tolerance; 11/05/05
-IR 00368361; EQ Switches Not Torqued During 34Y Replacement; 8/30/05

1R13 Maintenance Risk Assessments and Emergent Work Control

-DOP 0500-03, Revision 29, Reactor Protection System Power Supply Operation

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

-IR 00475365; Rx Bldg Vent System Tripped and 2/3B SBGT Train Auto Started; April 5, 2006
-Apparent Cause Evaluation 475365

1R15 Operability Evaluations

-RSA-D-92-06, HPCI Room Thermal Response with Loss of HPCI Room Cooler, dated November 13, 1992
-CHRON #200889, Dresden Station Units 2 and 3, EQ Applicability Determination and Evaluation of Components Located in EQ Zones 4, 5 and 6 EQ Evaluation Transmittal 12-93-008

4OA2 Identification and Resolution of Problems

-IR 00316625; U2 Reactor, Group 1 Isolation and Scram; March 24, 2005
-IR 00317029; NOS ID'D EHC Scram Troubleshooting Discrepancies; March 25, 2005
-IR 00471092; Four "on duty" ERO members did not respond to pager test; March 27, 2006
-IR 00471096; Overall pager test contact rate below expectations; March 27, 2006
-IR 00476183; On-duty ERO non-responders to pager test; April 7, 2006
-IR 00481073; Dialogics pager system not receiving call-ins during pager test; April 20, 2006
-IR 00496221; ERO call-in pager test was a marginal pass; April 2, 2006
-IR 00454729; ERO Team member on call without an ERO pager; February 16, 2006
-IR 00455267; Dresden off-year exercise development process not followed; February 17, 2006
-IR 00439891; ERO pager test of 2/9/06 had 4 on-duty persons not respond; February 28, 2006

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
ARM	Area Radiation Monitor
Aux NSO	Auxiliary Nuclear Station Operator
CEA	Concrete Expansion Anchor
CFR	Code of Federal Regulations
CR	Condition Report
DFPP	Dresden Fire Protection Reports
DIS	Dresden Instrument Surveillance
DOP	Dresden operating Procedure
DOS	Dresden Operating Surveillance
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EHC	Electro Hydraulic Control
EP	Emergency Preparedness
EPRI	Electrical Power Research Institute
EOP	Emergency Operating Procedures
gpm	gallons per minute
HELB	High Energy Line Break
HER	HELB Pipe Whip Restraints
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilating and Air-Conditioning
IEMA	Illinois Emergency Management Agency
IFI	Inspection Followup Item
IMC	Inspection Manual Chapter
IR	Inspection / Issue Report
IST	Inservice Test
JPM	Job Performance Measure
LORT	License Operator Requalification Training
LPCI	Low Pressure Coolant Injection
MCC	motor control center
MG	motor generator
MOV	Motor Operated Valve
MWe	megawatts electrical
NCV	Non-Cited Violation
NFPA	National Fire Protection Association
NOS	Nuclear Oversight
NUREG	Nuclear Regulatory Guide
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PARS	Publicly Available Records
PI	Performance Indicator
PODM	Plan of the Day Meeting
RCIC	Reactor Core Isolation Cooling
RFP	Reactor Feed Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
SAT	Systems Approach to Training

SBLC	Standby Liquid Control
SDP	Significance Determination Process
SF	Safety Factor
SRO	Senior Reactor Operator
SW	Service Water
TIA	Task Interface Agreement
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
US	Unit Supervisor
WO	Work Order