July 29, 2005

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 05000237/2005008;
05000249/2005008

Dear Mr. Crane:

On June 30, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report presents the inspection findings which were discussed with Mr. D. Bost and other members of your staff on July 12, 2005.

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

Based on the results of this inspection, four NRC identified findings of very low safety significance were identified. Two of these findings involved a violation of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest any Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, 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.

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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 05000237/2005008; 05000249/2005008
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
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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Docket Nos: | 50-237; 50-249 |
| License Nos: | DPR-19; DPR-25 |
| Report No: | 05000237/2005008; 05000249/2005008 |
| Licensee: | Exelon Generation Company |
| Facility: | Dresden Nuclear Power Station, Units 2 and 3 |
| Location: | 6500 North Dresden Road<br>Morris, IL 60450 |
| Dates: | April 1 through June 30, 2005 |
| Inspectors: | D. Smith, Senior Resident Inspector<br>M. Sheikh, Resident Inspector<br>C. Phillips, Senior Operations Engineer<br>W. Slawinski, Senior Radiation Specialist<br>R. Winter, Reactor Engineer<br>L. Ramadan, Inspector, Region III<br>D. Melendez-Colon, Inspector, Region III<br>D. Reeser, Reactor Engineer<br>M. Gryglak, Reactor Inspector, Decommissioning Branch<br>R. Schulz, Illinois Emergency Management Agency |
| Approved by: | Mark Ring, Chief<br>Branch 1<br>Division of Reactor Projects |

Enclosure

## SUMMARY OF FINDINGS

IR 05000237/2005008; IR 05000249/2005008; 04/01/2005 - 06/30/2005; Exelon Generation Company, Dresden Nuclear Power Station, Units 2 and 3; Identification and Resolution of Problems, Event Follow-up, routine integrated report.

This report covers a 3-month period of baseline resident inspection; announced baseline inspections on radiation material processing and transportation, operator requalification program, maintenance rule effectiveness, and independent spent fuel storage installation activities. The inspection was conducted by Region III inspectors and the resident inspectors. Four Green findings, two of which involved 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 severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector Identified Findings

**Cornerstone: Barrier Integrity**

- Green. On February 8, 2005, a performance deficiency was identified by the inspectors. The licensee failed to identify the failure of the refuel floor damper in the reactor building ventilation system in a timely manner which resulted in the late discovery of a design deficiency with the standby gas treatment system. The standby gas treatment system used reactor building ventilation ductwork before directing air flow to the standby gas treatment filters. The refuel floor damper would throttle down, per design, to ensure a local negative differential pressure in the reactor water cleanup heat exchanger rooms with respect to the refuel floor. As a result, air flow to the standby gas treatment system was significantly restricted and affected the standby gas treatment recovery time for the entire secondary containment. The damper failed prior to 2003, masking the design deficiency, and was unnoticed until February 2005. Also, inadequate inspections of the dampers in the reactor building ventilation system during operation of the standby gas treatment system contributed to the late discovery of this design issue. The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution.

  The finding was greater than minor because, if left uncorrected, the failure to identify deficient plant equipment would become a more significant safety concern because important systems could be rendered inoperable and because it impacted the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. In addressing this issue, the licensee gagged each unit's refuel floor damper open to 80 percent to ensure adequate air flow to the standby gas treatment system. The finding was of very low safety significance because the standby gas treatment system was always able to restore secondary containment differential pressure within the Technical Specifications allowed outage time of four hours. (Section 4OA2.3)

- Green. On May 2, 2005, a performance deficiency was identified by the inspectors. The licensee failed to identify that corrective actions were ineffective from a previous 2004 event, involving the failure to follow the clearance order process. Also, an instrument maintenance technician failed to properly implement annual clearance order process training. As a result, the instrument maintenance technician removed the 2D traversing incore probe (TIP) drawer which had a clearance order danger tag attached to the control switch. The primary cause of this finding was related to the cross-cutting issues of human performance and problem identification and resolution.

  The finding was more than minor because, if left uncorrected, the licensee's failure to ensure plant personnel adherence to the clearance order process would become a more significant safety concern by resulting in significant personnel safety consequences, and because it impacted the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The removal and re-installation of the 2D traversing incore probe drawer did not adversely affect the ability to ensure containment isolation using the ball check containment isolation valve. The licensee briefed all maintenance personnel on this event and added more detailed discussion on the clearance order process to the annual site training. Therefore, this finding screened as having very low safety significance. (Section 4OA2.6)

**Cornerstone: Mitigating Systems**

- Green. On December 11, 2004, a performance deficiency involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI and Criterion III was identified by the inspectors. The licensee failed to perform post-modification testing and to assure critical aspects of the core spray modification installation, which included obtaining gap measurement for mechanical joints, verifying the capability of the tooling to produce the required surface finishes on pre-fabricated components, and verifying that the pre-fabricated components were properly machined, met the leakage analysis specifications.

  The finding was greater than minor because it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, specifically the design control attribute. The finding was of very low safety significance because the licensee was able to demonstrate, with the assistance of General Electric, that there was reasonable assurance that the modification was installed properly. The licensee planned to revise CC-AA-107, "Configuration Change Acceptance Testing Criteria," and/or CC-AA-107-1001, "Post Modification Acceptance Testing." The procedure change would provide that the substitution for post modification testing would ensure quality at least equivalent to that specified in the original design bases. In addition, the licensee planned to confirm that the installed core spray modification had been installed with a level of quality equivalent to the original design basis. (Section 4OA3.1)

- Green. On September 29, 2004, a performance deficiency involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified by the inspectors. The licensee had implemented inadequate corrective actions for a deficient condition that occurred on September 6, 1996, to prevent recurrence of a similar deficient condition that occurred on September 29, 2004. Both events involved the failure of safety related time delay relays to meet acceptance criteria due to the use of a stopwatch as a tool for calibration of safety related equipment. The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution.

The finding was greater than minor because it impacted the mitigating system cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events and because it affected the reliability of a safety related component. As a result of the 2004 event, the licensee initiated issue report 258172, created an action item to review the root cause of the event, revised the isolation condenser initiation time delay relay calibration procedure to require the use of a strip chart recorder, and created an action item to evaluate the extent of condition. The finding was of very low safety significance because the isolation condenser system did not lose the ability to perform its safety function and all other mitigating systems were available. (Section 4OA3.3)

B. Licensee Identified Findings

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 28, 2005, the unit was taken off line for main generator hydrogen seal maintenance. The unit returned to full power on June 2, 2005.
- On June 3, 2005, the unit downpowered to 767 MWe for control rod pattern adjustment, and returned to full power on the same day.

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

- On April 26, 2005, the unit was taken offline to replace the 3B reactor recirculation pump seal. The unit returned to full power on May 1, 2005.
- On May 8, 2005, the unit downpowered to 773 MWe for control rod pattern adjustment, and returned to full power on the same day.
- On June 2, 2005, the unit downpowered to 150 MWe due to a electro-hydraulic control system oil leak in the turbine front standard. The unit returned to full power on June 4, 2005.
- On June 16, 2005, the unit downpowered to 815 MWe due to an unexpected isolation of a feedwater heater string, and returned to full power on the same day.

### 1. REACTOR SAFETY

**Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity**

1R04 Equipment Alignment (71111.04Q and S)

.1 Partial System Walkdowns

a. Inspection Scope

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

The inspectors performed partial equipment alignment walkdowns of the:

- Unit 2/3 A train standby gas treatment system;
- Unit 3 B train core spray system;
- Unit 2 Division I direct current system and Unit 3 Division II direct current system; and
- Unit 2 A train core spray system.

This represented four inspection samples.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors performed a complete semiannual walkdown of the Unit 3 containment cooling service water system to verify proper alignment, component accessibility, availability, and current condition. The inspectors reviewed selected system operating procedures, surveillance procedures, mechanical and electrical lineups, drawings, and the Updated Final Safety Analysis Report (UFSAR) to identify proper system alignment. The inspectors reviewed outstanding work orders associated with the system to determine whether there were any deficiencies that could affect the ability of the system to perform its safety related function. The inspectors also reviewed selected licensee condition reports (CR) and issue reports (IR) to verify the effectiveness of completed corrective actions of past issues.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

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. The review included control of transient combustibles and ignition sources, fire suppression systems, manual fire fighting equipment and capability, passive fire protection features, including fire doors, and compensatory measures. The following areas were walked down:

- Unit 2 reactor building, elevation 476'-6" west low pressure coolant injection corner room, Fire Zone 11.2.1;

- Unit 2/3 emergency swing diesel generator building, elevation 517' of the emergency diesel generator room, Fire Zone 9.0.C;
- Unit 2/3 turbine building, elevation 534' switchgear area, Fire Zone 8.2.6.A;
- Unit 2 reactor building, elevation 476' 6" torus basement, Fire Zone 1.1.1.1;
- Unit 3 turbine building, elevation 517' switchgear area, Fire Zone 8.2.5.E;
- Unit 2 turbine building, elevation 517' emergency diesel generator room, Fire Zone 9.0.A; and
- Unit 2 turbine building, elevation 517' trackway, Fire Zone 8.2.5.A.

This represented seven inspection samples.

b. Findings

No findings of significance were identified.

1R06 Flooding (71111.06)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report (USFAR) Section 3.4.1.2 for internal flood analysis and reviewed the licensee's procedure for internal flooding. The inspectors walked down the Unit 2/3 cribhouse to verify compliance with the licensee's UFSAR and reviewed the licensee's previously implemented corrective actions for deficiencies associated with internal flood protection.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11A and Q)

.1 Annual Operating Test Results

a. Inspection Scope

The inspectors reviewed the overall pass/fail results of the annual operating examination which consisted of Job Performance Measure operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from May 3 through June 1, 2005. In addition, the inspectors reviewed the overall pass/fail results for the biennial written examination (also required to be given per 10 CFR 55.59(a)(2)) administered by the licensee from May 4 through June 10, 2005. The overall results were compared with the significance determination process in accordance with NRC Manual Chapter 0609, "Operator Requalification Human Performance Significance Determination Process."

This represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Licensed Operator Requalification Program

a. Inspection Scope

The inspectors observed an evaluation of operating crew #3 on June 1, 2005. The scenario consisted of a loss of instrument air (recoverable), loss of motor control center 28-7/29-7, and a recirculation line break resulting in containment flooding. The inspectors verified that the operators were able to complete the tasks in accordance with applicable plant procedures. The inspectors observed the licensee's evaluators to ensure that no inappropriate cues were provided by the evaluators while assessing the operators' performance. In addition, the inspectors verified that issue reports written regarding licensed operator requalification training were entered into the licensee's corrective action program with the appropriate significance characterization.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12B and Q)

.1 Periodic Evaluation

a. Inspection Scope

The inspectors examined the periodic evaluation report completed for the period of October 1, 2002 through September 30, 2004. To evaluate the effectiveness of (a)(1) and (a)(2) activities, the inspectors examined a sample of Dresden (a)(1) Action Plans, performance criteria, functional failures, and issue reports. These same documents were reviewed to verify that the threshold for identification of problems was at an appropriate level and the associated corrective actions were appropriate. Also, the inspectors reviewed the maintenance rule procedures and processes. The inspectors focused the inspection on the following four systems (samples):

- Direct current electric system;
- High pressure core injection system (HPCI);
- Containment cooling service water system (CCSW); and
- Hardened containment vent system.

The inspectors verified that the periodic evaluation was completed within the time restraints defined in 10 CFR 50.65 (once per refueling cycle, not to exceed 24 months). The inspectors also ensured that the licensee reviewed its goals, monitored structures, systems, and components (SSCs) performance, reviewed industry operating experience, and made appropriate adjustments to the maintenance rule program as a result of the above activities;

The inspectors verified that the licensee balanced reliability and unavailability during the previous refueling cycle, including a review of high safety significant SSCs;

The inspectors verified that (a)(1) goals were met, that corrective action was appropriate to correct the defective condition, including the use of industry operating experience, and that (a)(1) activities and related goals were adjusted as needed; and

The inspectors verified that the licensee has established (a)(2) performance criteria, examined any SSCs that failed to meet their performance criteria, and reviewed any SSCs that have suffered repeated maintenance preventable functional failures including a verification that failed SSCs were considered for (a)(1).

In addition, the inspectors reviewed maintenance rule self-assessments that addressed the maintenance rule program implementation.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Routine Inspection

a. Inspection Scope

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the selected systems. 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 inspectors identified issue or problem that potentially impacted system work practices, reliability, or common cause failures:

- Unit 2 emergency diesel generator system; and
- Unit 3 miscellaneous sumps and drains 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 two inspection samples.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors evaluated the effectiveness of the risk assessments performed before maintenance activities were conducted on structures, systems, and components and verified how the licensee managed the risk. The inspectors evaluated whether the licensee had taken the necessary steps to plan and control emergent work activities. The inspectors also verified that equipment necessary to complete planned contingency actions was staged and available. The inspectors completed evaluations of maintenance activities on the:

- Unit 2 maximum combined flow limiter setting adjustment;
- Unit 3 Division 1 core spray logic system functional testing;
- Unit 2 Division 1 low pressure coolant injection containment cooling water logic system functional testing;
- Unit 3 125 Vdc battery charger #3 removal from service; and
- Unit 2 and Unit 3 concurrent performance of surveillances associated with the core spray system, high pressure coolant injection system, and standby liquid control system.

This represented five inspection samples.

b. Findings

No findings of significance were identified.

## 1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed operability evaluations to ensure that operability was properly justified and the component or system remained available, such that no unrecognized increase in risk occurred. The review included issues involving the operability of:

- Unit 2 B service water pump did not trip (IR 324995);
- Unit 2/3 time for standby gas treatment system to recover reactor building differential pressure abnormally long (IR 320258); and
- Unit 2 isolation condenser steam supply vent lines (engineering changes 352592 and 353273).

This represented three inspection samples.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Around (71111.16)

Semi-annual Review of the Cumulative Effects of Operator Workarounds

a. Inspection Scope

The inspectors reviewed all operator workarounds and challenges to assess any cumulative effect on the :

- reliability, availability, and potential for misoperation of a system;
- multiple mitigating systems; and
- ability of operators to respond in a correct and timely manner to plant transients and accidents.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Unit 3 containment cooling service water scupper drain check valve, 3-4999-75 inspection;
- Unit 2/3 emergency diesel generator cooling water pump replacement;
- Unit 2/3 emergency diesel generator power packs replacement, installation of flex house, replacement of 2/3 diesel generator coolant water pump with stainless steel design; and
- Unit 2 B service water pump breaker trip coil replacement.

This represented four inspection samples.

b. Findings

.1 Inability to Trip the 2B Service Water Pump from the Control Room

Introduction: The inspectors identified an unresolved item regarding the adequacy of installation of sixteen trip coil mechanisms for breakers on Unit 2 safety related 4KV buses 23 and 24.

Description: On April 15, 2005, while swapping service water (SW) pumps, the onshift operator started the 2A SW pump and then attempted to secure the 2B SW pump by placing the control switch in the normal-after-trip position. However, the pump did not trip as indicated by the motor amperage reading, and the light indication for the pump did not illuminate. Subsequently, the onshift operator placed the control switch in the pull-to-lock position, but the 2B SW pump continued to run. A non-licensed operator was dispatched locally to bus 24 and tripped the pump with the local trip pushbutton on the breaker.

On April 20, 2005, the licensee informed the residents that the tripping capability of the 2B SW water pump was lost due to the incorrect installation of the pump's trip coil mechanism. Initially, the licensee considered this installation error to be generic in nature and to have existed since 1995. The inability to trip the 2B SW pump was of concern because bus 24 could be lost due to the inability to shed this load from the bus during an accident. This bus was the power supply source for the Division II containment cooling service water system pumps.

Subsequently, the licensee determined that the 2B SW pump was worked on February 15, 2005, under Work Order (WO) 00727085-01. The work was to clean and inspect the close latch reset mechanism on the breaker for hardened lubricant. The WO included the appropriate information from the vendor manual on how to perform the work; however, the electrician installed the trip coil incorrectly. The WO provided an optional instructional step for post-maintenance testing, which specified verification of the electrical operation of the breaker. Because this step was not required to be performed, the post maintenance test did not identify that the 2B SW pump would not trip from the control room after the incorrect installation of the trip coil mechanism. The licensee proceeded with inspecting the installation of the trip coil mechanisms for all the potentially affected breakers even though the licensee suspected that the inadequate work on the 2B SW pump was an isolated case of poor human performance.

The licensee performed inspections of all the applicable Unit 3 breakers during the April 2005 forced outage. The inspections confirmed that all trip coils had been properly installed. Initially, the licensee was able to verify proper installation of the trip coils for several breakers on Unit 2 that had their associated breaker opened since the equipment was not in service. Four more breakers were inspected, with satisfactory results, during the 2005 May maintenance outage. The remaining 16 breakers will be inspected during the Fall 2005 refueling outage because the licensee was concerned that the inspection activity, which involved the removal of the breaker cover, could adversely impact plant operations. This issue will be an Unresolved Item (URI) pending inspector review of the results of the inspections on the remaining breakers.
(URI 05000237/2005008-01)

1R20 Outage Activities (71111.20)

.1 Unit 3 Maintenance Outage

a. Inspection Scope

The licensee conducted a maintenance outage on Unit 3 from April 26-May 1, 2005. During the outage the licensee replaced the 3B reactor recirculation pump seal, repaired the 3B master trip solenoid valve, replaced the 3E electromatic relief valve, and assessed the condition of the strain gauges on the main steam lines and made appropriate repairs.

The inspectors verified that the licensee effectively conducted the shutdown, managed elements of risk pertaining to reactivity control during and after the shutdown, and implemented decay heat removal system procedure requirements as applicable. The inspectors performed the following activities daily:

- attended control room operator and outage management turnover meetings to verify that the current shutdown risk status was well understood and communicated;
- performed walkdowns of containment to identify any indications of unidentified leakage;
- ensured that the control room operators adhered to the plant’s Technical Specifications;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- reviewed selected issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance;
- ensured that the licensee appropriately considered risk factors during the development and execution of planned activities;
- monitored licensee’s troubleshooting efforts for emergent plant equipment issues;
- performed plant walkdowns to observe ongoing work activities;
- observed control rod withdrawals and initial transition to criticality;
- performed walkdown of containment prior to closure to ensure that debris had not been left that could affect the performance of the containment sumps; and
- monitored Mode switch changes and observed portions of power ascension.

b. Findings

No findings of significance were identified.

.2 Unit 2 Maintenance Outage

a. Inspection Scope

On May 28, 2005, the licensee commenced a four day maintenance outage on Unit 2 to replace the #10 main turbine generator seal. During the outage, the reactor remained critical at approximately 20 percent power. The licensee replaced the 2A stator cooling water pump, calibrated the bus duct temperature alarms, and repaired the turbine generator thrust bearing wear detector.

The inspectors verified that the licensee effectively removed the turbine from service, conducted the downpower, and managed elements of risk pertaining to reactivity control during and after the downpower.

The inspectors performed the following activities daily:

- attended control room operator and outage management turnover meetings to verify that the current online risk status was well understood and communicated;
- ensured that the control room operators adhered to the plant's technical specifications;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- reviewed selected issues that the licensee entered into the corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance;
- ensured that the licensee appropriately considered risk factors during the development and execution of planned activities;
- monitored licensee troubleshooting efforts for emergent plant equipment issues; and
- performed plant walkdowns to observe ongoing work activities.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

The 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:

- Dresden Operating Surveillance (DOS) 1600-29, "Unit 2 and 3 Drywell Temperature Surveillance," Revision 4
- MA-DR-773-733, "Unit 3 - Calibration and Functional Test of RPS MG Set and RPS Reserve Power Supply EPAs," Revision 2;

- Dresden Instrument Surveillance (DIS) 1400-05, "Division 1 Core Spray System Functional Test," Revision 26;
- DIS 1400-05, "Division 2 Core Spray System Functional Test," Revision 26;
- DIS 1500-27, "Division 1 Low Pressure Coolant Injection Containment Cooling Logic System Functional Test," Revision 5;
- Unit 2(3), Appendix A, "Reactor Coolant System Leakage," Revision 98; and
- DOS 6620-07, "Station Black Out 2 (3) Diesel Generator Surveillance Tests," Revision 18.

This represented seven inspection samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Modification (71111.23)

a. Inspection Scope

The inspectors screened one active temporary modification and assessed the effect of the temporary modification on safety-related systems. The inspectors also determined if the installation was consistent with system design:

- Temporary Change Configuration Package 354622, "Install Temporary Jumper at Electro Hydraulic Control System Card 2-5640-A37 (in Cabinet 2-0902-31) to Bypass the Function of "A" Main Steam Pressure Regulator."

This represented one inspection sample.

b. Findings

No findings of significance were identified.

1EP6 Drill and Training Evaluation (71114.06)

.1 Evaluation of Operating Crew #6 Training Evolution

a. Inspection Scope

The inspectors evaluated the training evolution to assess the licensee's performance and to determine if the training was of the appropriate scope to be included in the performance indicator statistics. The inspectors observed Crew #6 on May 11, 2005. The scenario consisted of spurious isolation of high pressure coolant injection system, control rod drive system leak and accumulator trouble, anticipated transient without scram, and reactor building high radiation.

This represented one inspection sample.

b. Findings

No findings of significance were identified.

## 2. RADIATION SAFETY

**Cornerstone: Public Radiation Safety**

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the licensee's current revision to the Offsite Dose Calculation Manual (ODCM) and the licensee's Radioactive Effluent Release Reports for calendar years 2002, 2003, and 2004, along with selected radioactive effluent release data for 2005 through April 2005. The inspectors verified that technical evaluations were completed for modifications to the ODCM since the last inspection of this program area in 2003, and that effluent radiation monitor setpoints were changed accordingly since completion of those modifications, as warranted. The inspectors also reviewed self-assessments, audits, and licensee event reports that involved unanticipated offsite releases of radioactive effluents, as applicable. The effluent reports, effluent data, and licensee evaluations were reviewed to verify that the radioactive effluent control program was implemented as required by the radiological effluent technical specifications (RETS) and the ODCM, to verify that public dose limits from effluents were not exceeded, and to ensure that any anomalies in effluent release data were adequately understood by the licensee and were properly assessed and reported.

The inspectors reviewed the ODCM to identify the gaseous and liquid effluent radiation monitoring systems and associated effluent flow paths including in-line flow measurement devices, and reviewed the description of radioactive waste systems and effluent pathways provided in the UFSAR in preparation for the onsite inspection.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.2 Onsite Inspection - Walkdown of Effluent Control Systems, System/Program Modifications, and Instrument Calibrations

a. Inspection Scope

The inspectors walked down the readily accessible components of the gaseous and liquid release systems (e.g., radiation and flow monitors, tanks, and vessels) and the radwaste control room to observe current system configuration with respect to the description in the UFSAR, to discuss ongoing activities with radwaste operations staff, and to assess equipment material condition. Records of material condition surveillances performed since 2004 for those tanks and vessels located in locked high radiation areas were reviewed to determine the extent of any problems and the licensee's corrective actions.

The inspectors reviewed the technical justification for any changes made by the licensee to the ODCM, as well as changes to the liquid or gaseous radioactive waste system design or operation since the last inspection to determine whether these changes affected the licensee's ability to maintain effluents as low as reasonably achievable and whether changes made to monitoring instrumentation resulted in non-representative monitoring of effluents. Radioactive effluent release reports for the three years preceding the inspection were evaluated for any significant changes (factor of 5) in either the quantities or kinds of radioactive effluents and for any significant changes in offsite dose which could be indicative of problems with the effluent control program. No significant adverse changes were identified.

The inspectors reviewed records of the most recent instrument calibrations for each point-of-discharge effluent radiation monitor and for selected effluent flow measurement devices to determine if they had been calibrated consistent with industry standards and in accordance with station procedures, technical specifications and the ODCM. Specifically, the inspectors reviewed calibration records for the following effluent radiation monitors and flow measuring devices:

- Unit 2/3 reactor building vent (station particulate, iodine and noble gas (SPING)) monitor;
- Unit 2/3 main chimney (backup) noble gas monitor;
- Unit 2/3 main chimney SPING monitor;
- Unit 2 and Unit 3 service water effluent gross activity monitors;
- Unit 2/3 liquid radwaste effluent gross activity monitor;
- Unit 2 and Unit 3 isolation condenser vent radiation monitors;
- Unit 2/3 main chimney flow rate monitoring device; and
- Unit 2/3 reactor building vent flow rate monitoring device.

The inspectors also reviewed effluent radiation monitor setpoint bases and alarm setpoint values for these monitors to verify their technical adequacy and for compliance with ODCM criteria. Additionally, the inspectors discussed with system engineering staff the availability and performance of the above listed effluent monitors and discussed the corrective actions underway to address historical problems with the service water monitors.

The inspectors reviewed chemistry department quality control data for those instrumentation systems used to quantify effluent releases. Specifically, the inspectors reviewed the most recent efficiency calibration records and lower limit of detection determinations for Chemistry Department gamma spectroscopy systems and for the liquid scintillation counter.

These reviews represented three inspection samples.

b. Findings

No findings of significance were identified.

.3 Onsite Inspection - Effluent Release Packages, Abnormal Releases, Dose Calculations, and Laboratory Analytical Quality Control

a. Inspection Scope

The inspectors selectively reviewed batch liquid effluent release packages and gaseous effluent sampling data for selected periods in 2004 through April 2005, including results of chemistry sample analyses, the application of vendor laboratory analysis results for difficult to detect nuclides, and the licensee's effluent release procedures and practices. Additionally, the inspectors reviewed the methods for calculating the projected doses to members of the public from these releases. These reviews were performed to verify that the licensee adequately applied analysis results in its dose calculations consistent with ODCM methodology, and to determine if effluents were released in accordance with the RETS/ODCM and procedural requirements.

The inspectors accompanied chemistry staff to observe the routine weekly change-out of the particulate and iodine samplers and the collection of a noble gas sample from the Unit 2/3 main chimney to determine if sampling practices, sampler restoration and analytical techniques were sound and consistent with procedure.

The inspectors reviewed records of abnormal/unmonitored releases that the licensee identified and documented in its 2003 and 2004 annual effluent reports and discussed the methods used to quantify these releases. The inspectors also reviewed the licensee's practices for compensatory sampling during periods of effluent monitor inoperability to verify compliance with ODCM requirements.

The inspectors reviewed a selection of quarterly and annual dose calculations to ensure that the licensee properly calculated the offsite dose from radiological effluent releases and to determine if any annual RETS/ODCM (i.e., Appendix I to 10 CFR Part 50) design objectives (limits) were exceeded.

The inspectors reviewed the results of the quarterly radiochemistry inter-laboratory cross-check comparisons for the five calendar quarters preceding the inspection to validate the licensee's analyses capabilities. The inspectors reviewed the licensee's evaluation of any disparate inter-laboratory comparisons and the associated corrective actions for any deficiencies identified, as applicable. In addition, the inspectors reviewed the results of the licensee's 2003 and 2004 quality assurance audits of the RETS/ODCM program.

These reviews represented four inspection samples.

b. Findings

No findings of significance were identified.

.4 Air Cleaning System Surveillance Tests

a. Inspection Scope

The inspectors reviewed the most recent results for both trains of the Unit 2/3 standby gas treatment (SBGT) system ventilation system filter testing to verify that test methods, frequency, and test results met technical specification requirements. Specifically, the inspectors reviewed the results of in-place high efficiency particulate air (HEPA) and charcoal absorber penetration tests, laboratory tests of charcoal absorber methyl iodide penetration and in-place tests of pressure differential across the combined HEPA filters/charcoal absorbers for the SBGT.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed licensee self-assessments, audits, and special reports related to the radioactive effluent treatment and monitoring program since the last inspection to determine if identified problems were entered into the corrective action program for resolution. The inspectors also verified that the licensee's problem identification and resolution program together with its audit and self-assessment program were capable of identifying repetitive deficiencies or significant individual deficiencies in problem identification and resolution.

The inspectors reviewed various corrective action reports related to the radioactive effluent treatment and monitoring program generated since 2004, interviewed staff, and reviewed documents to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions; and
- Implementation/consideration of risk significant operational experience feedback.

These reviews represented one inspection sample.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

**Cornerstone: Public Radiation Safety**

.1 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's submittals for the performance indicator (PI) listed below for the period indicated. The inspectors used PI definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the PI data. The following PI was reviewed:

- Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrence.

The inspectors reviewed the licensee's CR database and selected CRs generated since this indicator was last reviewed in June 2004, to identify any potential occurrences such as unmonitored, uncontrolled, or improperly calculated effluent releases that may have significantly impacted offsite dose. The inspectors reviewed gaseous and liquid effluent summary data and the results of associated offsite dose calculations for 2004 to determine if indicator results were accurately reported. Additionally, the inspectors discussed with chemistry staff its methods for quantifying effluents and determining effluent dose.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Quarterly Review

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are generally denoted in the report. In addition, in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing daily issue reports and attending daily issue report review meetings.

b. Findings

No findings of significance were identified.

.2 Semiannual Review for Trends

a. Inspection Scope

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” 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 six month period from January 2005 through June 2005, 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 of January through June 2005, 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 technical specifications. 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 removed groups of IRs that discussed security issues, those will be reviewed and documented as necessary in a separate report during a future inspection by a security specialist;

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

6. The inspectors obtained a list of all licensee common cause investigations initiated in the last six months. All IRs in which the title indicated a trend or potential adverse trend were considered licensee-identified trends;

7. 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

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

9. 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 to June of 2005.

This represented one inspection sample.

b. Findings

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

.3 Secondary Containment Differential Pressure (dP)

a. Inspection Scope

The inspectors reviewed issue reports associated with the loss of secondary containment dP and the inability to maintain secondary containment dP at the required Technical Specifications (TS) value of -0.25 inch dP when starting one train of the SBGT system either automatically or manually.

This represented one inspection sample.

b. Findings

Introduction: A Green finding was identified by the inspectors involving the licensee's failure to identify the failure of a damper in the reactor building ventilation system in a timely manner, and the licensee's failure to identify a design deficiency during operation of the SBGT system. The licensee identified the damper failure on February 8, 2005. However, the damper had been in a failed open condition since 2003. The failed open damper allowed significant additional air flow and masked a design deficiency with air flow to the SBGT system. The amount of air flow to the SBGT system was significantly restricted when the failed damper was repaired, which delayed the ability of the SBGT system to restore secondary containment dP to -0.25 inch.

Description: The inspectors reviewed the control room logs and determined that there were eight occasions between January 14, 2005 and May 20, 2005, where there were problems with the SBGT system maintaining secondary containment to -0.25 inch dP. During the first six instances, one train of the SBGT system was able to restore secondary containment dP to -0.25 inch within 5 to 15 minutes. Other variables which contributed to the normal recovery times of 5 to 15 minutes included wind speed, and the resultant 28 square foot opening in secondary containment that existed until the reactor building ventilation isolation valves closed due to the delay time between manually securing reactor building ventilation fans and closing the reactor building ventilation isolation valves.

On April 1, 2005, the seventh occurrence, after manually starting one train of the SBGT system and manually isolating the reactor building ventilation system, secondary containment was not restored to -0.25 inch dP until 56 minutes later. On May 20, 2005, the SBGT system automatically started when a refueling floor radiation monitor failed high. Secondary containment was not recovered to -0.25 inch dP until 12 minutes and had reached a positive value for approximately one minute. In addition to this occurrence where secondary containment went positive, the licensee determined that there were 51 other times when secondary containment went positive between July 26, 2001 and January 24, 2005.

As a result of the April 1, 2005 event, the inspectors challenged the acceptability of reactor building ventilation and SBGT performance with respect to the time required to restore secondary containment to -0.25 inch dP. The licensee conducted an investigation into the April 1, 2005 event. The licensee documented in apparent cause evaluation 320358 that the excessive 56 minute recovery time was due to an inadequate design, which had existed since original plant operation, and inadequate inspections of the reactor building ventilation system.

The SBGT system was designed to maintain Unit 2 and 3 secondary containment at -0.25 inch dP by using reactor building ductwork and controls to ensure all radioactive particles were processed through the SBGT system before releasing to the environment. The reactor building ventilation system has a significantly higher flow rate than the SBGT system. This flow rate difference between the systems was the reason why the restricted air flow affected the SBGT system and not the reactor building ventilation system. One dP controller, #2-5703-15, controlled 14 dampers, including the refuel floor damper on each unit, #2/3-5772-58. The operation of the SBGT system was adversely affected by the operation of this dP controller when the refuel floor damper was operating correctly. The dP controller controlled area dP control dampers to ensure the regenerative and non-regenerative heat exchanger rooms were maintained at a negative pressure relative to the refuel floor. If a negative dP was not maintained between these rooms and the refuel floor, dP controller #2-5703-15 would throttle down all 14 area control dampers and force air to be drawn from these two heat exchanger rooms. Since the SBGT system used the reactor building ventilation ductwork prior to directing flow to the SBGT system, the throttling down response of the 14 area control dampers restricted the air flow available to the SBGT system and delayed the system's ability to restore the entire secondary containment to -0.25 inch dP.

Refuel floor damper #2-5772-58, had failed full open and remained in this position from 2003 until February 8, 2005 and masked the air flow restriction problem to the SBGT system. As a result of this damper failing open, when dP controller #2-5703-15 sent signals to all 14 dampers to throttle down, the SGBT system was able to draw a significant amount of flow through this damper from the refueling floor and restore secondary containment to -0.25 inch dP much sooner. After damper #2-5772-58 was repaired on March 14, 2005, and capable of throttling down, the SBGT system would experience excessive recovery times in restoring secondary containment based on the severely restricted air flow to the SBGT system. The overall result was that the ability of the SBGT system to restore total secondary containment was negatively impacted based on the design of dP controller #2-5703-15. The inspectors determined and the licensee agreed that there was a lack of sensitivity toward the loss of secondary containment as supported by the 52 times that secondary containment went positive. The licensee addressed this design deficiency by gagging the refuel floor damper on each unit open by 80 percent. This action ensured adequate air flow to the SBGT system and thus would allow timely restoration of secondary containment.

Analysis: The inspectors determined that the licensee's failure to identify the failure of refuel floor damper #2-5772-58 in a timely manner, which delayed the licensee's discovery of a design deficiency with the SBGT system, 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 May 19, 2005. The inspectors concluded that the finding, if left uncorrected, would become a more significant safety concern by potentially rendering safety related equipment inoperable and because it impacted the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The flow to the SBGT system was significantly restricted when damper #2-5772-58 operated as designed. The restricted air flow delayed the ability of the SBGT system to restore secondary containment to -0.25 inch dP. Although the SGBT system was adversely impacted by the refuel floor damper, the SBGT system always restored secondary containment within the four hour TS allowed outage time. The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Appendix A, Attachment 1, dated December 1, 2004. The inspectors concluded that the finding impacted the barrier integrity cornerstone. The inspectors answered 'Yes' to question 1 under the containment barrier cornerstone column, in that, the finding only affected the SBGT and reactor building ventilation systems. Therefore, this finding is of very low safety significance (Green).

Enforcement: No violations of NRC requirements occurred because the finding involved the reactor building ventilation system which is a non-safety related system. The licensee entered this issue into the station's corrective action program as IR 320258. The licensee implemented several corrective actions which included immediately gagging open the refuel floor damper on each unit. The licensee subsequently changed the set point of the differential pressure controller which would throttle the 14 dampers less and thus ensure the restoration of secondary containment in a more timely manner. (Finding (FIN) 05000237/2005008-02; 05000249/2005008-02)

.4 Unit 2/3 Cribhouse Sump Pump Failure

The inspectors reviewed IR 331423. On May 3, 2005, the licensee entered Dresden Operating Abnormal Procedure (DOA) 40-02, "Localized flooding in plant," Revision 15, due to the accumulation of 6 - 8" of water in the 2/3 cribhouse. The flooding occurred due to the failure of the sump pumps' limit switches which prevented the sump pumps from starting on a high water level condition in the sump. The inspectors identified that the licensee failed to repair the 2/3 cribhouse sump pumps' level switches, in accordance with the work control process, when the switches failed in February 2005.

This represented one inspection sample.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed IR 331423 and the associated investigation report to verify that the licensee's identification of the problems were 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 reviewed IR 331423 and the associated investigation report. The inspectors considered the licensee's evaluation and disposition of performance issues, and application of risk insights for prioritization of issues.

(2) Issues

The inspectors interviewed station personnel and reviewed the appropriate WO for the issue. The inspectors noted that in February 2005, the 2/3 cribhouse sump was about to overflow due to the failure of the sump pump's level switches. A facility type WO was initiated in February to repair the level switches and was prioritized as a B3 ticket. Per work control procedure WC-AA-106, "Work screening and processing," Revision 2, B3 type work was supposed to be performed within five weeks.

The WO was initially on hold due to a request for parts; however, the work was not completed even after the part arrived on March 1, 2005. The inspectors questioned the lack of timely corrective actions for repairing the level switches, which were not completed until May 2005. The licensee indicated that the untimely repair of the level switches was because the work was assigned to the Fix It Now team. Due to emergent work and maintenance outages which added to the team's backlog, the Fix It Now team did not work this WO within the five week period. As a result of the licensee's failure to resolve the deficiency with the sump pumps' level switches in February 2005, the switches failed again and flooded the 2/3 cribhouse in May 2005. At that time, the licensee initiated aggressive actions to repair the level switches. If the licensee had repaired the switches in a more timely manner, reccurrence of the sump pumps' failure to run would not have occurred and caused the flooding in the cribhouse. The licensee initiated IR 337135 to address the inspectors' concerns. In addition, the licensee implemented actions to address weaknesses in prioritizing the Fix It Now team's WO backlog.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the corrective actions which resulted from the investigation report associated with IR 331423 to determine if the issue report addressed generic implications and that corrective actions were appropriately focused to correct the problem.

(2) Issues

There were no issues in the area of Effectiveness of Corrective Actions.

.5 Corrective Action Program

Introduction

The inspectors identified several examples where the licensee failed to properly implement the various aspects of the station's CAP during this period. During the first quarter 2005 and the fourth quarter of 2004, the licensee experienced problems with writing issue reports. Initially, the inspectors planned to document this problem in the first quarter inspection report; but, instead discussed this problem as an observation during the quarterly exit meeting on April 15, 2005.

Additional examples of this problem ,as well as other deficient implementation aspects of the station's CAP, continued to occur and included the lack of appropriate challenge of documented information in issue reports, inappropriate closure of issue reports by the site ownership committee (SOC) and management review committee(MRC), and the failure of shift managers to document the operability basis when issue reports documented known deficient plant conditions.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed all the IRs and the associated immediate followup actions to verify that the licensee's identification of the problems was complete and accurate, and that the consideration of extent of condition review, generic implications, and common cause was adequate.

(2) Issues

Generally, the licensee identified deficient plant conditions but did not always enter the items into the station's CAP. The licensee failed to generate five issue reports, until prompted the inspectors. The issues were minor in nature. The licensee subsequently generated the following Irs: 321457(Delay in Reset of TIP Group 2 Isolation from Partial

Group 2 Isolation), 333251(Ultrasonic Flow Meter for U2 Hydrogen Seal Oil Flow), 325867 (PPE Exemption Form not Properly Displayed), 345612 (Unit 2 SW Rad Monitor Spike), and 338026 (Received Unexpected H2 Area Trouble Alarm).

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

Generally the license prioritized and evaluated the issues. However, there were several examples where either the shift manager failed to document the basis for operability for deficient plant equipment or the site ownership and management review committees did not challenge the absence of operability information or other information which ensured effectiveness of the corrective action process. The oversight by the (CAP) committees and the shift managers did not result in the inoperability of any equipment. The licensee subsequently generated IRs 343019 (Operator Struck in Head by Falling Light Diffuser), 333408 (NRC Identifies Valve Locking Chain on Cable Tray Support), and 327336 (NRC Questions Actions Taken in SOC and MRC Closure of IRs).

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The inspectors reviewed the corrective actions for the associated IRs to determine if the issue reports addressed generic implications and that corrective actions were appropriately focused to correct the problem.

(2) Issues

The licensee continued to experience problems with initiating IRs without being prompted by the inspectors. The site ownership and management review committees had several instances where both groups were not effective in ensuring the appropriate actions were taken by the station for documented plant deficiencies. Also, the shift managers had not been consistently documenting the basis for why equipment remained operable when deficiencies were identified with equipment.

This represented one inspection sample.

.6 Removal of the 2D Traversing Incore Probe Drawer While Clearance Order Danger Tag Was Attached to Equipment

a. Inspection Scope

The inspectors reviewed the licensee's followup actions to a clearance order event on May 2, 2005. The inspectors interviewed several maintenance supervisors and reviewed associated documentation for this event.

This represented one inspection sample.

b. Findings

Introduction: A Green finding was identified by the inspectors. The licensee failed to identify that corrective actions were ineffective from a previous 2004 event involving the failure to follow the clearance order process. Also, an instrument maintenance technician failed to properly implement annual clearance order process training. As a result, the instrument maintenance technician removed the 2D TIP drawer while it was tagged out-of-service with a danger tag.

Description: On May 2, 2005, instrument maintenance (IM) technicians were assigned to perform WO 692871-01 which was a two year preventive maintenance task on the 2D TIP drawer. Operations personnel had placed clearance order #35879 to allow the performance of other work associated with the system; a clearance order danger tag was placed on the control switch of the 2D TIP drawer. During the pre-job brief, the IM technicians did not discuss clearance order tags for WO 692871-01 because a clearance order was not required for this type of work. After obtaining approval from the on shift operations crew, the IM technician noted the clearance order danger tag on the control switch of the 2D TIP drawer. Although the IM technician's pre-job briefing did not discuss the 2D TIP drawer having a clearance order tag, the lead IM technician did not question this information. Instead, the IM technician removed the drawer with the clearance order tag and placed the tag inside the WO.

After the lead IM technician completed the work and was returning the 2D TIP drawer to the control room on May 3, 2005, the Unit 2 unit supervisor noted the clearance order danger tag inside the WO. The licensee re-installed the 2D TIP drawer, re-hung the clearance order tag, and initiated a quick human performance investigation (QHPI). The licensee's investigation determined that of the two IM technicians conducting the work; only the lead IM technician had been aware of the clearance order danger tag. The second IM technician, who was responsible for only performing a verification that the correct drawer was identified for removal, did not notice the danger tag. The lead IM technician was not aware of the requirements specified in "Clearance and Tagging Procedure, "OP-MW-109-101," Revision 3, which prohibited the removal of a component from a system when the component had a danger tag attached to it. The IM lead technician assumed that the system was in a safer condition by removing the drawer. In addressing this issue, the licensee briefed this event to all maintenance personnel and added more detailed training on the clearance order process to the annual Nuclear-General Employee Training.

After the inspectors became aware of this issue, the inspectors informed the licensee that this potentially significant personnel safety event did not receive the appropriate level of concern and communication from the senior plant management. This issue was not discussed at the operations shift turnover or the plan-of-the-day meetings. Also, after the inspectors' review of the QHPI, the inspectors determined that this event was a repeat occurrence of an event on Unit 3 during the October 2004 refueling outage. The QHPI failed to identify that this was a repeat event and that the corrective actions were ineffective in preventing the recurrence of the May 2005 clearance order error. During the previous event on November 4, 2004, an electrician removed the 3B drywell cooler breaker which had been tagged out-of-service with a danger tag attached and in the racked to test position. The licensee had also conducted a QHPI for this event and implemented corrective actions which were limited to briefing electrical maintenance personnel on the event. Since the second QHPI failed to identify ineffective corrective actions from the first QHPI which also involved a clearance order error and both could have had significant personnel safety consequences, the inspectors questioned the appropriateness of conducting a QHPI for this type of event. Also, the inspectors were concerned that the boilerplate QHPI did not contain the required information to ensure previous events were reviewed while performing the QHPI. This was a concern to the inspectors because no other actions were planned by the licensee other than the performance of the QHPI, which would result in not discovering previous ineffective corrective actions. The licensee generated IR 346783, as a result of the inspectors' comments on the deficient aspects of the QHPI. In addition, the licensee briefed this event to all maintenance personnel and will conduct more detailed training on the clearance order process during annual site training.

<u>Analysis</u>: The inspectors determined that the licensee's failure to implement effective corrective actions from the November 2004 event and an IM technician's failure to apply annual clearance order training resulting in the repeat occurrence in May 2005 constituted a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on May 19, 2005. The inspectors concluded that the finding, if left uncorrected, would become a more significant safety concern by resulting in significant personnel safety consequences, and because it impacted the barrier integrity cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The primary cause of this finding was related to the cross-cutting areas of problem identification and resolution as well as human performance.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Appendix A, Attachment 1, dated December 1, 2004. The inspectors concluded that the finding impacted the barrier integrity cornerstone. Removal and re-installation of the 2D TIP drawer did not adversely affect the ability to ensure containment isolation using the ball check containment isolation valve. The inspectors answered 'Yes' to question 1 under the 'B' containment barrier cornerstone column, in that, the finding ultimately did not adversely affect containment isolation ability; and concluded that this issue was of very low safety significance (Green).

Enforcement: No violations of NRC requirements occurred because the finding involved non-safety related equipment. The licensee entered this issue into their corrective program as IR 346783. The licensee briefed this issue to all three maintenance shops and revised the annual Nuclear General Employee Training to include more detailed discussions on the clearance order process. (FIN 05000237/2005008-03)

4OA3 Event Follow-up (71153)

.1 (Closed) URI 05000249/2005003-01: Install U3 Core Spray Lower Sectional Replacement

b. Findings

Introduction: A Green finding involving a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control," and Criterion III, "Design Control.," was identified by the inspectors. The licensee failed to perform post-modification testing and to assure critical aspects of the core spray modification installation, which included obtaining gap measurement for mechanical joints, verifying the capability of the tooling to produce the required surface finishes on pre-fabricated components, and verifying that the pre-fabricated components were properly machined, met the leakage analysis specifications.

Description: During the Fall 2004 Unit 3 refueling outage, the licensee implemented engineering change 6602 for the replacement of the lower sectional piping of the core spray system. The modification was intended to replace piping inside the reactor vessel annulus that was susceptible to intergranular stress corrosion cracking (IGSCC) due to the environment and original welded materials (Type 304 stainless steel). The IGSCC could result in leakage from the piping into the annulus rendering the core spray system inoperable. The lower sectional replacement was designed by General Electric (GE) using IGSCC resistant materials with mechanical connections in lieu of eight previously welded connections to further mitigate susceptibility to IGSCC.

The modification consisted of cutting the core spray piping in the annulus at two points. The first, on a vertical section of pipe referred to as the downcomer area, and the second after the piping turned horizontal at the point where the piping enters the core shroud. This section, once cut out, would be replaced with an "L" shaped pre-fabricated piece of piping made of IGSCC resistant materials previously mentioned. The downcomer piping would be joined to the pre-fabricated piping using a compression fitting. After being cut, the downcomer was made up to a pre-fabricated ring such that there was a flat surface to surface contact. The bottom of the ring was rounded and mated with the flanged area of the pre-fabricated piping. The other end of the pre-fabricated piping was bolted to the core shroud.

General Electric performed GENE-0000-0021-4342-04, "Dresden Nuclear Power Station, Unit 3 Core Spray Line Lower Sectional Replacement Leakage Analysis," Revision 0. This analysis calculated the maximum gap sizes where mechanical components were joined together that would result in excess leakage outside the core shroud. Potential leakage pathways were between the downcomer pipe and the ring, between the ring and the flange, and between the pre-fabricated piping and the core shroud. An important component to the leakage analysis was the surface finishes of the cut piping and the pre-fabricated ring and flange. Exceeding the maximum gap size, described in the leakage analysis, could render one or more trains of the core spray system inoperable. Although these finishes were critical parameters in the modification, the licensee did not verify that the modification was bounded by the leakage analysis through the verification of maximum gap sizes or through post modification testing.

Since the licensee did not obtain these gap measurements, the inspectors requested the licensee to demonstrate how they ensured that the maximum gaps were not exceeded. The licensee was unable to provide documentation of compliance; however, the licensee along with GE demonstrated how the design of the mating surfaces between the pre-fabricated piping and the core shroud would ensure that the gap at that location would not be exceeded.

The licensee requested documentation from GE showing that the tooling used to make the piping cuts inside the reactor vessel annulus on the downcomer was capable of producing the surface finish specified in the GE leakage analysis. General Electric did not have any documentation that could demonstrate this capability at the time of the request. General Electric sent two coupons, that had been cut by the tooling used at Dresden, out for independent measurement. One of the two coupons did not meet the surface finish specification requirements and was due to dropping of the coupon after it had been cut at the site in San Jose, California. This action marred its finish and caused it to fail the test. The inspectors concurred with GE's conclusion of why the coupon failed after reviewing the applicable documentation.

The licensee requested that GE provide documentation to show that the pre-fabricated components were machined to the specifications described in the leakage analysis. Although documents were located, GE determined that the pre-fabricated ring did not meet the leakage analysis specifications. Subsequently, GE determined that the leakage analysis was still bounded by the new surface of the ring under GENE-0000-0021-4342-04, "Dresden Nuclear Power Station, Unit 3 Core Spray Line Lower Sectional Replacement," Revision 3.

Although the licensee failed to perform a post modification test or obtain gap measurements of the mechanical joints to ensure the modification was bounded by the leakage analysis, the licensee was able to demonstrate, with the assistance of GE that there was reasonable assurance that the modification was installed properly and that the maximum leakage specifications were not exceeded.

One of the station procedures that implemented Exelon Quality Assurance Manual, Topical Report, Revision 75, Chapter 11, was CC-AA-107-1001, "Post Modification Acceptance Testing, Revision 0. Step 4.2.3.5 of CC-AA-107-1001, stated that, "there are times when portions of the modification will not be tested or are unable to be tested. Justification for not testing at the site needs to be provided." The licensee stated that justification for not testing was never completed. The inspectors pointed out that CC-AA-107-1001 allowed for not testing modifications; however, the Exelon Quality Assurance Manual Topical Report did not. The inspectors determined by review of IR 343848, and through discussions with licensee management that the licensee planned to revise CC-AA-107, "Configuration Change Acceptance Testing Criteria," and/or CC-AA-107-1001. The procedure change would provide that the substitution for post modification testing would ensure quality at least equivalent to that specified in the original design bases. In addition, the licensee planned to confirm that the installed core spray modification had been installed with a level of quality equivalent to the original design basis.

Analysis: The licensee failed to perform post-modification testing and to assure critical aspects of the core spray modification installation, which included obtaining gap measurement for mechanical joints, verifying the capability of the tooling to produce the required surface finishes on pre-fabricated components, and verifying that the pre-fabricated components were properly machined, met the leakage analysis specifications was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on May 19, 2005 because it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences, specifically the design control attribute. The licensee, with assistance from GE was able to demonstrate proper installation of the core spray system piping modification inspite of the licensee's failure to ensure gap measurements for mechanical joints, verify the capability of the tooling, determine that the pre-fabricated components were properly machined, and conduct post modification testing to ensure the leakage analysis remained valid for these various aspects.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process," Appendix A, dated December 1, 2004. The inspectors determined that this finding impacted the mitigating system cornerstone. The inspectors entered the mitigating systems cornerstone column of the Phase I SDP sheet and answered No to all five questions. Therefore, the inspectors concluded that the finding was of very low safety significance (Green).

Enforcement: Title 10 of the Code of Federal Regulations Part 50, Appendix B, Criterion XI, states, a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program shall include ... operational tests during nuclear power plant operation, of structures, systems, and components.

The Exelon Quality Assurance Manual, Topical Report, Revision 75, Chapter 11, Test Control implements Title 10 of the Code of Federal Regulations Part 50, Appendix B, Criterion XI. The Exelon Quality Assurance Manual, Topical Report, Revision 75, states in Chapter 11, Test Control, Section 2.1.1, that the test program covers all required tests including the demonstration of satisfactory performance following plant maintenance or modifications. Section 2.7 states, in part, "The Company performs testing following plant modification or significant changes in operating procedures to confirm that the modification or changes produces the expected results."

Title 10 of the Code of Federal Regulations Part 50, Appendix B, Criterion III, Design Control, states in part, that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in § 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions. These measures shall include provisions to assure that appropriate quality standards are specified and included in design documents and that deviations from such standards are controlled.

Contrary to the above, from October 26, 2004, to December 11, 2004, the licensee installed Modification EC 6602, "Core Spray Lower Sectional Replacement," without performing post modification testing or assuring that appropriate quality standards were specified in installation procedures and instructions to ensure obtaining gap measurement for mechanical joints, verifying the capability of the tooling to produce the required surface finishes on pre-fabricated components, and verifying that the pre-fabricated components were properly machined in order to meet the leakage analysis specifications. Because this violation was of very low safety significance and because the issue was entered into the licensee's corrective action program (IR 303093, IR 325097, and IR 325133), the issue is being treated as a NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. (NCV 05000249/2005008-04)

.2 <u>(Closed) Licensee Event Report (LER) 50-237/2005-002-00:</u> Unit 2 Group 1 Isolation and Resulting Scram

On March 24, 2005, with Unit 2 at full power, an automatic scram occurred due to the malfunction of the "A" electro-hydraulic control system pressure regulator. All systems responded as expected to the scram. Initial investigation and troubleshooting activities by the licensee focused on the pressure regulator circuitry and card connections that could have caused the transient. However, no abnormalities were identified. In addition, the licensee sent the "A45", "C46", and "A54" cards from the "A" electro-hydraulic control pressure regulator circuitry to an offsite lab for failure analysis. No abnormalities or failed components were found.

A root cause investigation to determine the cause of the failure was initiated and concluded that the apparent cause of the failure was indeterminate. The licensee determined that the most probable cause of this event was attributed to an increase in electrical resistance between electrical pins 13 and 22 on card "A54." Also, calculations identified that an increase in electrical resistance of approximately 220 ohms for pin 22 or 2000 ohms for pin 13 could have caused the event. Corrective actions completed and planned by the licensee included the replacement of the "A45", "A54", and "C46" cards prior to startup; replacement of the "A54" card backplane connector; and rework of the remaining connectors to card "A54" during the Fall 2005 refueling outage. This LER was reviewed by the inspectors and no findings were identified. This LER is closed.

.3 <u>(Closed) LER 50-249/2004-005-00:</u> Unit 3 Isolation Condenser Time Delay Relays Exceed Technical Specification Allowable Value

b. Findings

Introduction: A Green finding involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, was identified by the inspectors. The licensee failed to implement adequate corrective actions to prevent recurrence of a deficient condition that occurred on September 6, 1996, which involved surveillance testing of the anticipated transient without scram (ATWS) time delay relays. This failure caused the Unit 3 isolation condenser (IC) time delay relays to exceed their TS allowable values due to the continued usage of the stopwatch as a calibration tool.

Description: On September 29, 2004, the licensee conducted DIS 1300-08, "Sustained High Reactor Pressure Time Delay Relay Calibration," Revision 2. Three of the four reactor high pressure IC initiation time delay relays were found out-of-tolerance and in non-compliance with TS requirements. The IC will initiate on a sustained high reactor pressure in a one-out-of-two twice logic. The purpose of the time delay was to avoid spurious initiations of the IC system by allowing time for the spurious pressure spike, caused by a main steam isolation or stop valve closure, to decay. The maximum time delay allowed per TS surveillance requirement 3.3.5.2.3 was 15 seconds. The as-found time delay relay setting values for high pressure switches 2-263-53A, 53B and 53C were 15.2, 15.8 and 15.1 seconds, respectively. IR 258172 was issued on September 29, 2004, to document this issue.

The inspectors had previously closed LER 50-249/96012-00, which discussed the out of tolerance of ATWS time delay relays, due to inadequate calibration check methodology. Three of the four low-low reactor water level ATWS time delay relays were found outside of the TS tolerance. The licensee determined that the initial failures were attributable to human error in using a stopwatch. In addressing this issue, the licensee switched to the use of a chart recorder to enhance time delay measurements. The licensee indicated that the testing methodology, that utilized the chart recorder, would produce more reliable and accurate results by eliminating human errors and reducing test equipment response time errors.

One of the corrective actions associated with the 1996 event was to revise safety related surveillance procedures to either increase the available margin to the TS allowable value and/or require the use of a measurement technique that was not affected by errors inherent in the use of stopwatches. A stopwatch was determined to be insensitive to calibration checks on components with limited margin. However, the IC time delay relays were not identified as affected components; therefore, the procedure was not revised.

The three relays that were outside the TS allowable value were last tested on June 16, 2002, using DIS 1300-01, "Sustained High Reactor Pressure Time Delay Relay Calibration," Revision 15. The relays were left within the as-left setting tolerance using a stopwatch. As a result, when the relays were tested on September 29, 2004, the as-found values for three of the relays were outside the TS limit which was a violation of the TS.

Analysis: The inspectors determined that the failure to have adequate corrective actions associated with repetitive failures of safety-related instruments was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” issued on May 19, 2005, because it impacted the mitigating system cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events and because it affected the reliability of a safety related component. The failure to utilize appropriate tools while performing instrument calibrations can result in equipment being outside of the TS allowable limits over the surveillance period and hence inadequate performance of safety related equipment. However, the IC system did not lose the ability to perform its safety function and all other mitigating systems were available. Therefore, this finding was considered to be of very low safety significance. The licensee was able to demonstrate, with the assistance of outside vendors, that during the period since the last calibration of the time delay relays, the IC system would have initiated at a time sooner than that assumed in the loss of feedwater transient analysis which was the most bounding analysis. The primary cause of this finding was related to the cross-cutting issue of problem identification and resolution.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, “Significance Determination Process,” Appendix A, Attachment 1, dated December 1, 2004. The inspectors concluded that the finding impacted the mitigating system cornerstone. The inspectors answered ‘No’ to all five questions under the mitigating system cornerstone column, and the issue screened as having very low safety significance (Green).

Enforcement: Appendix B, Criterion XVI of 10 CFR Part 50, required, 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 non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective actions taken to preclude repetition. Contrary to the above, the licensee implemented ineffective corrective actions to prevent recurrence of the 1996 event, involving out-of-tolerances of ATWS relays. This failure allowed the usage of stopwatches in the performance of safety related surveillances. As a result three relays were outside TS requirements after performing DIS 1300-01, Revision 15. As a result of the 2004 event, the licensee initiated IR 258172, created an action item to review the root cause of the event, revised the IC initiation time delay relay calibration procedure to require the use of a strip chart recorder, and created an action item to evaluate the extent of condition. Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program (IR 258172), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. (NCV 05000249/2005008-05)

4OA4 Cross-Cutting Findings

.1 A finding described in Section 4OA2.3(1) of this report had, as its primary cause, a problem identification and resolution issue, in that, the licensee was slow in identifying a failed damper in the reactor building ventilation system. As a result, a design deficiency with the standby gas treatment system, that caused a delay in the system’s ability to restore secondary containment to the required -0.25 inch differential pressure, continued to exist. The design deficiency had existed since original construction and remained masked by the damper failure until 2005.

.2 A finding described in 4OA2.3(4) of this report had, as its primary cause, problem identification and resolution as well as human performance, in that, the licensee failed to implement effective corrective actions for a November 2004 event involving the removal of equipment with a clearance order danger tag. As a result, a repeat event involving an instrument maintenance technician removing equipment with a clearance order danger tag occurred in May 2005. The instrument maintenance technician had received training on the clearance order process and should have been aware of the requirement that prohibited the removal of equipment when tagged in this manner.

.3 A finding described in Section 4OA3.3 of this report had, as its primary cause, problem identification and resolution. The licensee failed to implement adequate corrective actions to prevent recurrence of a deficient condition that occurred on September 6, 1996, which involved surveillance testing of ATWS time delay relays. This failure caused the Unit 3 isolation condenser time delay relays to exceed the TS allowable values due to the continued usage of a stopwatch as a calibration tool.

4OA5 Other Activities

.1 Operational Readiness of Offsite Power (Temporary Instruction (TI) 2515/163)

The objective of TI 2515/163, "Operational Readiness of Offsite Power," was to confirm, through inspections and interviews, the operational readiness of offsite power (OSP) systems in accordance with NRC requirements. On May 22-25, 2005, the inspectors reviewed licensee procedures and discuss the attributes identified in TI 2515/163 with licensee personnel. In accordance with the requirements of TI 2515/163, inspectors evaluated licensee procedures against the attributes discussed below.

The operating procedures that the control room operator uses to assure the operability of the OSP have the following attributes:

1. Identify the required control room operator actions to take when notified by the transmission system operator (TSO) that post-trip voltage of the OSP at the nuclear power plant will not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply.

2. Identify the compensatory actions the control room operator is required to perform if the TSO is not able to predict the post-trip voltage at the nuclear power plant for the current grid conditions.

3. Identify the notifications required by 10 CFR 50.72 for an inoperable offsite power system when the nuclear station is either informed by its TSO or when an actual degraded voltage condition is identified.

The procedures to ensure compliance with 10 CFR 50.65(a)(4) have the following attributes:

1. Direct the plant staff to perform grid reliability evaluations as part of the required maintenance risk assessment before taking a risk-significant piece of equipment out-of-service to do maintenance activities.

2. Direct the plant staff to ensure that the current status of the OSP system has been included in the risk management actions and compensatory actions to reduce the risk when performing risk-significant maintenance activities or when loss of offsite power or station blackout mitigating equipment are taken out-of-service.

3. Direct the control room staff to address degrading grid conditions that may emerge during a maintenance activity.

4. Direct the plant staff to notify the TSO of risk changes that emerge during ongoing maintenance at the nuclear power plant.

The procedures to ensure compliance with 10 CFR 50.63 have the following attribute:

1. Direct the control room operators on the steps to be taken to try to recover offsite power within the station blackout coping time.

The results of the inspectors' review were forwarded to office of Nuclear Reactor Regulation for further review and evaluation. "

.2 <u>Operation of an Independent Spent Fuel Storage Installation (ISFSI) (60855.1)</u>

a. <u>Inspection Scope</u>

The inspectors evaluated the licensee’s response to the failure of the cask transfer facility (CTF) while the CTF was lifting a cask loaded with fuel. The inspectors reviewed the prompt investigation report, a condition report, and an engineering evaluation associated with the incident. The inspectors also reviewed the certificate of compliance (CoC), the technical specifications, the Safety Evaluation Report, Revision 1, the Final Safety Analysis Report (FSAR), Revision 2, and the Calculation Package On Hitran-140, Revision 2. The purpose of the review was to verify that the cask configuration had been analyzed to withstand natural phenomena such as tornados, earthquake, tornado missile strike, and a vertical drop, and that the radiation dose rates contained in the technical specifications were not exceeded. The inspectors also reviewed the 10 CFR 72.48 safety screening/evaluation and the special procedure, “Hi-Track setdown at the CTF (Action Tracking Item (ATI) 340904-14),” to verify that the use of an alternative lifting device with four hydraulic lifting boom systems conformed with conditions of the CoC , the technical specifications, and the FSAR.

b. <u>Findings</u>

No findings of significance were identified

4OA6 Meetings

.1 Interim Exit Meeting

Interim exit meetings were conducted for:

- Maintenance Effectiveness Periodic Evaluation with D. Bost, Site Vice President on April 15, 2005;
- Radiation Protection (RETS/ODCM) inspection with Mr. D. Bost and other licensee staff on April 29, 2005;
- Licensed Operator Requalification 71111.11 with Mr. M. Otten, Operations Requalification Training Supervisor on June 16, 2005, via telephone; and
- Independent Spent Fuel Storage Installation with Mr. M. Mikota, Dry Cask Project Manager, via telephone, on June 21, 2005.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee

D. Bost, Site Vice President
D. Wozniak, Plant Manager
S. Bell, Shipping Specialist
H. Bush, Radiological Engineering Manager
R. Conklin, Radiation Protection Supervisor
J. Fox, Design Engineer
R. Gadbois, Operations Director
D. Galanis, Design Engineering Manager
V. Gengler, Dresden Site Security Director
J. Griffin, Regulatory Assurance - NRC Coordinator
P. Salas, Regulatory Assurance Manager
J. Kalb, Environmental/ODCM Chemist
A. Khanifar, Nuclear Oversight Director
S. Kroma, Reactor Services Project Manager
T. Loch, Supervisor, Design Engineering
M. McGivern, System Engineer
M. Mikota, Dry Cask Project Manager, Dresden
D. Moore, Dry Cask Project Manager, Quad Cities
D. Nestle, Radiation Protection Technical Manager
M. Otten, Operations Requalification Training Supervisor
M. Overstreet, Radiation Protection Supervisor
R. Quick, Security Manager
N. Spooner, Site Maintenance Rule Coordinator
J. Strmec, Chemistry Manager
B. Surges, Operations Requalification Training Supervisor
G. Bockholdt, Maintenance Director
S. Taylor, Radiation Protection Director

NRC

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

IEMA

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

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000237/2005008-01 | URI | Inability to Trip the 2B Service Water Pump from the Control Room |
| 05000237/2005008-02<br>05000249/2005008-02 | FIN | Failure of the Refuel Floor Damper & Design Deficiency with the Standby Gas Treatment System |
| 05000237/2005008-03 | FIN | Removal of the 2D Traversing Incore Probe Drawer With Clearance Order Danger Tag Attached |
| 05000249/2005008-04 | NCV | Modification to the Unit 3 Core Spray Piping |
| 05000249/2005008-05 | NCV | Isolation Condenser Time Delay Relays Exceed TS Value |

Closed

| | | |
|---|---|---|
| 05000237/2005008-02<br>05000249/2005008-02 | FIN | Failure of the Refuel Floor Damper & Design Deficiency with the Standby Gas Treatment System |
| 05000237/2005008-03 | FIN | Removal of the 2D Traversing Incore Probe Drawer With Clearance Order Danger Tag Attached |
| 05000249/2005008-04 | NCV | Modification to the Unit 3 Core Spray Piping |
| 05000249/2005008-05 | NCV | Isolation Condenser Time Delay Relays Exceed TS Value (4OA3.4) |
| 05000249/2005003-01 | URI | Install U3 Core Spray Lower Sectional Replacement |
| 50-249/2004-005-00 | LER | Unit 3 Isolation Condenser Time Delay Relays Exceed Technical Specification Allowable Value |
| 50-237/2005-002-00 | LER | Unit 2 Group 1 Isolation and Resulting Scram |

Discussed

None

## LIST OF DOCUMENTS REVIEWED

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

1R04 Equipment Alignment

-DOP 6900-E4; Revision 11; Unit 2 Electrical Systems Checklist
-DOP 6900-E1; Revision 07; Unit 3 Electrical Systems Checklist
-DOP 7500-M1/E1; Revision 06; Unit 2/3 Standby Gas Treatment
-OP-MW-109-101; Revision 2, Attachment 14; Worker Tagout Form Part 1: Hang/Lift Section; Tagout # 2005-3131
-DOP 1400-M1; Revision 20; Unit 3 Core Spray System
-DOP 1400-E1; Revision 03; Unit 2 Core Spray Electrical
-DOP 1400-M1/E1; Revision 17; Unit 3 Core Spray System
-DOP 0900-E1; Revision 20; Unit 2(3) Control Room Panels
-DOP 1500-E1; Revision 13; Unit 3 LPCI and CCSW Electrical
-DOP 1500-M1; Revision 29; Unit 3 LPCI and Containment Cooling Valve Checklist
-DOP 1500-01; Revision 13; Preparation of Low Pressure Coolant Injection for Automatic Start
-DOP 1500-02; Revision 50; Torus Water Cooling Mode of Low Pressure Coolant Injection System
-DOP 1500-03; Revision 29; Containment Spray Cooling Mode of Low Pressure Coolant Injection System
-DOP 1500-05; Revision 14; LPCI System Operation and/or Shutdown After Automatic Initiation
-IR 344388; LPCI Thermal Performance Calculations Delayed; June 9, 2005
-IR 342659; Flow Transmitter Found Out of Tolerance During Calibration; June 9, 2005
-IR 314046; CCSW Pump Vibration in the Alert Range; March 17, 2005
-IR 295277/295464; Unit 3 CCSW Flow Instrumentation Piping Improperly Supported; January 28, 2005
-IR 293713; Pipe Degradation of 2C & 2D CCSW Pump Discharge Elbows; January 24, 2005
-DWG M-355; Diagram of Service Water Piping; Revision RP
-DWG M-360; Sheet 1; Diagram of L.P. Coolant Injection Piping; Revision VK
-DWG M-360; Sheet 2; Diagram of L.P. Coolant Injection Piping; Revision AV

1R05 Fire Protection

-Dresden Fire Pre-Plan U2TB-43; Revision 05
-Dresden Fire Pre-Plan U2TB-45; Revision 05
-Dresden Fire Pre-Plan U2TB-51; Revision 05
-Dresden Fire Pre-Plan U3TB-76; Revision 05

-Dresden Fire Pre-Plan U2/3DG-105; Revision 05
-IR 328975; Low Water Level in Ssd Light Batteries; May 2, 2005
-IR 333918; Bell Alarm for 3 Detectors Only Buzzes; May 10, 2005
-IR 334382; Green Normal Power Light Is out Wih No Trouble or Alarm LIG; May 12, 2005
-IR 336018; 1-4199-H-TV Leaks by the Seat; May 17, 2005
-IR 336146; 3-7902-396, BOP EM Light 396 Has Solid Fast Charge Light on; May 18, 2005
-IR 336779; 2-7902-285, SSD Light Battery Requires Replacement; May 19, 2005
-IR 337075; Two NLO's Do Not Indicate Qualified in PQD; May 20, 2005
-IR 337139; Two NLS's Respirator Mask Med. Qualifications Were Not Met; May 20, 2005
-IR 337503; Weaknesses for 2nd Quarter Fire Drill; May 23, 2005
-IR 338671; Dresden Fire Protection Report; May 26, 2005

1R06 Flooding

-IR 302902; 2/3 Cribhouse Sump Failure; February 18, 2005
-IR 331158; U2 west side ECCS Corner Room Watertight Door ½" Ajar; May 2, 2005
-IR 331423; 2/3 Cribhouse (UHS) Sump Pump Failure; May 3, 2005
-IR 331583; LS-3-4941-8 May Be Impacted by Temporary Staged Equipment; May 3, 2005
-IR 333678; Shift Manager Fails to Generate PINV Assignment for Prompt; May 10, 2005
-IR 337100; NRC Questions Timeliness of 2/3 Cribhouse Sump Repairs; May 17, 2005
-IR 337105; Troubleshooting WO Documentation Incomplete; May 20, 2005
-IR 337135; NRC ID's FIN Backlog Issue; May 16, 2005
-IR 338392; SOC Enters Incorrect Information in IR; May 25, 2005
-WO 784571; 2/3 Cribhouse Sump Failure; February 23, 2005
-DOA 0040-02; Localized Flooding in Plant; Revision 15
-NRC Information Notice 2005-11; Internal Flooding / Spray-down of Safety Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains; May 6, 2005
-WC-AA-106; Revision 2

1R07 Heat Sink

-IR 331949; Corrosion of Channel Head on RBCCW Heat Exchanger; May 4, 2005
-IR 332102; 2A TBCCW Heat Exchanger End Covers Are Degraded; May 5, 2005
-IR 332659; Maintenance Rule Database Incorrect; May 6, 2005

1R11 Operator Requalification

-IR 326406; Breaker Inspection Finds Trip Coil Incorrectly Mounted; April 19, 2005
-IR 330042; The Results of the FASA on LORT Exam Readiness - 4 Recom.; April 29, 2005
-IR 334912; NOS Identifies Minor Exam Security Issue; May 13, 2005

1R12 Maintenance Effectiveness

-IR 181118; Floor drains backed up in U2 HPCI contaminated floor space; October 14, 2005
-IR 198770; HPCI Inoperable on Unit 2; February 1, 2004
-IR 198824; RBEDT pump down rate clos; February 1, 2004
-IR 201799; Failed Surveillance on U1 Battery Charger Swap; February 13, 2004
-IR 219445; CCSW Piping Degradation Exceeds Code Minimum; May 6, 2004
-IR 268340; Corporate PE FASA "Procurement Engineering Assessment Plan"; February 24, 2005
-IR 270869; Received Alarm (923-4) D-1, 3B/D RBFD Sump PP Trip/Isol; November 5, 2004
-IR 308487; Maintenance Rule Quarterly Evals Not Performed for Iso Cond.; March 3, 2005
-IR 325977; Risk Tool Does Not Model RAT Breaker to Bus 34; April 18, 2005
-IR 327965; U2 CRD P-4 PMT Failed Due to Seat Leakage - Repeat Issue; May 13, 2005
-IR 333736; Maint. Rule Database Support Documentation Needs Update; May 10, 2005
-IR 334228; Maintenance Rule Functional Failure Criteria Needs to Be Eval; May 11, 2005
-IR 336506; Maintenance Rule Evaluations Not Completed as Required; May 17, 2005
-ER-AA-310-1001; Maintenance Rule - Scoping; Revision 1

IR12 Maintenance Effectivenss (71111.12B)

-Maintenance Rule Periodic Assessment #5; October 1, 2002 - September 30, 2004; dated December 2004
-Shutdown Cooling (a)(1) Action Plan; dated January 9, 2003
-Reactor Coolant Pressure Boundary (a)(1) Action Plan; dated December 18, 2003
-Secondary Containment (a)(1) Action Plan; dated May 22, 2003
-CCSW Supply to CR HVAC (a)(1) Action Plan; dated January 31, 2002
-Instrument Air (a)(1) Action Plan; dated January 20, 2005
-Augmented Primary Containment Vent (a)(1) Action Plan; dated July 16, 2004
-Feedwater Unit 2 (a)(1) Action Plan; dated January 22, 2004
-Service Water Standby Coolant Supply (a)(1) Action Plan; dated December 18, 2003
-List of Maintenance Rule Equipment Monitored for Unavailability; dated March, 2005
-List of Functional Failures for Assessment Period from October 1, 2002 - September 30, 2004; dated October 2004
-Expert Panel Meeting Minutes; dated January 31, 2003
-Expert Panel Meeting Minutes; dated June 24, 2003
-Expert Panel Meeting Minutes; dated September 11, 2003
-Expert Panel Meeting Minutes; dated February 12, 2004
-Expert Panel Meeting Minutes; dated May 21, 2004
-Expert Panel Meeting Minutes; dated August 5, 2004
-HPCI System Health Overview Report; December 2004
-125 VDC System Health Overview Report; December 2004
-CCSW Quarterly Ship System Report; December 2004
-Primary Containment System Health Overview Report; December 2004

-ER-AA-310; Implementation of the Maintenance Rule; Revision 3
-ER-AA-310-1003; Maintenance Rule - Performance Criteria Selection; Revision 2
-ER-AA-310-1004; Maintenance Rule - Performance Monitoring; Revision 2
-ER-AA-310-1005; Maintenance Rule - Dispositioning Between (a)(1) and (a)(2); Revision 2
-ER-AA-310-1007; Maintenance Rule - Periodic (a)(3) Assessment; Revision 3
-MA-AA-716-210; Performance Centered Maintenance (PCM) Process; Revision 3
-MA-AS-716-210-1001; Performance Centered Maintenance Templates; dated July 26, 2004
-SA-1126; Probability Risk Assessment Basis for Dresden Maintenance Rule Availability, Performance Criteria and Revisions to Reliability Performance Criteria; Revision 0
-Focused Area Self-assessment - Dresden Maintenance Rule Program (ATI 178673-01); dated October 1, 2003

1R13 Maintenance Risk Assessments and Emergent Work Control

-IR 333497; Inadequate Preparation Causes Schedule Delay; May 10, 2005
-IR 333822; HLAS Generated Within the Execution Week Without and IR; May 10, 2005
-IR 336144; Unit 3 125 Vdc Battery Discharge Test Stopped Prematurely; May 18, 2005

1R15 Operability Evaluations

-IR 324995; 2B Service Water Pump Breaker Failed to Trip from C/S; April 15, 2005
-IR 328459; Pipe Support for Line 2-3711-21/2" L is Damaged; April 25, 2005
-IR 328461; Feedwater Sparger End Bracket Pin Stops Are Loosening; April 25, 2005
-IR 329880; Ineffective CA Taken 3B Recirc Seal Hydro Failure in D3R18; April 28, 2005
-IR 333831; NOS Identifies OPS Not Following Guidance in LS-AA-120; May 10, 2005
-IR 336707; NRC & IEMA Req. For Additional Clarification for 50.50 Eval; May 19, 2005
-Operability Evaluation No. 04-015
-EC No. 352592; Operability Evaluation for Isolation Condenser Steam Supply Vent Lines 2-1309-3/4"- A, 2-1308-3/4"- A, and 2-1307-3/4"- A
-EC No. 353273; Modify U2 IsCo Steam Supply Vent Line Supports
-NES-MS-03.2; Revision 5; Evaluation of Discrepant Piping and Support Systems
-Specification K-4080; Revision 12; General Work Specification, Maintenance/Modification Work
-USA Standard Code for Pressure Piping B31.1.0, Power Piping; 1967
-American Society of Mechanical Engineers Code, Section III, Division I; 1976
-Dresden UFSAR Sections 3.9.3.1.3.1.1 (Acceptance Criteria) and 5.4.6 (Isolation Condenser)

1R16 Operator Work-Around

-OP-AA-102-103; Operator Work-Around Program; Revision 1

1R17 Permanent Plant Modification

-IR 303093; IEMA [Illinois Emergency Management Agency] Inspector Questions PMT [Post Modification Testing] for Core Spray Modification; February 18, 2005

-IR 325133; NRC Questions QATR [Quality Assurance Topical Report] Consistency With CC [Configuration Change] Procedure; April 15, 2005
-IR 325097; EC [Engineering Change] 6602 Lacks Documented Justification for No PMT [Post-Modification Testing]; April 15, 2005
-IR 330762; PMT for 2-1901-40 U2 FPC Filt Demin Byp AOV Mod Failed; May 24, 2005
-WO 97010448-06; Install Lower Sectional Replacement Piping as Required
-GENE-0000-0021-4342-04; Dresden Nuclear Power Station, Unit 3 Core Spray Line Lower Sectional Replacement; Revision 0
-GENE-0000-0021-4342-04; Dresden Nuclear Power Station, Unit 3 Core Spray Line Lower Sectional Replacement; Revision 1
-GENE-0000-0021-4342-04; Dresden Nuclear Power Station, Unit 3 Core Spray Line Lower Sectional Replacement; Revision 3
-Field Deviation Disposition Request RMCN05077; Revision 0; dated October 8, 2004
-Terminal Manufacturing Company, Mechanical Measurements Inspection Report; Job Number 11007- 1 & 2; dated April 1, 2005;

1R19 Post Maintenance Testing

-DOS 4400-01; Containment Cooling Service Water Vault Floor Drain; Revision 08
-DIS 3900-05; Diesel Generator Cooling Water Flow Indication Calibration; Revision 04
-DOS 6600-08; Diesel Generator Cooling Water Pump Quarterly and Comprehensive/Progressive Test for Operational Readiness and In-Service Test (IST) Program; Revision 32
-WO Package 00777955-01; D2/3 QTS TS D/G Cooling Water Pump Test for IST Program Surveillance
-IR 324995; 2B Service Water Pump Breaker Failed to Trip from C/S; April 15, 2005
-IR 325097; EC 6602 Lacks Documented Justification for No PMT; May 5, 2005
-IR 329020; Perform and Document Extent of Condition Reviews 4KV BKR; April 28, 2005
-IR 330004; D3M11 Forced Outage Due to 3B Rx. Recirc. Pp.seal Failure; April 29, 2005
-IR 335891; RC EOC Discovered Another Recirc Seal Reverse Press Event; May 17, 2005
-IR 329888; Initiate Root Cause for 3b Recirc Pump Seal Degradation; April 28, 2005

1R20 Outage Activities

-IR 324800; TR 29 Outage During D2R19 Requires Unit 3 Shutdown; April 14, 2005
-IR 329242; D3M11: Found Loose Hardware on 3E ERV Microswitch; May 24, 2005
-IR 329541; D3M11 Post-job Critique (OPS-Nightshift); April 28, 2005
-IR 330355; Equipment Status Tags Log Entry Report; May 11, 2005
-IR 331080; Limit Switch #1 for IRM#14 Drive Circuit Not Working; May 2, 2005
-IR 333410; Data Recorded in Incorrect ROWS on NF-AB-715 Attachment 2; April 29, 2005
-IR 333418; Delays During U3 Startup Following D3M11; May 9, 2005
-IR 330503; NRC Identified Items During U3 Drywell Close Out, D3M11; April 30, 2005
-IR 330547; D3M11 Drywell Closeout Discrepancies; April 30, 2005

1R22 Surveillance Testing

-IR 324377; Increase in U2 DW under Vessel Temp Points 24, 25, and 26; April 15, 2005
-IR 324858; IR Not Written to Revise DIS 0263-01; April 14, 2005
-IR 329649; 2 of 8 MSIVs Timed Unsat During Surveillance; April 28, 2005
-IR 329880; Ineffective CA Taken 3B Recirc Seal Hydro Failure in D3R18; April 28, 2005
-IR 329904; Potential Error Occurred During D3R18 3B RR Motor Work; April 28, 2005
-IR 330844; 2-1349-B Iso. Condenser High Flow Ind/switch Out of Spec; May 2, 2005
-IR 332046; 3-1705-16B Fuel Ppol CH B Out of Tolerance; May 5, 2005
-IR 333412; No Feedback Ever Given on Negative Scorecards; May 9, 2005
-IR 335633; D2 Core Flow Found Outside Procedural Tolerance During CAL; May 16, 2005
-IR 335776; Timing on Relay Was Found to Be out of Tolerance; May 17, 2005
-IR 335900; Unit 3 #14-51 Accum Pressure Switch Out-of-Tolerance; May 17, 2005
-IR 336123; D3 HCU Pressure Switch 30-19 Out of Tolerance; May 17, 2005
-IR 337554; Reset Operations Team Event Clock; May 23, 2005
-IR 338564; U1 125 VDC Battery Float Voltage Out of Tolerance; May 26, 2005
-IR 348496; U2 SBO Panel 2202-105 Alarm Tiles Not Functioning; June 29, 2005
-WO 00570002; D2 24M TS Div 1 LPCI Cont Cooling System Functional Test; March 24, 2005
-DOS 6600-01; Diesel Generator Surveillance Tests; Revision 88
-DOS 6620-07; SBO 2 (3) Diesel Generator Surveillance Tests; Revision 18
-WO Package 00547472
-WO Package 00810022
-WO Package 00788502
-WO Package 00788507
-Unit NSO Daily Surveillance Log; Unit 2(3), Appendix A, Revision 98

1R23 Temporary Plant Modifications

-OP-AA-106-101-1006; Revision 1; Operational and Technical Decision Making Process
-CC-MW-112-1001; Training and Reference Material for Temporary Configuration Changes
-Dresden FSAR 15.1.3; Increase in Steam Flow
-Dresden FSAR 15.1.3.2; Sequence of Events and System Operation
-Dresden FSAR 15.2; Decrease in Heat Removal by the Reactor Coolant System
-Dresden FSAR 15.2.1; Steam Pressure Regulator Malfunction
-Dresden FSAR 15.2.2.1; Load Rejection Without Bypass
-Dresden FSAR 15.2.3.1; Turbine Trip Without Bypass
-Drawing 12E-2910S; Schematic Diagram Electro-Hydraulic Control System Pressure Control Unit; Revision B
-IR 330827; Temporary power cord usage; May 2, 2005
-IR 333103; LD has control of U2 output CB through SCADA; May 27, 2005
-IR 333454; DIS 0600-05 reactor narrow range level calibration; May 10, 2005
-IR 333797; Inappropriate revision to WO during D3M11; May 10, 2005

2PS1 <u>Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems</u>

-Offsite Dose Calculation Manual; Chapters 2, 4, and Appendix A (Revision 2), Chapter 10 (Revision 4), Chapter 12 (Revision 5), and Appendix F (Revision 2)
-Dresden Nuclear Power Station Radioactive Effluent Release Reports for Calendar Years 2002, 2003, and the 2004 Draft Report; dated April 30, 2003, April 30, 2004 and Undated 2004 Draft Report, respectively
-CY-DR-170-2020/2030; Abnormal/Unmonitored Radiological Release; Revision 0
-Dresden Computation for Mn-54 Identified in Service Water Sample (DAR-2002-04); dated April 7, 2003
-Radiation Protection Memorandum 99-001; Unit 1 Main Turbine Floor Effluents; dated January 4, 1999
-DCP 3207-01; Gamma Isotopic Analysis; Revision 19
-DCP 2000-28; River Discharge; Revision 17
-CY-DR-120-600; Liquid Radwaste Scaling Factors; Revision 1
-CY-DR-170-210; Main Chimney Sampling; Revision 0
-Annual/Semi-Annual Surveillance Records of Unit 2/3 Radwaste High Radiation Area Room Material Condition Inspections; 2004 through March 2005
-IR 00250661; Floor Drain and Waste Collector Tank Room Has Leaks; September 7, 2004
-DIS-1700-14; Unit 2/3 Reactor Building Vent Stack SPING Calibration; December 12, 2003
-DRS 5821-56; SPING Effluent Monitor Calibration; dated December 15, 2003
-DIS-1700-14; Unit 2/3 Main Chimney SPING Calibration; dated January 16, 2004
-DRS 5821-56; Main Chimney Radiation Monitor SPING Calibration; dated January 22, 2004
-DIS 3900-01; Unit 2 Service Water Effluent Radiation Monitor Calibration; dated June 4, 2003
-DIS 3900-01; Unit 3 Service Water Effluent Radiation Monitor Calibration; dated April 16, 2004
-DRS 5830-01; Unit 3 Service Water Monitor Calibration; dated November 6, 2004
-DRS 5830-01; Unit 2/3 Liquid Radwaste Discharge Monitor Calibration; dated March 26, 2004
-DIS 1300-04; Unit 2 Isolation Condenser Vent Radiation Monitor Calibration; dated February 10, 2005
-DIS 1300-04; Unit 3 Isolation Condenser Vent Radiation Monitor Calibration; dated February 11, 2005
-DIS 5700-03; Unit 2/3 Chimney Flow Monitor Calibration; dated July 21, 2003
-DIS 5700-02; Unit 2/3 Reactor Building Vent Stack Flow Calibration; dated June 14, 2004
-Results of “Analytics” Radiochemistry Cross-Check Program for Dresden Nuclear Power Station; Quarterly Results for 1$^{st}$ Quarter 2004 - 1$^{st}$ Quarter 2005
-Efficiency Calibrations and Lower Limit of Detection Determinations for Gamma Spectroscopy Systems (6 detectors with multiple geometries); dated various periods between January 2000 and April 2005
-Liquid Scintillation Counter (serial number 402097) Calibration and Lower Limit of Detection Determination; dated January 25, 2005
-DTS 7500-13; Standby Gas Treatment System Visual Inspection (Train A and Train B); dated May 26, 2004 and May 25, 2004, respectively

-DTS 7500-07; Standby Gas Treatment System Charcoal Absorber Leak Test (Train A and Train B); dated May 26, 2004 and May 25, 2004, respectively
-NCS Corporation Radioiodine Retention/Penetration/Efficiency Test Report; dated June 9, 2004 (Train A - East and West Banks); dated May 28, 2004 (Train B - East Bank)
-IR 00311151 and 00311622; Activity Detected in Unit 3 and Unit 2 Service Water Effluent Samples; March 10 and 11, 2005
-IR 00315849; Increased Tritium in Well T-1; March 22, 2005
-IR 00317313; Service Water Sampling Requirements per ODCM; March 25, 2005
-IR 00326931; Unit 2/3 Chimney SPING Data Indication 'Flush' Mode; April 20, 2005
-Audit NOSA-DRE-03-08; Radiological Environmental Monitoring Program, ODCM, Non-Radiological Effluent Monitoring Audit Report; dated November 19, 2003
-Focus Area Self-Assessment Report; Radiological Effluent Control; dated March 14, 2005
-Audit NOSA-DRE-04-04; Chemistry, Radwaste and Process Control Program; dated May 25, 2004
-IR 00289411; Sludge Found During High Radiation Room Inspection; January 10, 2005
-DTS 7500-11; DOP Testing of Unit 2/3 Standby Gas Treatment System HEPA Filters (Train A and Train B); dated May 25 and May 26, 2004
-DOS 7500-02; Standby Gas Treatment System Surveillance and IST Test; dated April 2, 2005

4OA1 Performance Indicator Verification

-Summary of Quarterly Dose Calculations from Liquid and Gaseous Effluents for 2004 through March 2005

4OA2 Identification and Resolution of Problems (71152)

-IR 239066; Negative Safety Trend Identified Within Security Department; April 26, 2005
-IR 324732; Operator Aid #159 Turnover Checklists; April 14, 2005
-IR 324902; NRC Identified Concerns; April 14, 2005
-IR 326630; U3 DW Hi Temp Alarm Setpoint Non-conservative vs. DEOP; April 20, 2005
-IR 327295; NOS Audit NOSA-DRE-05-01 (AR 287372) - Deficiency #1; May 11, 2005
-IR 327336; NRC Questions Actions Taken in SOC and MRC Closure of IRS; April 21, 2005
-IR 329017; Generator H2 Pressure Dropped During Unit Shutdown; May 13, 2005
-IR 329045; Cracked Weld on U2 EDG Air Box Mount; May 24, 2005
-IR 329698; Large Quantity of Air Entrained in U3 Turbine Lube Oil; April 28, 2005
-IR 330004; D3M11 Forced Outage Due to 3b Rx. Recirc. PP.Seal Failure; April 29, 2005
-IR 330030; Aggregate Reviews / Status of HCU PM 2005 Implementation; April 29, 2005
-IR 330591; 3A MSDT Level Transmitter Calibration Drift; April 30, 2005
-IR 331420; Unplanned DOA 6500-12, Low Switchyard Voltage Entry; May 3, 2005
-IR 331430; Entered DOA 6500-11 for High Voltage on Bus 24-1; May 3, 2005
-IR 331875; M&TE Unable to Locate; May 4, 2005
-IR 331968; IEMA Representative Questions ECR for IR 326630; May 4, 2005

-IR 332047; Unplanned Tech Spec Entry; May 5, 2005
-IR 332346; High Temperature (197 Deg F) on A Phase Bkr Supply Cable; May 5, 2005
-IR 332358; High Temperature (180 Deg F) on B Phase Bkr Supply Cable; May 5, 2005
-IR 332363; High Temperature (150 Deg F) on Hot Clg Twr MCC 2/3-7856-2B2; May 5, 2005
-IR 333057; DGA-12 Hard Card Revised but Not the Procedure Section; May 9, 2005
-IR 333892; Inadequate Corrective Action Documentation in ATI 310957-02; May 10, 2005
-IR 334295; Adverse Trend - Rising Water Level in Unit 3 Torus; May 11, 2005
-IR 334413; U3 125 Vdc Battery Cell 23 Sample Tube; May 12, 2005
-IR 335710; RB DP Low Condition for about 30 Seconds; May 16, 2005
-IR 335752; Experienced Difficulties Contacting BOC Gas; May 17, 2005
-IR 336040; NOS IDs Unidentified Cables/hoses; May 17, 2005
-IR 336506; Maintenance Rule Evaluations Not Completed as Required; May 18, 2005
-IR 337285; Fuel Pool Channel "A" Rad Hi Alarm; May 20, 2005
-IR 337403; Enter TS 3.3.6.2 Because of Failed Refuel FLR Rad Monitor; May 22, 2005
-IR 338273; NOS Ids Commitment Management Deficiency; May 25, 2005
-IR 338300; U2 SWRM Declared Inoperable; May 25, 2005
-IR 346783; Corrective Actions Not Effective ATI 270871; June 23, 2005

4OA3 Event Follow-up (71153)

-IR 325097; EC 6602 Lacks Documented Justification for no PMT; April 15, 2005

4OA5 Other Activities

TI 2515/163 Operation Readiness of Offsite Power

-IR 326685; Enter DOA 6500-12 and TS 3.8.1; May 11, 2005
-IR 333057; DGA-12 Hard Card Revised but Not the Procedure Section; May 9, 2005
-IR 333697; DOA 6500-12 Entered for Low Post Trip Red Bus Voltage; May 10, 2005

Operation of an Independent Spent Fuel Storage Installation (ISFSI) (60855.1)

-Certificate of Compliance (CoC) and the Technical Specifications; Revision 1
-Safety Evaluation Report; Revision 1
-Final Safety Analysis Report (FSAR); Revision 2
-Calculation Package On Hitran-140; Revision 2
-Prompt Investigation Report, No. 340904; Cask Transfer Facility (CTF) Lift Stopped With Loaded Cask
-Engineering Evaluation, EC Eval 355831; Evaluation of Suspended Hi-Trac Storage Unit in Cask Transfer Facility; Revision 0
-WO 817345-01; Troubleshooting and Repair of the CTF Instructions
-Maintenance Logs; dated April 7, 2005
-Condition Report; CTF Failure; dated June 6, 2005
-DAP 10-14A; Hi-Track Setdown at the CTF (ATI 340904-14) & Structural Qualification of Hi-Track Recovery from DNPS CTF Drive Failure (AR340904);
72.48 Screening/Evaluation
-Special Procedure SP 05-05-006; Hi-Track Setdown at the CTF (ATI 340904-14); Revision 0

## LIST OF ACRONYMS USED

| | |
|---|---|
| ADAMS | Agencywide Documents Access and Management System |
| ATI | Action Tracking Item |
| ATWS | Anticipated Transient Without Scram |
| CAP | Corrective Action Program |
| CCSW | Containment Cooling Service Water System |
| CoC | Certificate of Compliance |
| CFR | Code of Federal Regulations |
| CR | Condition Report |
| CTF | Cask Transfer Facility |
| DIS | Dresden Instrument Surveillance |
| DOA | Dresden Operating Abnormal Procedure |
| DOS | Dresden Operating Surveillance |
| dP | Differential Pressure |
| DRP | Division of Reactor Projects |
| DRS | Division of Reactor Safety |
| FIN | Finding |
| FSAR | Final Safety Analysis Report |
| GE | General Electric |
| HEPA | High Efficiency Particulate Air |
| HPCI | High Pressure Core Injection System |
| IC | Isolation Condenser |
| IGSCC | Intergranular Stress Corrosion Cracking |
| IM | Instrument Maintenance |
| IEMA | Illinois Emergency Management Agency |
| IMC | Inspection Manual Chapter |
| IR | Issue Report |
| LER | Licensee Event Report |
| MRC | Management Review Committee |
| MWe | megawatts electrical |
| NCV | Non-Cited Violation |
| NRC | Nuclear Regulatory Commission |
| ODCM | Offsite Dose Calculation Manual |
| OSP | Offsite Power |
| PARS | Publicly Available Records |
| PI | Performance Indicator |
| QHPI | Quick Human Performance Investigation |
| RETS | Radiological Effluent Technical Specifications |
| SBGT | Standby Gas Treatment System |
| SDP | Significance Determination Process |
| SOC | Site Ownership Committee |
| SPING | Station Particulate, Iodine and Noble Gas Monitor |
| SSC | Structures, Systems, and Components |
| SW | Service Water |
| TI | Temporary Instruction |
| TIP | Traversing Incore Probe |

| | |
|---|---|
| TS | Technical Specification |
| TSO | Transmission System Operator |
| UFSAR | Updated Final Safety Analysis Report |
| URI | Unresolved Item |
| WO | Work Order |