UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

August 7, 2015

EA-15-115

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: DRESDEN NUCLEAR POWER STATION, UNITS 2 AND 3 - INTEGRATED INSPECTION REPORT 05000237/2015002; 05000249/2015002; 07200037/2015001 AND PRELIMINARY WHITE FINDING

Dear Mr. Hanson:

On June 30, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Dresden Nuclear Power Station, Units 2 and 3. The enclosed report documents the results of this inspection, which were discussed on July 1, 2015, with Mr. S. Marik, and other members of your staff. Additionally, on July 1, 2015, the NRC discussed with Mr. S. Marik of your staff the preliminary White determination for the finding discussed below.

The enclosed inspection report discusses a finding that has preliminarily been determined to be a White finding with low-to-moderate safety significance that may require additional inspections, regulatory actions, and oversight. Specifically, increased vibrations experienced on Dresden Unit 2 main steam line piping while operating at extended power uprate (EPU) power levels resulted in the degradation of multiple electromatic relief valve (ERV) actuator subcomponents that rendered the 2C relief valve inoperable. This finding does not represent an immediate safety concern in that you replaced all four Unit 2 ERV actuators in February 2015 with a hardened design successfully utilized in the industry at other boiling water reactor plants which have also experienced significant steam line vibrations post EPU.

This finding was assessed based on the best available information, using the NRC's significance determination process (SDP). The basis for the NRC's preliminary significance determination is described in the enclosed report. The NRC will inform you in writing when the final significance has been determined.

The finding is also an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the Enforcement Policy, which appears on the NRC's Web site at http://www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol.html.

We intend to complete and issue our final safety significance determination within 90 days from the date of this letter. The NRC's SDP is designed to encourage an open dialogue between your staff and the NRC; however, the dialogue should not affect the timeliness of our final determination.

Before the NRC makes a final decision on this matter, you may choose to: (1) attend a Regulatory Conference, where you can present to the NRC your point of view on the facts and assumptions used to arrive at the finding and assess its significance, or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of your receipt of this letter. We encourage you to submit supporting documentation at least 1 week prior to the conference in an effort to make the conference more efficient and effective. If you choose to attend a Regulatory Conference, it will be open for public observation. The NRC will issue a public meeting notice and press release to announce the conference. If you decide to submit only a written response, it should be sent to the NRC within 30 days of your receipt of this letter. If you choose not to request a Regulatory Conference or to submit a written response, you will not be allowed to appeal the NRC's final significance determination.

Please contact Mr. Jamnes Cameron at (630) 829-9833, and in writing, within 10 days from the issue date of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision.

Because the NRC has not made a final determination in this matter, no notice of violation is being issued for this inspection finding at this time. In addition, please be advised that the number and characterization of the apparent violation may change based on further NRC review.

This report also documents three additional findings of very-low safety significance (Green). One of the findings involved a violation of NRC requirements. Additionally, a licensee-identified violation is listed in Section 4OA7 of this report. However, because of their very-low safety significance, and because the issues were entered into your Corrective Action Program, the NRC is treating the issues as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of the NCV(s), 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, DC 20555-0001, with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Dresden Nuclear Power Station.

In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, or the finding not associated with a regulatory requirement, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Dresden Nuclear Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, "Public Inspections, Exemptions, Requests for Withholding," of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC's Public Document Room or from the Publicly Available Records (PARS) component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Anne T. Boland, Director
Division of Reactor Projects

Docket Nos. 50–237, 50–249; 72–037
License Nos. DPR–19; DPR–25

Enclosure:
IR 05000237/2015002; 05000249/2015002; 07200037/2015001
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000237; 05000249; 072000237
License Nos:	DPR–19; DPR–25
Report No:	05000237/2015002; 05000249/2015002; 07200037/2015001
Licensee:	Exelon Generation Company, LLC
Facility:	Dresden Nuclear Power Station, Units 2 and 3
Location:	Morris, IL
Dates:	April 1, 2015, through June 30, 2015
Inspectors:	G. Roach, Senior Resident Inspector D. Lords, Resident Inspector M. Ziolkowski, Acting Resident Inspector M. Bielby, Senior Operations Inspector/Examiner T. Go, Health Physicist M. Learn, Reactor Engineer, MCID, DNMS M. Porfirio, Resident Inspector, Illinois Emergency Management Agency
Observers:	J. Vinyard, Student Engineer M. Caddell, Student Engineer
Approved by:	Anne T. Boland, Director Division of Reactor Projects

Enclosure

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SUMMARY

Inspection Report 05000237/2015002, 05000249/2015002; 04/01/2015 – 06/30/2015; Dresden Nuclear Power Station, Units 2 and 3; Maintenance Risk Assessments and Emergent Work Control, Surveillance Testing, Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors, and announced baseline inspections by regional inspectors. Four findings (FINs) were identified by the inspectors. One of these findings was considered an apparent violation of U.S. Nuclear Regulatory Commission (NRC) regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red), and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," Revision 5, dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very-low safety significance (Green) was self-revealed on January 13, 2015, and again on February 6, 2015, when a loss of power to the Unit 2 feedwater level control (FWLC) system resulted in a reactor scram. The loss in power to the Unit 2 FWLC system was determined to be the result of a human performance error during the original installation of the system under Work Order (WO) 97102835, in that two spade-lug connections associated with the system's +5 Vdc power supply were not properly landed resulting in the intermittent losses in power, and reset of the FWLC system. In addition, a dual in-line package switch on a FWLC Input/Output card was improperly positioned which led to an improper anti-cavitation reactor recirculation pump runback during both events.

  The inspectors determined that the failure to properly land the leads associated with the Unit 2 FWLC system +5 Vdc power supply in accordance with the work instructions in WO 97102835 was a performance deficiency that was determined to be more than minor, and thus a finding, because it was associated with the configuration control attribute of the Initiating Events cornerstone, and affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was determined to be of very-low safety significance (Green), because the inspectors answered "No" to the screening question, "Did the finding cause a reactor trip AND the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition (e.g., loss off condenser, loss of feedwater)?" This finding was determined to have a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because the licensee did not thoroughly evaluate repetitive alarms and a failure of the FWLC system to ensure that resolutions addressed causes and extent of condition prior to restart following the January 13, 2015, FWLC failure and reactor scram. Specifically, licensee analysis of alarms received prior to the January 13, 2015, scram and troubleshooting of the FLWC system failure on January 13, 2015, was overly focused on multi-functional processor cards which happened to be approaching their

end of expected life. Activities to investigate loose wiring connections following the January 13, 2015, scram failed to identify the incorrectly landed spade-lug connections for the +5 Vdc power supply. [P.2] (Section 4OA3.1)

Cornerstone: Mitigating Systems

- Green. A finding of very-low safety significance (Green) was self-revealed on April 21, 2015 while performing TS Surveillance DOS 6600-12, “Diesel Generator Tests: Endurance and Margin/Full Load Rejection/ECCS [Emergency Core Cooling System]/Hot Restart,” in support of Surveillance Requirement 3.8.1.16 which requires the EDG to achieve rated frequency and voltage conditions within 13 seconds when started less than or equal to five minutes from a previously loaded run, the Unit 2 Emergency Diesel Generator (EDG) failed to complete a hot restart. Licensee troubleshooting identified a degraded pressure switch associated with main bearing lube oil pressure in the start circuit which was taking several minutes to return to a low-pressure condition upon shutting down the EDG. This resulted in a failure of the start circuit relay to be energized upon initiating a start of the EDG, until the pressure switch returned to its appropriate low-pressure state. An internal investigation of the pressure switch identified strips of Teflon tape in the bellows of the pressure switch, which resulted in the pressure switch’s sluggish response to lowering lube oil pressure, and a failure to meet the TS hot restart criteria.

  The inspectors determined that the failure to implement Procedure MA–AA–716-008, “Foreign Material Exclusion Program,” and therefore the inability to perform TS Surveillance Requirement 3.8.1.16 was a performance deficiency, and was considered more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone, and impacted the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors utilized Attachment 0609.04, “Initial Characterization of Findings,” and determined that this issue was of very-low safety significance because each question provided in Inspection Manual Chapter (IMC) 0609, Appendix A, Exhibit 2, “Mitigating Systems Screening Questions,” was answered “No.” The inspectors concluded that this finding was cross-cutting in the Human Performance, Documentation area, because licensee procedure MA-AA–716-008, “Foreign Material Exclusion Program,” work instructions associated with Work Order 01410972-01, and previous calibrations of pressure switch 2-6641-526 did not include specific instructions and warnings regarding the proper use of Teflon tape with regards to preventing it from becoming foreign material. Other Dresden maintenance procedures, specifically MA-DR-0300-001, “Preventive Maintenance of Hydraulic Control Unit,” and DEP 0300-16, “Rebuilding the Unit 2 (3) ASCO Scram Solenoid Pilot Valves,” have specific warnings regarding the proper use and potential for Teflon tape to become foreign material. [H.7] (Section 1R13)

- Green. A finding of very low safety significance (Green), and an associated NCV of TS 5.4.1, “Procedures,” was self-revealed on May 19, 2015, when the 2/3 EDG was made inoperable to Unit 2 due to the incorrect manipulation of a test switch by operations personnel during a TS required surveillance test. Specifically, while the licensee performed procedure DIS 1500-05, “Division I and II Low-Pressure Coolant Injection ECCS Initiation Circuitry Logic System Functional Test,” Step 106 ofChecklist B, operations personnel incorrectly opened test switch TS-159SD2/3 at motor control center 23-1 removing the under-voltage trip associated with the feed breaker for the Division I safety-related 4.16 kV engineered safeguards bus, causing the 2/3 EDG to be inoperable to Unit 2.

The licensee's failure to properly implement steps in the procedure was a performance deficiency that was determined to be more than minor, and thus a finding, because it was associated with the Mitigating Systems Cornerstone Attribute of Configuration Control, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was determined to be of very- low safety significance (Green), because each of the questions provided in IMC 0609, Appendix A, Exhibit 2, "Mitigating Systems Screening Questions," were answered "No." The finding has a cross-cutting aspect in the area of Human Performance, Field Presence, for failing to ensure senior managers applied the appropriate oversight of infrequently performed and first time work activities. Specifically, the licensee field supervisor or another senior operations manager was not present for the switching activities, which led to the configuration control error. In this instance, the surveillance test is infrequently performed (every 24 months), and the activity, which included using a maintenance procedure vice an operating procedure, was a first time evolution for both equipment operators involved. [H.2] (Section 1R22)

- To Be Determined - Preliminary White. A finding preliminarily determined to be of low-to-moderate safety significance, and an associated Apparent Violation of Title 10 of the *Code of Federal Regulations*, Part 50, Appendix B, Criterion III, "Design Control"; TS 3.4.3, "Safety and Relief Valves"; and TS 3.5.1, "ECCS Operating", was self-revealed on February 7, 2015, following the discovery that one of the Unit 2 electromatic relief valves (ERVs) would not have performed its intended safety function. Vibration induced wear experienced while operating at extended power uprate (EPU) power levels resulted in the degradation of multiple ERV actuator subcomponents, which rendered the valve inoperable. This finding does not represent an immediate safety concern in that the licensee has replaced all Unit 2 and 3 ERV actuators with a hardened design successfully utilized at the Quad Cities Nuclear Power Station, which has also experienced significant steam line vibrations post EPU.

  The inspectors determined that the licensee's apparent failure to ensure measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of SSCs, in particular ERV 2-0203-3C (2C), was a performance deficiency warranting a significance evaluation. The finding was determined to be more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone attributes of design control and equipment performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. A Significance and Enforcement Review Panel, using IMC 0609, Appendix A, "Significance Determination Process for Findings At-Power," dated June 19, 2012, preliminarily determined the finding to be of low to moderate safety significance. The inspectors determined that this finding has a cross-cutting aspect of Resolution in the area of Problem Identification and Resolution, since it involves the failure to implement effective corrective actions to address issues in a timely manner commensurate with their safety significance. This cross-cutting issue is conditional depending on the outcome of the preliminary White finding. [P.3] (Section 4OA3.2)

Licensee-Identified Violations

Cornerstone: Public Radiation Safety

- A violation of very-low safety significance which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's Corrective Action Program. This violation and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 2

Unit 2 remained at or near full power for the entire inspection period.

Unit 3

Unit 3 began the inspection period at full power. On May 2, 2015, a short downpower to 96 percent was performed to insert control rod N-05 for repairs. On May 23, 2015, unit output was lowered to 50 percent to perform feedwater regulating valve repairs, scram timing, turbine surveillances and control rod recovery. The unit returned to near full power on May 24, 2015, where it remained for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Off-Site and Alternate Alternating Current Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of off-site and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas, and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the off-site power system. Examples of aspects considered in the inspectors' review included:

- Coordination between the TSO and the plant during off-normal or emergency events;
- Explanations for the events;
- Estimates of when the off-site power system would be returned to a normal state; and
- Notifications from the TSO to the plant when the off-site power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain availability and reliability of both the off-site AC power system, and the on-site alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- Actions to be taken when notified by the TSO that the post-trip voltage of the off-site power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the on-site power supply;

- Compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- Re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide off-site power; and
- Communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed Corrective Action Program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold, and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness of off-site and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01–05.

b. <u>Findings</u>

No findings were identified.

.2 <u>Readiness For Impending Adverse Weather Condition—Severe Weather and Flash Flood Warning</u>

a. <u>Inspection Scope</u>

The inspectors evaluated the design, material condition, and procedures for coping with the expected flooding conditions based on predicted rainfall, and rises in local river and lake levels. The evaluation included a review to check for deviations from the descriptions provided in the Updated Final Safety Analysis Report (UFSAR) for features intended to mitigate the potential for flooding. As part of this evaluation, the inspectors checked for obstructions that could prevent draining, checked that the roofs did not contain obvious loose items that could clog drains in the event of heavy precipitation, and determined that barriers required to mitigate the flood were in place and operable. Additionally, the inspectors performed a walkdown of the protected area to identify any modification to the site, which would inhibit site drainage during the predicted flood conditions or allow water ingress past a barrier. The inspectors also walked down underground bunkers/manholes subject to flooding that contained multiple train or multiple function risk-significant cables. The inspectors also reviewed the abnormal operating procedure and compensatory measures for mitigating the expected flooding conditions to ensure they could be implemented as written. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one readiness for impending adverse weather condition sample as defined in IP 71111.01–05

b. <u>Findings</u>

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- 2B standby liquid control (SBLC) following return to service from work window;
- Unit 2 high-pressure coolant injection (HPCI) during Unit 2 isolation condenser (IC) unavailability and Yellow risk; and
- 3A instrument air train following corrective maintenance to the 3A instrument air compressor.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specification (TS) requirements, outstanding work orders (WOs), condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers, and entered them into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

On June 25, 2015, the inspectors performed a complete system alignment inspection of the HPCI suction to the contaminated condensate storage tank or the torus to satisfy Title 10, *Code of Federal Regulations* (CFR), Part 50, Appendix R, requirements to verify the functional capability of the system. This system was selected because it was considered both safety-significant and risk-significant in the licensee's probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support

systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

These activities constituted one complete system walkdown sample as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns, which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone 6.2, Unit 2/3 computer room and auxiliary electric room, elevation 517';
- Fire Zone 18.7.1, Unit 2/3 IC pump house, north cubicle, elevation 517' and Fire Zone 18.7.2, Unit 2/3 IC pump house, south cubicle, elevation 517';
- Fire Zone 8.2.6E, Unit 3 turbine building, elevation 538', reactor feed pump switchgear and hydrogen seal oil; and
- Fire Zone N/A, Unit 2 station blackout (SBO) switchgear electrical equipment room 3rd floor east, and Fire Zone N/A, Unit 2 SBO diesel generator 2.

The inspectors reviewed areas to assess if the licensee had implemented a Fire Protection Program that adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, maintained passive fire protection features in good material condition, and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the Attachment to this report, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP. Documents reviewed are listed in the Attachment to this report.

These activities constituted four quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On June 9, 2015, the inspectors observed fire brigade activation for an unannounced Unit 3 motor control center (MCC) 39-1 simulated cubical fire. Based on this observation, the inspectors evaluated the readiness of the plant's fire brigade to fight fires. The inspectors verified that the licensee's staff identified deficiencies, openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- Proper wearing of turnout gear and self-contained breathing apparatus;
- Proper use and layout of fire hoses;
- Employment of appropriate firefighting techniques;
- Sufficient firefighting equipment brought to the scene;
- Effectiveness of fire brigade leader communications, command, and control;
- Search for victims and propagation of the fire into other plant areas;
- Smoke removal operations;
- Utilization of pre-planned strategies;
- Adherence to the pre-planned drill scenario; and
- Drill objectives.

Documents reviewed are listed in the Attachment to this report.

These activities constituted one annual fire protection inspection sample as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Underground Vaults

a. Inspection Scope

The inspectors selected underground bunkers/manholes subject to flooding that contained cables whose failure could disable risk-significant equipment. The inspectors determined that the cables were not submerged, that splices were intact, and that appropriate cable support structures were in place. In those areas where dewatering devices were used, such as a sump pump, the device was operable and level alarm circuits were set appropriately to ensure that the cables would not be submerged. In those areas without dewatering devices, the inspectors verified that drainage of the area was available, or that the cables were qualified for submergence conditions. The inspectors also reviewed the licensee's corrective action documents with respect to past submerged cable issues identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following underground bunkers/manholes subject to flooding:

- Switchyard manhole 1;
- SBO manhole 3 North;
- SBO manhole 3 South; and
- Security manhole 1.

Specific documents reviewed during this inspection are listed in the Attachment to this report. This inspection constituted one underground vaults sample as defined in IP 71111.06–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

On May 28, 2015, the inspectors reviewed the overall pass/fail results of the Biennial Written Examination and the Annual Operating Test administered by the licensee from April 15, 2015, through May 22, 2015, as required by 10 CFR 55.59(a). The results were compared to the thresholds established in Inspection Manual Chapter (IMC) 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's Licensed Operator Requalification Training Program to meet the requirements of 10 CFR 55.59. (02.02)

This inspection constituted one annual licensed operator requalification examination results sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On April 22, 2015, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- Licensed operator performance;
- Crew's clarity and formality of communications;
- Ability to take timely actions in the conservative direction;
- Prioritization, interpretation, and verification of annunciator alarms;
- Correct use and implementation of abnormal and emergency procedures;
- Control board manipulations;
- Oversight and direction from supervisors; and
- Ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.3 Resident Inspector Quarterly Observation During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On May 13, 2015, the inspectors observed the operator's response to Unit 3 reactor water clean-up (RWCU) isolation due to a failure in the Division 1 high-energy line break isolation circuitry. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- Licensed operator performance;
- Crew's clarity and formality of communications;
- Ability to take timely actions in the conservative direction;
- Prioritization, interpretation, and verification of annunciator alarms (if applicable);
- Correct use and implementation of procedures;
- Control board (or equipment) manipulations;
- Oversight and direction from supervisors; and
- Ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications (if applicable).

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant systems:

- Unit 2 HPCI; and
- Emergency diesel generators (EDGs).

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems, and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices;
- Identifying and addressing common cause failures;
- Scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- Characterizing system reliability issues for performance;
- Charging unavailability for performance;
- Trending key parameters for condition monitoring;
- Ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- Verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Unit 2 EDG emergent repairs following hot restart test failure;
- Unit 2 on-line risk YELLOW with 2B SBLC out-of-service;
- Unit 3 on-line risk YELLOW when transferring 125 Vdc to alternate battery and back to normal battery; and
- Unit 2 on-line risk YELLOW with Division 1 & 2 low-pressure coolant injection (LPCI) unavailability.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4), and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the

scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst, or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

Documents reviewed during this inspection are listed in the Attachment to this report. These maintenance risk assessments and emergent work control activities constituted four samples as defined in IP 71111.13–05.

b. Findings

Failure to Meet a Technical Specification Surveillance Requirement Due to Foreign Material Left in the Unit 2 EDG Starting Circuit

Introduction: A finding of very-low safety significance (Green) was self-revealed on April 21, 2015, while performing TS Surveillance DOS 6600-12, "Diesel Generator Tests: Endurance and Margin/Full Load Rejection/ECCS [Emergency Core Cooling System]/Hot Restart," in support of Surveillance Requirement 3.8.1.16, which requires the EDG to achieve rated frequency and voltage conditions within 13 seconds when started less than or equal to five minutes from a previously loaded run, the Unit 2 EDG failed to complete a hot restart. Specifically, workers failed to implement the foreign material exclusion (FME) control requirements for a foreign material exclusion area (FMEA) Zone 2 when calibrating pressure switch 2-6641-526, U2 D/G Main Bearing Low Oil Pressure (MB1), most recently in February 2015, and during previous calibrations. The failure to implement the FME control requirements resulted in introducing foreign material into the pressure switch, which resulted in the inability to perform the hot restart test of the Unit 2 EDG on April 21, 2015.

Description: On February 16, 2015, the licensee performed a calibration of Unit 2 EDG pressure switch 2-6641-526, U2 D/G MB1, in accordance with WO 01410972-01, "Dresden 2, 4 Year, Preventative Maintenance, Diesel Generator Engine Pressure Instrument Calibration." The WO 01410972-01 specifically required a FMEA Zone 2 be established in accordance with Procedure MA–AA–716-008, "Foreign Material Exclusion Program," in order to prevent the introduction of foreign material into the diesel generator lubricating oil system during the performance of this calibration. In addition, WO 01410972-01 required that Instrument Maintenance Surveillance Procedure, DIS 6600-03, "Unit 2 Diesel Generator Pressure Switches and Pressure Indicators Calibration," be used in order to perform the calibration of the pressure switch. Licensee Procedure DIS 6600-03, requires, in part, that the diesel main bearing lubricating oil-sensing line flexible tubing be removed from the pressure switch sensing port and that a test instrument be connected to the pressure switch in its place. Following successful calibration of the pressure switch, the test instrument is removed from the sensing port and the diesel main bearing lubricating oil-sensing line is reconnected. During this process, Teflon tape is used on the threaded connection for both the test instrument and the sensing line when they are connected to the pressure switch. Calibration of this pressure switch, which was an original installation component, was performed every 2 years from 1988 to 2007, and has been performed every 4 years since.

On April 21, 2015, during the performance of TS Surveillance, DOS 6600-12, "Diesel Generator Tests: Endurance and Margin/Full Load Rejection/ECCS [Emergency Core Cooling System]/Hot Restart," in support of Surveillance Requirement 3.8.1.16, the

Unit 2 EDG failed to perform a hot restart. The Surveillance Requirement 3.8.1.16 required the associated EDG achieve rated frequency and voltage conditions within 13 seconds when started less than or equal to 5 minutes from a previously loaded run. Licensee troubleshooting identified a degraded pressure switch, 2-6641-526, U2 D/G MB1, associated with main bearing lube oil pressure in the start circuit which was taking 17 minutes to return to a low-pressure condition upon shutting down the EDG. This resulted in a failure of the start circuit relay to be energized upon initiating a restart of the EDG until the pressure switch returned to its appropriate low-pressure state. The licensee's investigation of the pressure switch identified foreign material which turned out to be pieces of Teflon tape in the sensing port. In addition there was an accumulation in the bellows of the pressure switch which resulted in the pressure switch's sluggish response to lowering lube oil pressure and a failure to meet the hot restart portion of the surveillance test.

The licensee's Equipment Apparent Cause Evaluation 2488474-02 for this event, in conjunction with off-site laboratory testing of the pressure switch, confirmed that the pieces of Teflon tape at the sensing port and accumulation of Teflon tape strips in the bellows of the pressure switch caused the sluggish action. This conclusion was based on the quantity and the state of the material, which appeared to have deposited over time as the connection from the pressure switch sensing port to the lubricating oil sensing line was disturbed and new Teflon tape was applied.

Bench testing of the pressure switch indicated that the Unit 2 EDG would have been inoperable for 17 minutes following an engine run until the pressure switch would have sensed a low-pressure condition in the diesel lubricating oil system. A review of the records confirmed that the Unit 2 EDG had operated properly during all previous hot restart TS Surveillance tests. Corrective actions for this issue included replacing pressure switch 2-6641-526, removing and inspecting the equivalent pressure switches on the 2/3 and Unit 3 EDGs, reviewing maintenance training with regards to the proper application of Teflon tape, developing a modification using compression fittings at the interface of the pressure switch, and the lube oil system sensing line in order to eliminate the need for Teflon tape, and performing an engineering review and evaluation of unrecovered foreign material for the EDGs. The licensee entered this issue into their corrective action program as IR 2490022.

Analysis: The inspectors determined that the failure to properly implement MA-AA-716-008, as required in WO 01410972-01, which resulted in the unsuccessful completion of TS Surveillance 3.8.1.16 was a performance deficiency warranting further review. The performance deficiency was determined to be more than minor, and thus a finding, in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone Attribute of equipment performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors determined the finding could be evaluated using the Significance Determination Process in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, dated June 19, 2012. The inspectors reviewed the Mitigating Systems Screening Questions in Appendix A, Exhibit 2, and answered "no" to all questions. As a result, the finding was determined to be of very-low safety significance (Green).

The inspectors concluded that this finding had a cross-cutting aspect in the Human Performance, Documentation, area because the FME Program procedure, MA-AA–716-008, work instructions associated with WO 01410972-01, and previous calibrations of pressure switch 2-6641-526 did not include specific instructions and warnings regarding the proper use of Teflon tape with regards to preventing it from becoming foreign material. Other Dresden maintenance procedures, specifically MA-DR-0300-001, "Preventive Maintenance of Hydraulic Control Unit," and DEP 0300-16, "Rebuilding the Unit 2 (3) ASCO Scram Solenoid Pilot Valves," have specific warnings regarding the proper use and potential for Teflon tape to become foreign material. [H.7]

Enforcement: This finding does not involve enforcement action since no violation of a regulatory requirement was identified. Because the finding does not involve a violation, and is of very-low safety significance, it is identified as a finding (FIN). **(FIN 05000237/2015002–01; 05000249/2015002-01: Failure to Meet a Technical Specification Surveillance Requirement Due to Foreign Material Left in the Unit 2 EDG Starting Circuit)**

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- IR 2449137, "2C Emergency Relief Valve Failed to Operate, Historical Operability Review";
- Engineering Change 401652, Revision 000, "Evaluation of Elevated Vibration Readings on U3 HPCI Aux Oil Pump Motor";
- Unit 3 diesel generator cooling water pump flow instrument out of calibration;
- Unit 3 containment cooling service water (CCSW) through-wall leak on Division I CCSW pump suction piping 3-1512-24; and
- Assessment of Operator Work Around (OWA) Control.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the OWAs on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of OWAs. The documents listed in the Attachment to this report were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified OWAs. The inspectors attended the licensee's quarterly OWA board to observe how potential OWA were reviewed and dispositioned by the licensee.

This operability inspection constituted four samples and one OWA sample as defined in IP 71111.15–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance (PM) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 EDG following repair of the start relay circuit;
- Division 2 SBO diesel generator following maintenance window;
- Unit 3 IC valve timing (valves 3-1301-17 & 20) following maintenance window; and
- Trash rake operation following emergent repairs concurrent with low 2/3 crib house intake level due to significant debris buildup following severe weather.

These activities were selected based upon the SSC's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): (1) the effect of testing on the plant had been adequately addressed; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and demonstrated

operational readiness; (4) test instrumentation was appropriate; (5) tests were performed as written in accordance with properly reviewed and approved procedures; (6) equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); (7) and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee's procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with PM tests to determine whether the licensee was identifying problems and entering them in the CAP, and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the Attachment to this report.

This inspection constituted four PM testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function, and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- WO 1659474, "2A SBLC system comprehensive test";
- DOS 1500-10, "LPCI System Pump Operability and Quarterly Test with Torus Available and In-Service Testing (IST) Program," Revision 69 (Routine);
- WO 1815850, "Evaluation of Recent U3 1A MSIV [main steam isolation valve] Closure Testing" (Routine);
- WO 1588967, "D2/3 24M TS Secondary Containment Leak Rate Test" (Routine); and
- DIS 1500-05, "Unit 2, 24 Month LPCI System Logic Functional Surveillance" (Routine).

The inspectors observed in-plant activities and reviewed procedures, and associated records to determine the following:

- Did preconditioning occur;
- The effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- Acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- Plant equipment calibration was correct, accurate, and properly documented;
- As-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;

- Measuring and test equipment calibration was current;
- Test equipment was used within the required range and accuracy; applicable Prerequisites described in the test procedures were satisfied;
- Test frequencies met TS requirements to demonstrate operability and reliability;
- Tests were performed in accordance with the test procedures and other applicable procedures; jumpers and lifted leads were controlled and restored where used;
- Test data and results were accurate, complete, within limits, and valid;
- Test equipment was removed after testing;
- Where applicable for IST activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers code, and reference values were consistent with the system design basis;
- Where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- Where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure;
- Where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished;
- Prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test;
- Equipment was returned to a position or status required to support the performance of its safety functions; and
- All problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the Attachment to this report.

This inspection constituted four routine surveillance testing samples, and one IST sample inspection sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

Inadvertent Manipulation of a Test Switch at Engineered Safety Feature Bus 23-1 during Surveillance Testing Results in the Inoperability of the 2/3 Emergency Diesel Generator to Unit 2

Introduction: A finding of very-low safety significance (Green), and an associated NCV of TS 5.4.1, "Procedures," was self-revealed on May 19, 2015, when the 2/3 EDG was made inoperable to Unit 2 due to the incorrect manipulation of a test switch by operations personnel during a TS required surveillance test. Specifically, while the licensee performed procedure DIS 1500-05, "Division I & II LPCI ECCS Initiation Circuitry Logic System Functional Test," Step 106 of Checklist B, operations personnel incorrectly opened test switch TS-159SD2/3 at MCC 23-1 removing the under voltage trip associated with the feed breaker for the Division I safety-related 4.16 kV engineered safeguards bus, causing the 2/3 EDG to be inoperable to Unit 2.

Description: On May 19, 2015, during the performance of procedure DIS 1500-05, "Division I & II LPCI ECCS Initiation Circuitry Logic System Functional Test," Step 106 of Checklist B, operations personnel incorrectly opened contacts 19 & 20 for test switch TS-159SD2/3 at MCC 23-1, cubical 13. In Step 106, of Checklist B, requires operators

to open contacts 19 & 20 for test switch TS-127B231X which is also located at MCC 23-1, cubical 13. This error was self-revealed to instrument maintenance technicians performing the surveillance in Auxiliary Electrical Equipment Room cabinet 902-32 when relay 1530-102 (BF) did not drop out as expected per Step 108, of Checklist B. Procedural Step 106, of Checklist B, required the operators to utilize concurrent verification to determine the appropriate switch to open.

According to the licensee's apparent cause evaluation (ACE) 2502695-04, the operators failed to utilize appropriate human performance tools and multiple indications to verify the correct test switch was opened. Specifically, neither operator correctly utilized the self-check technique of Stop, Think, Act, Review in accordance with OP-AA-101-113, "Operations Fundamentals of Precisely Controlling Plant Evolutions." while performing their concurrent verification.

Once the operators and maintenance technicians realized that the incorrect test switch was manipulated, the Field Supervisor was dispatched to MCC 23-1 where the Field Supervisor verified that the incorrect test switch had indeed been manipulated. Manipulation of the TS-159SD2/3 contacts 19 & 20 resulted in the removal of the under voltage trip for the feed breaker associated with Bus 23-1 therefore causing the 2/3 EDG to be inoperable to Unit 2.

Analysis: The inspectors determined that the failure to properly implement the steps in DIS 1500-05 (WO 01614824-01) was contrary to the requirements of TS 5.4.1, "Procedures," and was a performance deficiency warranting further review. The performance deficiency was determined to be more than minor, and thus a finding, in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone Attribute of Configuration Control, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 2, dated June 19, 2012. The inspectors reviewed the Mitigating Systems Screening Questions in Appendix A, Exhibit 2 and answered "no" to all questions. As a result, the finding was determined to be of very-low safety significance (Green).

This finding has a cross-cutting aspect in the area of Human Performance, Field Presence, for failing to ensure senior managers applied the appropriate oversight of infrequently performed and first time work activities. Specifically, the licensee field supervisor or another senior operations manager was not present for the switching activities which led to the configuration control error. In this instance, the surveillance test in question is infrequently performed (every 24 months) and the activity, which included using a maintenance procedure vice an operating procedure, was a first time evolution for both equipment operators involved. [H.2]

Enforcement: Technical Specification 5.4.1 states, in part, that "written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978."
In NRC Regulatory Guide 1.33, Appendix A, Section 8b, states, in part, that procedures for surveillance tests, inspections and calibrations should be written to perform ECCS

tests. Licensee procedure DIS 1500-05 “Division I & II LPCI ECCS Initiation Circuitry Logic System Functional Test”, was written in accordance with RG 1.33. ECCS surveillance testing was being performed for the Unit 2, Division I LPCI in accordance with procedure DIS 1500-05.

Contrary to the above, on May 19, 2015, while performing the Unit 2, Division I LPCI logic system functional test, the licensee failed to implement Checklist B step 106 of procedure DIS 1500-05. Specifically, operations personnel incorrectly opened test switch TS-159SD2/3 at MCC 23-1 removing the under voltage trip associated with the feed breaker for the Division I safety-related 4.16 kV engineered safeguards bus. This resulted in the Unit 2/3 EDG becoming inoperable. Following the incorrect switch manipulation, the licensee stopped the surveillance test, reviewed system drawings and procedures, and developed a proceduralized approach to restoring the configuration of the engineered safety feature (ESF) Bus 23-1 under voltage circuit and, thereby, restored 2/3 EDG operability to Unit 2. The licensee initiated actions to review the proper technique for performing a concurrent verification with all operations crews and conducted an ACE 2502695-04. The issue was entered into the licensee’s CAP as IR 2502695.

Because this violation was of very-low safety significance, and it was entered into the licensee’s CAP (IR 2502695), this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (**NCV 05000237/2015002-02, Inadvertent Manipulation of a Test Switch at ESF Bus 23-1 During Surveillance Testing Results in the Inoperability of the 2/3 EDG to Unit 2**).

1EP6 Drill Evaluation (71114.06)

.1 Training Observation

a. Inspection Scope

The inspectors observed a simulator training evolution for licensed operators on April 22, 2015, which required emergency plan implementation by a licensee operations crew. This evolution was planned to be evaluated and included in performance indicator data regarding drill and exercise performance. The inspectors observed event classification and notification activities performed by the crew. The inspectors also attended the post-evolution critique for the scenario. The focus of the inspectors’ activities was to note any weaknesses and deficiencies in the crew’s performance and ensure that the licensee evaluators noted the same issues and entered them into the CAP. As part of the inspection, the inspectors reviewed the scenario package and other documents listed in the Attachment to this report.

This inspection of the licensee’s training evolution with emergency preparedness drill aspects constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS7 Radiological Environmental Monitoring Program (71124.07)

This inspection constituted a partial sample as defined in Inspection Procedure 71124.07-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the Annual Radiological Environmental Operating Reports, and the results of any licensee assessments since the last inspection to assess whether the Radiological Environmental Monitoring Program (REMP) was implemented in accordance with the Technical Specifications (TSs) and Offsite Dose Calculation Manual (ODCM). This review included reported changes to the ODCM with respect to environmental monitoring, commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, Inter-Laboratory Comparison Program, and analysis of data.

The inspectors reviewed the ODCM to identify locations of environmental monitoring stations.

The inspectors reviewed the Final Safety Analysis Report (FSAR), for information regarding the Environmental Monitoring Program, and meteorological monitoring instrumentation.

The inspectors reviewed quality assurance audit results of the program to assist in choosing inspection “smart samples.” The inspectors also reviewed audits and technical evaluations performed on the vendor laboratory if used.

The inspectors reviewed the Annual Effluent Release Report and the Title 10, *Code of Federal Regulations* (CFR), Part 61, “Licensing Requirements for Land Disposal of Radioactive Waste,” report, to determine if the licensee was sampling, as appropriate, for the predominant and dose-causing radionuclides likely to be released in effluents.

b. Findings

No findings were identified.

.2 Site Inspection (02.02)

a. Inspection Scope

The inspectors walked down select air sampling stations and dosimeter monitoring stations to determine whether they were located as described in the ODCM, and to determine the equipment material condition. Consistent with smart sampling, the air sampling stations were selected based on the locations with the highest X/Q, D/Q wind sectors, and dosimeters were selected based on the most risk-significant locations (e.g., those that have the highest potential for public dose impact).

For the air samplers and dosimeters selected, the inspectors reviewed the calibration and maintenance records to evaluate whether they demonstrated adequate operability of these components. Additionally, the review included the calibration and maintenance records of select composite water samplers.

The inspectors observed the collection and preparation of environmental samples from different environmental media (e.g., ground and surface water, milk, vegetation, sediment, and soil) as available to determine if environmental sampling was representative of the release pathways as specified in the ODCM, and if sampling techniques were in accordance with procedures.

Based on direct observation and review of records, the inspectors assessed whether the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the FSAR, U.S. Nuclear Regulatory Commission Regulatory Guide 1.23, "Meteorological Monitoring Programs for Nuclear Power Plants," and licensee procedures. The inspectors assessed whether the meteorological data readout and recording instruments in the control room and, if applicable, at the tower were operable.

The inspectors evaluated whether missed and/or anomalous environmental samples were identified and reported in the Annual Environmental Monitoring Report. The inspectors selected events that involved a missed sample, inoperable sampler, lost dosimeter, or anomalous measurement to determine if the licensee had identified the cause and had implemented corrective actions. The inspectors reviewed the licensee's assessment of any positive sample results (i.e., licensed radioactive material detected above the lower limits of detection), and reviewed the associated radioactive effluent release data that was the source of the released material.

The inspectors selected structures, systems, and components (SSCs) that involve or could reasonably involve licensed material for which there is a credible mechanism for licensed material to reach ground water, and assessed whether the licensee had implemented a sampling and monitoring program sufficient to detect leakage of these SSCs to ground water.

The inspectors evaluated whether records, as required by 10 CFR 50.75(g), of leaks, spills, and remediation since the previous inspection were retained in a retrievable manner.

The inspectors reviewed any significant changes made by the licensee to the ODCM as the result of changes to the land census, long-term meteorological conditions (3-year average), or modifications to the sampler stations since the last inspection. They reviewed technical justifications for any changed sampling locations to evaluate whether the licensee performed the reviews required to ensure that the changes did not affect its ability to monitor the impacts of radioactive effluent releases on the environment.

The inspectors assessed whether the appropriate detection sensitivities with respect to TSs/ODCM where used for counting samples (i.e., the samples meet the TSs/ODCM required lower limits of detection). The licensee uses a vendor laboratory to analyze the REMP samples so the inspectors reviewed the results of the vendor's Quality Control Program, including the inter-laboratory comparison, to assess the adequacy of the vendor's program.

The inspectors reviewed the results of the licensee's Inter-Laboratory Comparison Program to evaluate the adequacy of environmental sample analyses performed by the licensee. The inspectors assessed whether the inter-laboratory comparison test included the media/nuclide mix appropriate for the facility. If applicable, the inspectors reviewed the licensee's determination of any bias to the data and the overall effect on the REMP.

b. Findings

No findings were identified.

.3 Identification and Resolution of Problems (02.03)

a. Inspection Scope

The inspectors assessed whether problems associated with REMP were being identified by the licensee at an appropriate threshold, and were properly addressed for resolution in the licensee's CAP. Additionally, they assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involved the REMP.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index - Emergency Alternating Current Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency Alternating Current (AC) Power System performance indicator (PI) (MS06) for Dresden Nuclear Power Station, Units 2 and 3, covering the period from the second quarter 2014 through first quarter 2015. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, issue reports, event reports and U.S. Nuclear Regulatory Commission (NRC) Integrated Inspection Reports (IRs) for the period of April 2014 through March 2015, to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index—High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index – High-Pressure Injection Systems performance indicator (MS07) for Dresden Nuclear Power Station, Units 2 and 3, covering the period from the second quarter 2014 through first quarter 2015. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee's operator narrative logs, issue reports, MSPI derivation reports, event reports, and NRC Integrated IRs for the period of April 2014 through March 2015 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, that the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator, and none were identified. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two MSPI high-pressure injection system samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Exposure Control Effectiveness PI for the period from the first quarter 2014 through the first quarter 2015. The inspectors used PI definitions and guidance contained in the NEI Document 99 02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 2013, to determine the accuracy of the PI data reported during those periods. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff, the scope and breadth of its data review and the results of those reviews. The inspectors independently reviewed electronic personal dosimetry dose rate and accumulated dose alarms, and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of numerous locked high and very-high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one occupational exposure control effectiveness sample as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities, and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: (1) identification of the problem was complete and accurate; (2) timeliness was commensurate with the safety significance; (3) evaluation and disposition of performance issues, (4) generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; (5) and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment to this report.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Semi-Annual Trend Review: Foreign Material Exclusion Program

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspectors CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of January 1 through June 30, 2015, although examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or reworks maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and maintenance rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted a single semi-annual trend inspection sample as defined in IP 71152–05.

Observations

On January 8, 2015, a Dresden, Unit 3, fuel failure was declared based upon the results of chemistry samples taken over the course of 3 days consistently indicating a fuel failure. By licensee procedure, the sample results met Action Level 1 criteria (one or more fuel failures with little fission product release) for the confirmed failure due to Xenon-133 greater-than two times the steady state full power activity. The licensee's failed fuel monitoring team characterized the failure as a small pin-hole type failure of one fuel rod of a Westinghouse fuel bundle. On January 30, after power suppression testing the licensee fully inserted a control rod for defect power suppression.

The licensee performed a failure mode and effects analysis, and determined the failure to be located in one of four fuel bundles. The analysis concluded that debris fretting due to foreign material intrusion was the only high-probability failure mode; no other possible failure mode was considered to be any higher than a low-probability. The foreign material was most likely introduced into the reactor coolant system during the recent Unit 3 refueling outage from November 3 – November 19, 2014. Following the licensee's failure analysis the station recognized a need to stress the Foreign Material Exclusion (FME) Program to outage workers, and ensure proper program implementation.

Since the fuel failure was identified the licensee has implemented a failed fuel monitoring plan in order to trend key fuel reliability parameters such as off-gas system radiation, off-gas flux tilt radiation, off-gas chemistry pretreatment samples, and reactor coolant

chemistry samples. Since the insertion of a control rod for defect power suppression the trend of these parameters have not indicated any significant failure degradation. Weekly meetings of the Failed Fuel Monitoring Team have appropriately discussed, and addressed any observed variations in these parameters and are mindful of further corrective actions necessary should the condition of the fuel defect degrade. The licensee's team is also consistently well informed of other plant conditions, which may influence the fuel failure such as a potential unit shutdown or increased reactor coolant system flow.

On June 15, in Issue Report 2514759, the licensee documented an observed negative trend in FME practices. Issue Reports 2488474, 2484766, 2407032, and 2410330 have all documented events where foreign material has been introduced into systems due to poor work practices, and adversely affected the operability and/or functionality of systems such as the U2 emergency diesel generator, U3 drywell equipment drain sump solenoid valve, U3 main turbine bearing, and the 3C1 feedwater heater. Because this adverse trend potentially includes the U3 fuel failure, and the subsequent impact to the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events, this issue will be revisited in a future IR when the cause of the U3 fuel failure can be more conclusively demonstrated.

b. Findings

No findings were identified.

.4 Selected Issue Follow-Up Inspection: Review of Operating Experience Smart Sample: OpESS FY2009–02 "Negative Trend and Recurring Events Involving Feedwater Systems"

a. Inspection Scope

The inspectors selected NRC Operating Experience Smart Sample 2009–02, entitled "Negative Trend and Recurring Events Involving Feedwater Systems," to evaluate the applicability of this issue to Dresden. Specifically, Unit 2 experienced a manual reactor scram due to a high-reactor water level on January 13, 2015, and an automatic reactor scram on February 6, 2015, due to a low-reactor water level both as a result of a failure in the digital feedwater level control (FWLC) system, and an improperly positioned dip switch in the FWLC system interface with the reactor recirculation system logic circuitry. The inspectors reviewed pertinent CAP documents including the licensee's root cause analysis Root Cause Report 2437067-06, "Two Reactor Scrams from a Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback," reviewed FWLC system design documents and maintenance records, and interviewed station personnel regarding these events. In this review, the inspectors evaluated licensee activities to verify compliance with applicable regulations (e.g., Title 10, *Code of Federal Regulations* [CFR], Part 50, Appendix B, §50.65, etc.), and to verify that activities were performed in accordance with station CAP procedures. Documents reviewed are listed in the Attachment to this report.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152–05.

b. Findings

A finding of very-low safety significance (Green) is documented in section 4OA3.1 of this IR.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000237/2015-001-00: Unit 2 Scram Due to Feedwater Level Control Issues, and (Closed) Licensee Event Report 05000237/ 2015-001-01: Unit 2 Scram Due to Feedwater Level Control Issues

a. Inspection Scope

On January 13, 2015, operators manually scrammed Unit 2 due to an increasing reactor water level following a failure of the Unit 2 FWLC system, and a runback of the 'A' reactor recirculation pump. The operators assumed manual FWLC from the main control room, but due to the reactor water level swell following the recirculation pump runback, they were not able to prevent water level from reaching +45 inches at which point all reactor feed pumps (RFPs) would receive a trip signal. Per procedure, operators inserted a manual scram of the reactor prior to receiving the RFP trip.
On February 6, 2015, Unit 2 experienced an automatic scram on low-reactor water level following a failure of the FWLC system, and runback of the 'A' reactor recirculation pump during troubleshooting activities in the FLWC cabinet. With the operators again attempting to maintain reactor level in manual bypass control in conjunction with the recirculation pump runback all three RFP tripped on low-suction pressure resulting in a lowering reactor water level and subsequent automatic scram. These events were reported as Licensee Event Report (LER) in accordance with 10 CFR 50.73(a)(2)(iv)(A), any event or condition that resulted in manual or automatic actuation of any of the systems listed in paragraph (a)(2)(iv)(B).

At the time of submittal of the original LER, the licensee had not completed its causal analysis report. The supplemental LER was issued to include the root causes for both events.

The inspectors reviewed the LERs to determine if the licensee's evaluation and associated corrective actions were appropriate. The inspectors also assessed the accuracy of the LERs, the timeliness of corrective actions, whether additional violations of requirements occurred, and if potential generic issues existed.

Documents reviewed are listed in the Attachment to this report. These two LERs are closed. This event follow-up review constituted two samples as defined in IP 71153–05.

b. Findings

Reactor Scram Due to Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback

Introduction: A finding of very-low safety significance (Green) was self-revealed on January 13, 2015, and again on February 6, 2015, when a loss of power to the Unit 2 FWLC system resulted in a reactor scram. The loss in power to the Unit 2 FWLC system was determined to be the result of a human performance error during the original installation of the system under Work Order (WO) 97102835, in that two spade-lug

connections associated with the system's +5 Vdc power supply were not properly landed resulting in the intermittent losses in power and reset of the FWLC system. In addition, a duel in-line package (DIP) switch on a FWLC Input/Output (I/O) card was improperly positioned which led to the improper anti-cavitation reactor recirculation pump runback during both events.

Description: In 1997, the licensee installed the existing Bailey Infi-90 Digital FWLC system on Unit 2 under WO 97102835. During that installation, the licensee landed the spade-lug connections associated with the +5 Vdc ribbon cable. A review of the WO did not specifically indicate a verification of the connection integrity for this ribbon cable. In addition, a maintenance history for the Bailey FWLC system performed by the licensee, and independently verified by the inspectors, did not indicate any subsequent activity that would have disconnected or manipulated the ribbon cable.

In April 2002, the licensee established a preventative maintenance activity under preventive maintenance identification number (PMID) 163901 to remove and clean FWLC circuit cards on an every refueling outage basis. The preventative maintenance work instructions did not specifically instruct the technician to verify the position of DIP switches on the circuit cards after cleaning and prior to restoration in the system. In addition, the original installation WO did not account for DIP switch positions on the various circuit cards and as such it is not possible to determine when the mispositioning occurred.

On January 30, 2006, Unit 2 main control room (MCR) operators received a feedwater control system trouble alarm. The cause of the alarm was determined to be due to the FWLC system seeing a failure of the back-up Multi-Functional Processor (MFP) card. With vendor support, the licensee replaced the card under WO 887887, and bench tested the removed card. The card performed normally with no failures during post removal testing. On September 4, 2014, MCR operators again received a trouble alarm for a backup MFP bad status. In this instance, the system reset itself and the alarm cleared. A Prompt Investigation (1699697-02) performed by the licensee identified that all indicating lights at FWLC panel 902-18 were in their normal condition for both the main and back-up MFP cards, and that the condition which caused the alarm to occur had cleared leaving no trace of its origin. On October 10, 2014, the same trouble alarm was again received in the MCR. This time the condition did not clear and again a backup MFP bad status was received and remained locked in. With vendor (ABB) oversight, the licensee reset the condition and the alarm cleared on October 11, 2014. Based on the age of the MFP cards installed in the system (the primary card was installed in 2005, and the back-up as mentioned above was installed in 2006), and in conjunction with the vendor's recommendation to replace the MFP card's batteries every 10 years, the licensee verified that the cards were slated to be replaced during the next Unit 2 refueling outage in the fall of 2015. With this information, and since the card was able to be reset following instructions in the vendor manual, the licensee took no further actions to address these alarms, and therefore missed an opportunity to question with detailed analysis two failures within a 1 month period.

On January 12, 2015, the trouble alarm was received for the third time since September 2014. Again the alarm would not reset itself, and the vendor was consulted. The vendor recommended card replacement at this point and a date of January 15, 2015 was scheduled as the earliest all required licensee and vendor staff could be on-site to conduct the replacement. On January 13, 2015, at 1835, MCR operators again received

the FWLC system trouble alarm, and at 1903 the primary MFP card failed with the back-up in an already failed condition resulting in a complete loss of the FWLC system. In addition, an anti-cavitation runback to minimum speed of the 2A reactor recirculation pump occurred concurrently with the loss of FWLC. With the perturbations to reactor water level resulting from operators having to control level in manual bypass mode and exacerbated by the reactor water level swell induced by the recirculation pump runback, a manual reactor scram was inserted prior to reactor water level reaching the RFP high-level trip. During the subsequent forced outage, the licensee initiated a troubleshooting and repair plan that included resetting the MFP cards, which was successful. As the licensee and vendor continued to believe that the failures were the result of an early sign of MFP battery degradation, both MFP cards were replaced. In addition, the troubleshooting plan called for inspections to look for loose connections in the FWLC circuitry, but none were identified. No troubleshooting resources were devoted towards determining why the anti-cavitation runback occurred on the 2A reactor recirculation pump. On January 16, 2015, Unit 2 was returned to power operations.

As a part of its post-scram investigation, the licensee sent the removed MFP cards to the vendor for investigation and analysis, and no issues were identified with the cards during bench testing. On January 18, 2015, with the reactor again at full power, the FLWC trouble alarm indicating another back-up MFP bad status was received. The condition reset itself, but it indicated that the fault which had eventually resulted in the recent scram had not been corrected. The licensee with vendor participation, created a complex troubleshooting plan in which a number of potential causes were identified including loose wiring connections and power supply degradation. During the complex troubleshooting process, the licensee determined that the reactor recirculation pump runback could have been caused by a mispositioned DIP switch in the FWLC circuitry. Since the DIP switches are located on cards not normally accessible during FWLC system operation, future actions to investigate the condition of the DIP switches were established by the licensee. On February 6, 2015, following a management challenge review of the troubleshooting plan, the licensee installed a test recorder under WO 1801088 to monitor for noise on the FWLC system's +5 Vdc power supply. During this evolution, technicians noted an unstable voltage at about 4.8 Vdc with an expected value of 5.2 Vdc. Concerned that the test lead was not fully connected, the technicians attempted to more firmly seat the lead which in turn resulted in a feedwater regulating valve lock-up alarm and a loss of the FWLC system. The licensee later identified that power from the +5 Vdc power supply was briefly interrupted when the technician attempted to more firmly seat the test connection, because the opposite end of the ribbon cable from the test point was not properly connected at the spade-lug connection point. A 2A reactor recirculation pump runback occurred with the loss of FWLC, and the operators were again required to take manual bypass control of reactor water level. In this instance, operators were able to turn reactor water level following the level swell but were unable to arrest the downward trend in reactor water level when the RFPs tripped on low-suction pressure, which resulted in Unit 2 experiencing a low-reactor water level automatic scram.

The licensee's root cause report (RCR 2437067), "Two Reactor Scrams from a Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback," identified two root causes for the events: (1) a spurious power interruption on a historically improperly landed power supply ribbon cable connection for the digital FWLC system, and (2) less than rigorous organizational challenge of troubleshooting. The first root cause was associated with both scram events, and the second root cause

was associated with only the February 6, 2015, scram. With regards to the second root cause, the licensee noted that troubleshooting following the first scram was not rigorous, and that potential causes were rationalized, assumptions were not adequately challenged, and less than rigorous organizational challenges were performed because of over-reliance on vendor disposition. The licensee also noted that inadequate questioning attitude and organizational response to alarms in September 2014 and October 2014, a mispositioned DIP switch on a FLWC I/O card, inadequate risk management by the site management team in allowing test recorders to be installed into the FWLC system at full power, and inadequate risk management by the maintenance and operations team who failed to stop when abnormal voltages were seen upon landing test equipment on the +5 Vdc power supply contributed to these events.

As immediate corrective actions, the licensee entered the issue into their CAP as Issue Report 2437067; replaced the affected ribbon cable with 5 individual wires; verified additional Unit 2 FWLC spade-lug connections; visually inspected Unit 3 FWLC spade-lug connections; established an action to verify Unit 3 FLWC connections prior to restart from next outage; corrected Unit 2 DIP switch positioning; and revised PMIDs to document as found and as left DIP switch positions. In addition, the licensee will be conducting training and developing case studies of the events to improve the troubleshooting process; and performing a 100 percent review of complex troubleshooting support/refute matrices either open or closed within the last year.

Analysis: The inspectors determined that while the equipment was not covered under 10 CFR Part 50, Appendix B that the failure to properly land the leads associated with the Unit 2 FWLC system +5 Vdc power supply in accordance with the work instructions in WO 97102835 was a performance deficiency.

The performance deficiency was determined to be more than minor, and thus a finding, in accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the configuration control attribute of the Initiating Events cornerstone, and affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, in this case had the spade-lug leads for the +5 Vdc power supply of the unit 2 FWLC system been correctly landed, the loss of power to FWLC and subsequent reactor level perturbations and resulting reactor scrams would not have occurred.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings," dated June 19, 2012, Table 2 the inspectors determined the finding affected the Initiating Events cornerstone. The inspectors determined the finding could be evaluated using Appendix A, "The Significance Determination Process for Findings At-Power," Exhibit 1, Section B, "Transient Initiators," dated June 19, 2012. The inspectors answered "No" to the screening question, "Did the finding cause a reactor trip AND the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition (e.g. loss off condenser, loss of feedwater)?" and therefore the inspectors determined that the finding was of very-low safety significance (Green).

This finding was determined to have a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because the licensee did not thoroughly evaluate repetitive alarms and a failure of the FWLC system to ensure that resolutions addressed causes and extent of condition prior to restart following the January 13, 2015, FWLC failure and reactor scram. Specifically, licensee analysis of alarms received prior to the January 13, 2015, scram and troubleshooting of the FLWC system failure on January 13, 2015, was overly focused on MFP cards which happened to be approaching their end of expected life. Activities to investigate loose wiring connections following the January 13, 2015, scram failed to identify the incorrectly landed spade-lug connections for the +5 Vdc power supply. [P.2]

Enforcement: This finding does not involve enforcement action since no violation of a regulatory requirement was identified. Because the finding does not involve a violation, and is of very-low safety significance, it is identified as a finding (FIN). (**FIN 05000237/2015002-03, "Reactor Scram Due to Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback"**)

.2 (Closed) Licensee Event Report 05000237/2015-002-00: Unit 2 Electromatic Relief Valve Failed to Actuate During Extent of Condition Testing, and (Closed) Licensee Event Report 05000237/2015-002-01: Unit 2 Electromatic Relief Valve Failed to Actuate During Extent of Condition Testing

a. Inspection Scope

On February 7, 2015, with Unit 2 in mode 4, an electromatic relief valve (ERV) actuator failed to open during the performance of an extent of condition test. The testing involved an operator manually actuating the ERV from the MCR with operators and engineers staged in the field. However, when the demand signal was given, the 2C actuator plunger did not move, and the valve did not open.

At the time of submittal of the original LER, the licensee had not completed its causal analysis report. The supplemental LER was issued to include the root causes for this event, and a previous event associated with the 3E ERV that is referenced in Integrated IR 05000237/2014005; 05000249/2014005.

The inspectors reviewed the LERs to determine whether the licensee's evaluation and associated corrective actions were appropriate. The inspectors also assessed the accuracy of the LERs, the timeliness of corrective actions, whether additional violations of requirements occurred, and whether potential generic issues existed. These LERs are closed.

The documents reviewed are listed in the Attachment to this report. These two LERs are closed. This event follow-up review constituted two samples as defined in IP 71153–05.

b. Findings

Failure to Ensure Continued Operability of Unit 2 Electromatic Relief Valve 2–0203–3C (2C) Following Implementation of Extended Power Uprate Plant Conditions

Introduction: A finding preliminarily determined to be of low to moderate safety significance (White), and an associated Apparent Violation (AV) of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," Technical Specification 3.4.3, "Safety and

Relief Valves," and Technical Specification 3.5.1, "[Emergency Core Cooling System] ECCS Operating," was self-revealed for the licensee's failure to ensure measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of Structures, Systems, and Components (SSCs) in particular the 2C ERV.

Description: On February 7, 2015, the licensee experienced a failure of the 2C ERV with the reactor shutdown in mode 4 during surveillance testing in accordance with licensee procedure DOS 0250-07, "Electromatic Relief Valve Testing with the Reactor Depressurized." During this surveillance, operators in the MCR manually actuate open the ERVs. When attempting to cycle the 2C ERV, the ERV actuator plunger did not move, and therefore the ERV did not reposition open when it was given a demand signal from the MCR. The condition was identified by in-field verification and MCR valve position indication. A field inspection following the failure of the 2C ERV actuator identified the actuator guide posts wore into the guide post bushings creating a shelf. There were no ERV actuations during the previous operating cycle, thus any wear on the actuator subcomponents was caused by vibration of the subcomponents in contact with each other.

The ERV actuator is a solenoid assembly that energizes to reposition the ERV pilot valve. The ERV actuator is normally de-energized during the operating cycle. When an open signal is sent to the ERV actuator, its solenoid energizes causing a plunger to travel downward and contact the strike lever on the pilot valve assembly. The plunger causes the ERV pilot valve to mechanically reposition relieving pressure internal to the ERV main valve causing it to open and direct steam from the main steam system to the torus suppression pool. The ERVs serve as a component of the automatic depressurization system (ADS) designed to depressurize the reactor coolant system (RCS) during certain loss of coolant accidents in order for the low-pressure coolant injection (LPCI) and core spray systems to be able to inject make-up water to the RCS. In addition, the ERVs provide RCS over pressure protection to minimize the likelihood that the main steam safety valve will have to actuate to protect the RCS from over pressurization.

During refueling outage D2R21 in 2009, the licensee performed a main generator rewind on Unit 2 thus permitting its main generator to supply electrical output power sufficient enough for the reactor to operate at full Rated Thermal Power during the entire operating cycle. This upgrade meant that the main steam lines would be operating at full steam flow during the entire 2 year operating cycle, and would be, along with attached components including the ERVs, subject to higher vibrations over longer durations than previously experienced. The licensee sent the failed 2C ERV component to Exelon Power Labs for a failure analysis. Although the mechanical binding that was observed at the time of failure could not be replicated in the laboratory, the analysis identified two potential causes of the mechanical binding: (1) bushing wear, or (2) plunger arm wear. Misalignment caused the spring guide post to be in contact with the upper bushing and resulted in vibration wear on the inner diameter of the bushing. This wear created a lip of metal that was deformed within the bushing which could have caused, or contributed to, binding between the bushing and top edge of the spring guide post. The actuator had measureable material loss on the bushing. The plunger arm exhibited fretting wear due to rubbing between the plunger arms and the frame angle iron. Three ledges were created on the plunger arms that could have caused, or contributed to, binding between the plunger and frame angle iron. Although the Exelon Power Labs report identified the

failure mode as indeterminate due to the inability to replicate the failure, the licensee concluded that the most probable failure mode was binding at the top of the guide post due to a vibration induced wear, similar to a failure mode identified in 2003, and documented in IR 189474.

The licensee performed a RCR 2445040 for the February 7, 2015, failure of the 2C ERV, and concluded that the root cause of the event was weakness in the maintenance procedural guidance to align, determine excessive wear, and characterize the wear of ERV actuator subcomponents. Licensee procedure MA-DR-ME-4-020046 should have contained additional criteria for replacing worn subcomponents. Vendor maintenance guidance, recommended that the ERV bushings should be visually examined for excessive wear and looseness. Additionally, the guide posts and springs should be visually inspected for excessive wear to verify no ridges, grooves, or burrs exist. The licensee procedure also did not provide necessary guidance for alignment of the guide posts relative to the bushings during reassembly of the actuator following inspection or part replacement. The licensee procedure stated that “If guide post or spring is badly worn or damaged, replace parts as necessary.” The licensee concluded that the subjective acceptance criteria for subcomponent wear resulted in maintenance technicians relying upon skill of the craft to make a decision whether a part should be replaced. The licensee procedure also did not provide the necessary guidance to document a detailed characterization of vibration induced wear of ERV actuators identified during as-found inspections. The procedure required the licensee to “Document initial as-found conditions of guide posts” with no other detail or trending requirement provided. The licensee entered the above recommendations and suggested changes into their corrective action system.

Analysis: The inspectors determined that the licensee’s failure to ensure the continued operability of the Unit 2 ERVs following the establishment of EPU plant operating conditions was a performance deficiency warranting a significance evaluation. The inspectors determined the finding was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” dated September 7, 2012, because it was associated with the Mitigating Systems Cornerstone attributes of design control and equipment performance, and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP) in accordance with IMC 0609, “Significance Determination Process,” Attachment 0609.04, “Initial Characterization of Findings,” dated June 19, 2012, and Appendix A, “The Significance Determination Process for Findings At-Power,” Exhibit 2, “Mitigating Systems Screening Questions,” dated June 19, 2012. The finding represented an actual loss of system safety function of an ERV for greater than its TS 3.4.3.A, and TS 3.5.1.H allowed outage time of 14 days. Therefore, a detailed risk evaluation was performed in accordance with IMC 0609, Appendix A.

The inspectors determined that this finding has a cross-cutting aspect of Resolution in the area of Problem Identification and Resolution, since it involves the failure to implement effective corrective actions to address issues in a timely manner commensurate with their safety significance. This cross-cutting issue is conditional depending on the outcome of the preliminary White finding. [P.3]

Detailed Risk Evaluation

The Senior Reactor Analysts (SRAs) evaluated the finding using the Dresden Standardized Plant Analysis Risk (SPAR) model version 8.21, Systems Analysis Programs for Hands-on Integrated Reliability Evaluations (SAPHIRE) version 8.1.2.0.

Dresden Standardized Plant Analysis Risk Modifications

The SRAs used a change set to model the failure of 2C ERV to open. The basic event representing 2C ERV failing to open was set to TRUE.

The following SPAR Model modifications were made with the assistance of Idaho National Laboratory (INL):

a. A change was made to the success criterion for the number of safety relief valves (SRVs) (i.e., the four ERVs and the Target Rock SRV) required for RCS depressurization following an Anticipated Transient Without Scram (ATWS). The present SPAR model success criterion is 5–of–5 SRVs for RCS depressurization following an ATWS. The licensee's probabilistic risk assessment (PRA) success criterion is 3–of–5 SRVs (based on plant-specific MAAP calculations). The SPAR model was modified to use a 4–of–5 success criterion for RCS depressurization (in fault tree DEP01). Though relaxed from the present 5–of–5 success criterion, the use of a more conservative 4–of–5 SRVs for successful manual RCS depressurization in the SPAR model instead of 3–of–5 SRVs (that the licensee uses) accounts for the licensee's analysis that 12–of–13 SRVs/safety valves are required for success to prevent RCS over-pressurization following an ATWS condition.

   In addition to fault tree DEP01, the RCS depressurization logic found in fault trees DEP, DEP02, LI–DEP, and PPR was modified. The success criteria used is:

   - 2–of–5 SRVs for non-ATWS RCS depressurization (in fault trees DEP, DEP02, and LI–DEP). The success criteria for these fault trees were changed to make them consistent with each other for non-ATWS RCS depressurization.
   - 4–of–5 SRVs during RCS depressurization following an ATWS (in fault tree DEP01) as described above.
   - 4–of–5 SRVs for ATWS over-pressurization (in fault tree PPR) to account for the licensee's analysis that 12–of–13 SRVs/safety valves are required to prevent RCS over-pressurization following an ATWS condition.

b. A new fault tree (DEP-CND) was created to account for successful RCS depressurization when either condenser operation is successful or there is successful operation of at least 2–of–5 SRVs.

c. All the ADS valve common cause failure (CCF) probabilities were changed as a result of modeling that reflects the ADS valves as they are actually tested; that is, in a "non-staggered" fashion over time (i.e., all at once during refueling outages). Also, the new Risk Assessment Standardization Project (RASP) CCF "R" calculation type was used to calculate the CCF probabilities for these valves

based on INL's recommendation. Use of the "R" type calculation for the CCF probabilities is more accurate since it removes approximations when setting the failure mode of the valves in SAPHIRE to "1," "True", "0", or "False."

d. The common-cause group (CCG) for the SRVs was changed from a five-element CCG (that included the 4 ERVs and the Target Rock SRV) to a four-element CCG for the four ERVs (and with the Target Rock SRV separate). This is consistent with the licensee's PRA model and is based on the differences between the ERVs and the Target Rock SRV in (1) valve design, (2) valve relief capacities, and (3) valve actuation mechanisms.

e. Updated CCF basic events for the ERVs were used in the analysis. In the SPAR models, "alpha factors" are used to estimate the conditional CCF probabilities. The "alpha factors" for the ERVs were re-calculated by INL to include data that was more current, such that it included the recent failure of Dresden Unit 3 ERV 3E on November 6, 2014, and two ERV failures at Oyster Creek in 2014. An update of the "alpha factors" for the ERVs based on the latest industry data was judged to provide a more realistic and accurate determination of the delta risk due to the performance deficiency.

<u>**Calculation Discussion**</u>

a. Exposure Time

The exposure time was assumed to be 210 days.

For the last operating cycle, the startup of Unit 2 occurred on November 29, 2013, (following the refueling outage) and the shutdown occurred on February 6, 2015. This gives a total of 434 days. However, there was a Main Power Transformer outage between April 13, 2014, and April 26, 2014, (13 days) during which Unit 2 was in Cold Shutdown. The 2C ERV was not required to be available in Cold Shutdown, and thus the 13 days in Cold Shutdown was subtracted to give 421 days. A "T/2" evaluation provides an exposure time of approximately 210 days (i.e., 421 days divided by 2). The "T/2" exposure time is appropriate based on RASP manual guidance because the time of the actual failure of 2C ERV cannot be determined.

b. Common Cause Failure and Extent of Condition

The CCF potential was assumed. The SRAs used a change set to model common cause failure with the basic event representing failure of 2C ERV to open set to TRUE. This is consistent with current SRA guidance given the circumstances that the failure matches the RASP manual guidance as discussed below:

- RASP manual guidance, Section 5.1 states as "In Scope":

  Treatment of CCF dependencies among components in a Common Cause Component Group (CCCG) given one or more of the following observed conditions:

  - An observed failure of one or more components in a CCCG (i.e., the failure of 2C ERV).

c. Human Reliability

The 2C ERV could not be manually operated, and successful operation of the valve could not be recovered. Thus, setting the failure of 2C ERV to “TRUE” in the SPAR model is a correct modeling for the failure of 2C ERV.

Internal Events Result / Dominant Sequence

The result for the delta internal events core damage frequency ($\Delta CDF_{internal}$) is 1.69E–6/year. The dominant sequence for internal events was a small loss-of-coolant accident (LOCA) initiating event with a failure of the power conversion system, main feedwater, high-pressure coolant injection (HPCI), and the failure of RCS depressurization.

Contributions and Risk Estimates from External Events

FIRES

A rough estimate of the fire risk contribution was obtained using information from the Dresden Individual Plant Examination of External Events (IPEEE), Revision 1, dated February 14, 2000. The following list of fire initiating events was considered in the IPEEE and were the dominant initiating events that contributed to fire risk for this issue.

- Percent TP - Multiple Spurious ADS Valve Opening
- Percent TI - Single Spurious ADS Valve Opening
- Percent TC - Loss of Main Condenser
- Percent LOOP - Single Unit Loss of Off-site Power (LOOP)

The delta risk from each of these fire initiating events is discussed below.

a. Percent TP–Multiple Spurious Automatic Depressurization System Valve Opening

The “Percent TP” initiator is described in the Individual Plant Examination of External Events (IPEEE) as a “Multiple Spurious ADS Valve Opening” initiating event. Based on the Dresden PRA system notebook for the ADS system (i.e., Reactor Vessel Pressure Control and Depressurization ADS System [DR-PSA-005.15 Revision 6]), each ERV can relieve about 540,000 lbm/hr at 1101 psig. This is equivalent to a flowrate of about 1080 gpm. Thus, an opening of two ERVs is equivalent to a break of about 2,000 gpm, and an opening of three ERVs is equivalent to a break of about 3,000 gpm. In NUREG-1829, “Estimating Loss-of-Coolant Accident Frequencies Through the Elicitation Process,” Volume 1, it states that medium LOCAs are historically defined over a flowrate of 1,500 to 5,000 gpm. Thus, the “Percent TP” initiator was modeled as a medium LOCA initiating event in the Dresden SPAR model.

Using the Dresden SPAR model, the Conditional Core Damage Probability (CCDP) of a medium LOCA initiating event with a 2C ERV “Fail-To-Open” failure was 1.85E-3. The nominal CCDP was 7.57E-4 (i.e., medium LOCA with no failure of 2C ERV). Thus, the ΔCCDP is 1.09E-3.

From Table 4-14, “Unit 2 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total ignition frequency (IF) for the “Percent TP” initiating event is 8.48E-4/yr. Using the exposure time (ET) for the finding of 210 days, the ΔCDF for this fire initiating event is:

$\Delta CDF_{\%TP}$ = [IF] x [ΔCCDP] x [ET]
= [8.48E-4/yr] x [1.09E-3] x [210 days/365 days]
= 5.32E-7/yr

b. <u>Percent TI - Single Spurious Automatic Depressurization System Valve Opening</u>

The “Percent TI” initiator is described in the IPEEE as a “Single Spurious ADS Valve Opening” initiating event. The “Percent TI” initiator was modeled as an Inadvertent Open Relief Valve (IORV) initiating event in the Dresden SPAR model. Since the additional equipment failures that would occur for the various affected Fire Compartments are not specified in the IPEEE, the failure of the main feedwater (MFW) system was assumed to provide limiting scenarios based on review of the SPAR model IORV event tree. Using the Dresden SPAR model, the CCDP of an IORV initiating event with loss of MFW and a 2C ERV “Fail-To-Open” failure was 1.22E-3. The nominal CCDP without the 2C ERV “Fail-To-Open” failure was 1.28E-4. Thus, the ΔCCDP is 1.09E-3.

From Table 4-14, “Unit 2 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total IF for the “Percent TI” initiating event is 1.28E-4/yr. Using the ET for the finding of 210 days, the ΔCDF for this fire initiating event is:

$\Delta CDF_{\%TI}$ = [IF] x [ΔCCDP] x [ET]
= [1.28E-4/yr] x [1.09E-3] x [210 days/365 days]
= 8.03E-8/yr

c. <u>Percent TC - Loss of Main Condenser</u>

The “Percent TC” initiator is described in the IPEEE as a “Loss of Condenser” initiating event. Thus, the “Percent TC” initiator was modeled as Loss of Condenser Heat Sink (LOCHS) initiating event in the Dresden SPAR model. Since the additional equipment failures that would occur for the various affected Fire Compartments are not specified in the IPEEE, the failure of the MFW system was assumed to provide limiting scenarios based on review of the SPAR model LOCHS event tree. Using the Dresden SPAR model, the CCDP of an LOCHS initiating event with loss of MFW, and a 2C ERV “Fail-To-Open” failure was 1.95E-5. The nominal CCDP without the 2C ERV “Fail-To-Open” failure was 1.90E-6. Thus, the ΔCCDP is 1.76E-5.

From Table 4-14, “Unit 2 Unscreened Fire Compartment Analysis Details,” of the Dresden IPEEE, the total IF for the “Percent TC” initiating event is 3.41E-2/yr. Using the ET for the finding of 210 days, the ΔCDF for this fire initiating event is:

$\Delta CDF_{\%TC}$ = [IF] x [ΔCCDP] x [ET]
= [3.41E-2/yr] x [1.76E-5] x [210 days/365 days]
= 3.45E-7/yr

d. **Percent LOOP - Single Unit Loss of Offsite Power**

The "Percent LOOP" initiator is described in the IPEEE as a "Single Unit Loss of Offsite Power" initiating event. Thus, the "Percent LOOP" initiator was modeled as a LOOP initiating event with the failure to recover offsite power in the Dresden SPAR model. Using the Dresden SPAR model, the CCDP of a LOOP initiating event with an ERV 2C "Fail-To-Open" failure was 4.94E-5. The nominal CCDP was 1.65E-5 (i.e., with no failure of 2C ERV). Thus, the ΔCCDP is 3.29E-5.

From Table 4-14, "Unit 2 Unscreened Fire Compartment Analysis Details," of the Dresden IPEEE, the total IF for the "Percent LOOP" initiating event is 2.18E-3/yr. Using the ET for the finding of 210 days, the ΔCDF for this fire initiating event is:

$$\begin{aligned}\Delta CDF_{\%LOOP} &= [IF] \times [\Delta CCDP] \times [ET] \\ &= [2.18E\text{-}3/yr] \times [3.29E\text{-}5] \times [210\ days/365\ days] \\ &= 4.13E\text{-}8/yr\end{aligned}$$

Total Estimated Risk From Fires

The total estimated risk from fires is the sum of the risk from the above fire initiating events:

$$\begin{aligned}\Delta CDF_{Fire} &= \Delta CDF_{\%TP} + \Delta CDF_{\%TI} + \Delta CDF_{\%TC} + \Delta CDF_{\%LOOP} \\ &= 5.32E\text{-}7/yr + 8.03E\text{-}8/yr + 3.45E\text{-}7/yr + 4.13E\text{-}8/yr \\ &= 1.0E\text{-}6/yr\end{aligned}$$

FLOODING

Case 1: Internal Plant Flooding - The internal plant flood risk contribution was evaluated as insignificant based on (1) the results from the Dresden Individual Plant Examination Submittal Report, dated January 1993, and (2) a previous version of IMC 0609, Appendix A, Table 3.1, "Plant Specific Flood Scenarios," which showed that there were no significant internal flood scenarios for Dresden Station.

Case 2: External Plant Flooding – The external plant flood risk contribution was evaluated as insignificant based on the following:

- The initiating event frequency for an external flood to reach grade level (i.e., 517 feet) is low (i.e., approximately 5E-5/yr based on a previous flood issue at Dresden (EA-13-079)).
- It is expected that normally there would be sufficient time available to shutdown and cooldown the plant such that the SRVs would not be needed to mitigate an external flood initiator.
- As long as off-site power and the main condenser are available, RCS cooldown can be accomplished using the bypass valves to the condenser without the need to use the SRVs.

Based on the above, the risk of this finding due to flooding is insignificant and will not be considered further.

SEISMIC

The SRAs used a seismically-induced LOOP event to represent the spectrum of seismic events that could lead to a change in core damage risk. For Dresden in the RASP manual, the frequency of a seismically-induced LOOP is 5.19E-5/yr as obtained from “Frequency of Seismically-Induced LOOP Events for SPAR Models,” Revision 3, dated August 2011. A seismically-induced LOOP can be modeled using any LOOP initiating event in the SPAR model without off-site power recovery. For the analysis, the SRAs chose to use a weather-related LOOP initiating event (IE-LOOPWR) without off-site power recovery.

For the Deficient Case, using the Dresden SPAR model with the following Change Sets: (1) Weather-Related LOOP (IE-LOOPWR) frequency set to 1.0, (2) no off-site power recovery, and (3) failure of 2C ERV (set to TRUE), a CCDP of 4.94E-5 was obtained.

For the Base Case with a Change Set with IE-LOOPWR frequency set to (1) 0, and (2) no off-site power recovery, a CCDP of 1.65E-5 was obtained.

Thus, the ΔCCDP was [4.94E-5 – 1.65E-5] = 3.3E-5.

The $\Delta CDF_{seismic}$ for a 210 day Exposure Time is:

$\Delta CDF_{seismic}$ = [5.19E-5/yr][3.3E-5][210 days/365 days] = 9.9E-10/yr

The seismic risk is thus 9.9E-10/yr. The risk of this finding due to seismic is insignificant and will not be considered further.

TOTAL EXTERNAL EVENTS RISK

The total external events $\Delta CDF_{external}$ is the sum of the fire, flood, and seismic risk or 1.0E-6/yr.

Potential Risk Contribution Due to Large Early Release Frequency (LERF)

The potential risk contribution due to Large Early Release Frequency (LERF) was considered using IMC 0609 Appendix H, “Containment Integrity Significance Determination Process." Dresden is a General Electric Co. boiling water reactor (BWR)-3 plant with a Mark I containment. Table 5.1 from Appendix H (Phase 1 screening) indicated that this issue required further evaluation since ATWS and High-RCS pressure sequences were important for BWRs with Mark I containments. Table 5.2 from Appendix H (Phase 2 analysis) listed a LERF Factor of 0.3 for ATWS sequences. For RCS high-pressure sequences (high-pressure defined as greater than 250 psi at the time of reactor vessel breach), Table 5.2 had a LERF factor of 0.6 if the drywell is flooded, and 1.0 if the drywell is not flooded.

A review of the dominant core damage sequences revealed the following:

- ATWS sequences represented a ΔCDF of 1.64E-7/yr. Based on a LERF Factor of 0.3, the ΔLERF due to ATWS core damage sequences is 4.74E-8/yr.
- High-RCS Pressure sequences (i.e., the failure of RCS depressurization) represented a ΔCDF of 1.36E-6/yr. Based on the dominant core damage sequences, the sequences that flood the drywell (i.e., LOCA sequences) have a

ΔCDF of 5.29E-7/yr. The non-LOCA sequences that may not result in the drywell being flooded have a ΔCDF of 8.29E-7/yr. Thus, the ΔLERF due to High-RCS Pressure core damage sequences is 1.15E-6/yr (i.e., [5.29E-7/yr][0.6] + [8.29E-7/yr][1.0] = 1.15E-6/yr).

The total ΔLERF is the sum of the ΔLERF due to the ATWS core damage sequences (i.e., 4.74E-8/yr), and the High-RCS Pressure sequences (i.e., 1.15E-6/yr). The total ΔLERF is 1.20E-6/yr (**Yellow**).

Evaluation of ΔLERF Contribution

The SRAs determined that the risk characterization of the issue for ΔLERF using the LERF factors specified in IMC 0609 Appendix H was conservative for this SDP evaluation for the following reasons:

- The dominant core damage sequences would not significantly contribute to LERF risk due to timing considerations. These sequences involve a failure of HPCI, and a failure to depressurize the RCS, resulting in the failure of any injection to the RCS (i.e., no low-pressure injection from the Core Spray or LPCI systems). These accident sequences (i.e., no RCS injection) are similar to the accident conditions that would be encountered during a Station Blackout (SBO) event without HPCI available. This is further discussed in paragraph 2 below.
- Per the State-of-the-Art Reactor Consequence Analyses (**reference Table 4 in NUREG-1935**), the timeline for the start of core damage to lower head failure (and subsequent release to the environment) during an SBO event without HPCI or rector core insolation cooling available is approximately **7 hours**. The SRAs reviewed licensee document EP-AA-1004, Addendum 2, Revision 01, titled "Evacuation Time Estimates for Dresden Generating Station Plume Exposure Pathway Emergency Planning Zone." Estimates show that Emergency Planning Zone (EPZ) evacuation times are in the **3 hour-45 minutes to 4 hour-30 minutes** timeframe, depending on the day of the week and weather conditions.
- Based on the **3 hour-45 minutes to 4 hour-30 minutes** timeframe for EPZ evacuation, and the dominant core damage sequences being later (i.e., approximately **7 hours per NUREG-1935**), the SRAs believe that in most cases EPZ evacuation would be completed before early release to the environment.
- Results of NRC-sponsored accident progression analyses in ERI/NRC 03-204, "The Probability Of High-Pressure Melt Ejection-Induced Direct Containment Heating Failure in Boiling Water Reactors with Mark I Design," indicates that without RCS injection during a SBO, there is a high-probability that the RCS would subsequently depressurize as a result of either temperature-induced creep rupture of the steam lines or a stuck open SRV (due to cycling at high temperature). The ERI/NRC 03-204 estimates a 0.9 probability of creep rupture of the steam lines during a SBO, and approximately a 0.5 probability of a stuck open SRV [if any SRV (i.e., ERVs or Target Rock SRV)] was available. If RCS depressurization occurs, the High-RCS pressure sequences and their contribution to ΔLERF are eliminated.
- Dresden has guidance in their Operational Contingency Action Guidelines that would also have the operators flood the drywell floor using an AC-independent pump and water source. It would be reasonable to expect that the required

actions to implement this strategy of flooding the drywell floor could be completed within a 7-hour time frame between the start of core damage to lower head failure (and subsequent release to the environment).

As a result of the above considerations, the use of a LERF multiplier based on a depressurized RCS and a flooded drywell floor would be appropriate. The analysts concluded that the risk due to ΔLERF is equivalent to the ΔCDF results for the event, i.e., the risk characterization of the issue should be based on the ΔCDF result of White.

Total Estimated Change in Risk

ΔCDF = 2.69E-6/yr (White)

The total change in ΔCDF is the sum of the internal and external events ΔCDF risk, or a ΔCDF of 2.69E-06/year (i.e., 1.69E-6/yr (internal) + 1.0E-6/yr (external) = 2.69E-6/yr) (White).

ΔLERF contribution is consistent with a risk of White based on ΔCDF.

A Significance and Enforcement Review Panel held on June 25, 2015, using IMC 0609, Appendix A, "Significance Determination Process For Findings At-Power," dated June 19, 2012, made a preliminary determination that the finding was of low to moderate safety significance (White) based on the quantitative analysis performed during the detailed risk evaluation.

The inspectors determined that this finding has a cross-cutting aspect of Resolution in the area of Problem Identification and Resolution, since it involves the failure to implement effective corrective actions to address issues in a timely manner commensurate with their safety significance. [P.3]

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the SSCs.

TS 3.4.3, SRVs, Limiting Condition for Operation requires, in part, that in Modes 1, 2, and 3, the relief function of five relief valves shall be OPERABLE. Required Action A, states that, if one relief valve is inoperable, then restore the valve to operable status within 14 days. Required Action B states, in part, that if the Required Action and associated Completion Time are not met, then (1) be in Mode 3 within 12 hours, and (2) be in Mode 4 within 36 hours.

TS 3.5.1, ECCS Operating, Limiting Condition for Operation requires, in part, that in Modes 1, 2, and 3, with pressure above 150 pounds per square inch gauge (psig), the ADS function of five relief valves shall be OPERABLE. Required Action H, states that, if one ADS valve is inoperable, then restore the valve to operable status within 14 days. Required Action I states, in part, that if the Required Action H and associated Completion Time are not met, then (1) be in Mode 3 within 12 hours, and (2) reduce reactor steam dome pressure to less than 150 psig within 36 hours.

From December 1, 2009, to February 7, 2015, the licensee apparently failed to establish measures to ensure that the application of the ADS ERV actuators, which are essential to perform the safety-related reactor vessel depressurization and overpressure protection functions, remained suitable for operation. This resulted in a failure of the 2C ERV which occurred during testing performed in mid-cycle outage D2F56, and an indeterminate period of inoperability and unavailability greater than allowed by TSs 3.4.3 and 3.5.1, during operating cycle D2C24 due to vibration induced wear of multiple actuator subcomponents. The 2C ERV inoperability during the operating cycle was identified after the failure of the valve during its first operational test following the Unit 2 shutdown for unrelated maintenance. Additionally, because the licensee was not aware of the valve's inoperability between 2013 and 2015 during operating cycle D2C24, the required actions in Actions 3.4.3 A and B, and 3.5.1 H and I were not followed.

Corrective actions implemented included replacing the Unit 2 ERV actuators with hardened actuators during forced outage D2F56 in February 2015, which are specifically designed to withstand the increased vibrations experienced during EPU operations. In addition, a procedure revision to MA-DR-EM-4-00200 has been implemented which provides specific guidance on how to align all components during reassembly, component replacement guidance based on wear measured, and specific guidance on how to characterize the wear any observed on the ERV actuator subcomponents. (**AV 05000237/2015002-04, Failure to Ensure Continued Operability of Unit 2 Electromatic Relief Valve 2–0203–3C (2C) Following Implementation of Extended Power Uprate Plant Conditions**).

4OA5 Other Activities

.1 Institute of Nuclear Power Operations Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final reports for the Institute of Nuclear Power Operations training accreditation conducted in the area of operations in January 2012, and maintenance, radiation protection, chemistry, and engineering in February 2014. The inspectors reviewed the reports to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings were identified.

.2 Operation of an Independent Spent Fuel Storage Facility Installation at Operating Plants (60855.1)

a. Inspection Scope

The inspectors reviewed the licensee's actions to address unresolved item (URI) 05000237/2010003-08; 05000249/2010003-08 "Potential Safety Significance of Free-Standing Stack Configuration during MPC [Multi-Purpose Canister] Transfer from HI-TRAC Transfer Cask into HI-STORM Storage Cask." The URI was identified by the inspectors to further evaluate regulatory requirements and acceptable analytical methods to demonstrate seismic adequacy during vertical transfer operations concurrent

with a postulated design basis seismic event. Vertical transfer operations, or stack-up, refers to the condition when a transfer cask (HI-TRAC) loaded with spent fuel is resting on a storage overpack (HI-STORM). The inspectors had several questions pertaining to the licensee's calculations used to demonstrate that the free-standing (unrestrained) stack-up configuration would not tip-over or excessively slide during a postulated design basis seismic event.

In response to the inspectors concerns, the licensee decided to abandon the plan to use a free-standing stack-up configuration within the Reactor Building and instead provided physical restraint of the system during the 2010 and subsequent loading campaigns. Specifically, Action Request (AR) 02421154, "HI-STORM / HI-TRAC URI Position," dated December 5, 2014, states, "the implementation of seismic restraints in 2010 for the DNPS [Dresden Nuclear Power Station] stack-up configuration ensured, and will continue to ensure, the safe handling of the HI-STORM/HI-TRAC stack-up configuration at DNPS." AR 02421154 further states, "EGC chose to not reanalyze the DNPS unrestrained configuration…nor does EGC, at the current time, intend to reanalyze the unrestrained stack-up configuration for DNPS."

Since the licensee has abandoned their plans to perform free-standing stack-up evolutions, the inspectors determined the unresolved item should be closed. Should the licensee choose to pursue an unrestrained stack-up in the future, the plans would be subject to NRC inspection. **(URI-05000237/2010003-08; 05000249/2010003-08 "Potential Safety Significance of Free-Standing Stack Configuration during MPC Transfer from HI-TRAC Transfer Cask into HI-STORM Storage Cask")**

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 1, 2015, the inspectors presented the inspection results to Mr. S. Marik, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for the areas of radiological environmental monitoring; and occupational exposure control effectiveness PI verification with Mr. Shane Marik, Site Vice President, on May 8, 2015.
- On May 28, 2015, the inspectors reviewed the examination overall pass/fail results with Mr. D. Siuda, Licensed Operator Requal Author and Instructor, via telephone.
- The results of the Independent Spent Fuel Storage Installation inspection were presented to Mr. Shane Marik and other members of the licensee's staff on June 26, 2015.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

4OA7 Licensee-Identified Violation

The following violation of very-low safety significance (Green) was identified by the licensee, and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy, for being disposition as an NCV.

- The TS 5.5.1 required that the Offsite Dose Calculation Manual (ODCM), and its Radiological Environmental Monitoring Program (REMP) be established, implemented, and maintained. ODCM Radiological Environmental Control No. 12.6.1 defined the surveillance requirements for the REMP. Step E of this section provided requirements for Milk Station D-25 (Control) be sampled within 10 km to 30 km semimonthly as indicated in Table 12.6-1.4.a. Contrary to the requirements, the licensee did not sample the control Milk Station D-25. The missed samples were not identified by the licensee until March 2015. This issue was entered into the licensee's CAP as AR-02469852.

The finding is more than minor because it impacted the Public Radiation Safety Cornerstone, and adversely affected the cornerstone objective of ensuring adequate protection of public health and safety from exposure to radiation during routine operations of civilian nuclear power reactor. The finding was also assessed using IMC 0609, Appendix D, and Public Radiation Safety SDP, and was determined to be of very-low safety significance (Green) because it involved the Environmental Monitoring Program.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

S. Marik, Site Vice President
J. Washko, Station Plant Manager
L. Antos, Security Manager
J. Biegelson, Engineering
M. Overstreet, Radiation Protection Manager
D. Doggett, Emergency Preparedness Coordinator
B. Frazen, Regulatory Affairs Manager
F. Gogliotti, Engineering Director
G. Graff, Nuclear Oversight Manager
M. Hosain, Site EQ Engineer
B. Kapellas, Maintenance Director
D. Kim, Design Engineer
M. Knott, Instrument Maintenance Manager
G. Morrow, Operations Director
P. O'Brien, Regulatory Assurance – CAP Coordinator
W. Painter, ALARA Manager
M. Pavey, Health Physicist
A. Pullam, Training Director
J. Quinn, Work Control Director
D. Siuda, Licensed Operator Requal Author and Instructor
A. Triventi, CHP, REMP/RETS/ODCM Chemistry
D. Walker, Regulatory Assurance – NRC Coordinator

U.S Nuclear Regulatory Commission

A. Boland, Director, Division of Reactor Projects
J. Cameron, Chief, Division of Reactor Projects, Branch 4
N. Valos, Senior Reactor Analyst

IEMA

M. Porfirio, Resident Inspector, Illinois Emergency Management Agency

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000237/2015002-01; 05000249/2015002-01	FIN	Failure to Meet Technical Specification Surveillance Requirements Due to Foreign Material Left in the Unit 2 EDG Starting Circuit (1R13)
05000237/2015002-02	NCV	Inadvertent Manipulation of a Test Switch at ESF Bus 23-1 During Surveillance Testing Results in the Inoperability of the 2/3 EDG to Unit 2 (1R22)
05000237/2015002-03	FIN	Reactor Scram Due to Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback (4OA3.1)
05000237/2015002-04	AV	Failure to Ensure Continued Operability of Unit 2 ERV 2-0203–3C (2C) Following Implementation of Extended Power Uprate Plant Conditions (4OA3.2)

Closed

05000237/2015002-01; 05000249/2015002-01	FIN	Failure to Meet Technical Specification Surveillance Requirements Due to Foreign Material Left in the Unit 2 EDG Starting Circuit (1R13)
05000237/2015002-02	NCV	Inadvertent Manipulation of a Test Switch at ESF Bus 23-1 During Surveillance Testing Results in the Inoperability of the 2/3 EDG to Unit 2 (1R22)
05000237/2015002-03	FIN	Reactor Scram Due to Feedwater Level Control System Failure with a Reactor Recirculation Pump Runback (4OA3.1)
05000237/2015001-00	LER	Unit 2 Scram Due to Feedwater Level Control Issues (4OA3.1)
05000237/2015001-01	LER	Unit 2 Scram Due to Feedwater Level Control Issues (4OA3.1)
05000237/2015002-00	LER	2C ERV Failed to Actuate during Extent of Condition Testing (4OA3.2)
05000237/2015002-01	LER	2C ERV Failed to Actuate during Extent of Condition Testing (4OA3.2)
05000237/2010003-08; 05000249/2010003-08	URI	Potential Safety Significance of Free-Standing Stack Configuration during MPC Transfer from HI-TRAC Transfer Cask into HI-STORM Storage Cask (4OA5.2)

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather Protection (71111.01)

- IR 2502354, "TR-86 Relay House East Door Handle Missing"
- IR 2502339, "345 kV 125 Vdc Sys. 2 Pilot Cell 36 Specific Gravity HOS"
- IR 2496576, "Unexpected Alarm During Testing"
- IR 2502821, "NRC Switchyard Walkdown Results"
- WO 1743751-01, "Performing U2 Main Generator Min/Max VAR Test"
- DOP 6400-08, "345 kV Voltage Control," Revision 34
- DOA 6500-12, "Low Switchyard Voltage," Revision 25
- Design Analysis Major Revision Cover Sheet for DRE 04-0019, "Auxiliary Power Analysis for Dresden Unit 3," Revision 006
- WC-AA-101, "On-Line Work Control Process," Revision 24
- WC-AA-107, "Seasonal Readiness," Revision 15
- OP-AA-108-107-1001, "Station Response to Grid Capacity Conditions," Revision 6
- OP-AA-108-107-1002, "Interface Procedure Between ComEd/PECO and Exelon Generation (Nuclear/Power) For Transmission Operations," Revision 8
- Work Planning Instruction for EC 382480, "Unit 3 Automatic Voltage Regulator Replacement," Revision 003
- LER 237/2005-003, "Units 2 and 3 Off-Site Power Sources Declared Inoperable Due to Low-Voltage"
- IR 2518113, "Suspension of Safeguards Due to Severe Weather"
- IR 2518096, "Water/Oil on U3 TB 517' Floor"
- IR 2518083, "DOA Entry for L1263 Trip"
- IR 2518080, "Water Intrusion by Bus 23"
- IR 2518045, "DOA 0010-02 Entry Due to Tornado Warning"
- IR 2514558, "2/3 Heating Fuel Tank Berm High Water Level"
- IR 2514926, "U2 and U3 Generator Outputs Spikes"
- IR 2514978, "Unexpected Alarm 923-2 B-7, DFR/DME & 345 kV RLY Hse Sump Hi"
- IR 2514989, "345kV SWYD Relay House B Sump Not Working"
- IR 2515095, "Flash Flood Causes 2/3 Oil Sep and WWT to Overflow"
- IR 2515107, "Water Dripping on Motor for 3C Circ Pump Disch Valve"
- IR 2515109, "U2 125Vdc Battery Ground"

1R04 Equipment Alignment (71111.04Q and S)

- IR 2491673, "Procedure REV Needed to COP 1100-E1"
- DOP 1100-E1, "Unit 2 Standby Liquid Control Electrical Checklist," Revision 07
- DOP 1100-M1, "Unit 2 Standby Liquid Control System Checklist," Revision 14
- DOP 2300-M1/E1, "Unit 2 HPCI System Checklist," Revision 39
- WO 1838452-01, "Repair 3-4706-A (Compressor) 3A Instrument Air"
- WO 1838452-02, "FNI to Replace Oil Temperature Sensor 3-4741-215A for 3A IAC Due to Trip on High Oil Temperature"
- IR 2514455, "Evaluate Air Compressor Oil Coolers for Sediment"

- IR 2513562, “3A Instrument Air Compressor Trip”
- IR 2406595, “3A IAC Trip/DOA Entry”
- IR 1668354, “Foreign Material in System Due to Chk Vlv Disc Failure”
- IR 1666171, “DOA 4700-01 Instrument Air Failure Entry”
- IR 1665924, “DOA 4700-01 Instrument Air Failure Entry”
- IR 1652167, “2A IAC Tripped – Found Frayed Wires on 2-4741-244 in Field”
- IR 1646851, “2B IAC Not Working Properly”
- IR 1537323, “Compressor Tripped on Low Oil Pressure”
- IR 1532930, “3C IAC Trip on Low Oil Pressure During Start”
- Maintenance Rule System Basis Document for Instrument Air
- DOP 4700-01, “Instrument Air System Startup,” Revision 62
- DOP 4700-M1, “3A Instrument Air Compressor (3-4706) Checklist,” Revision 08
- Drawing: M-367, Diagram of 3A Instrument Air Piping
- Drawing: M-367, Diagram of Instrument Air Piping for 3A & 3B Compressors
- IR 2510912, “NRC Requested Information”
- IR 2510441, “Appendix R DSSP Jumper Use Review and Conclusion”
- IR 2509063, “No ELUS in Place for Appendix R Manual Actions”
- IR 2478665, “DSSP Action Not Permissible for Appendix R”
- IR 1669842, “DOP 2000-97 Limitations Lack Appendix R Discussion”
- IR 1669137, “Elevated Tritium Readings on STP Effluent”
- Calculation DRE98-0030, “Determination of Setpoint of CST Low-Low Level Switches to Prevent Potential Air Entrainment from Vortexing During HPCI Operation,” Revision 000C
- Calculation DRE98-0030, “Determination of Setpoint of CST Low-Low Level Switches to Prevent Potential Air Entrainment from Vortexing During HPCI Operation Essential Calc,” Revision 0B
- Calculation DRE98-0030, “Determination of Setpoint of CST Low-Low Level Switches to Prevent Potential Air Entrainment from Vortexing During HPCI Operation,” Revision 0A
- Calculation DRE98-0030, “Determination of Setpoint of CST Low-Low Level Switches to Prevent Potential Air Entrainment from Vortexing During HPCI Operation,” Revision 0
- Calculation SEC-DR-99-008-01, “Evaluation of Safety Related 250Vdc Battery Sizing Calculation for Physically Raising the Low Condensate Storage Tank Level Switches,” dated April 7, 1999
- DAN 902(3)-6 A-6, Setpoint for U2/3B Cond Storage Tank Lvl Hi-Lo, Revision 19
- DOP 2300-03, “High-Pressure Coolant Injection System Manual Startup and Operation,” Revision 40
- DSSP 0100-C, “Hot Shutdown Procedure – Path C,” Revision 26
- DSSP 0100-D, “Hot Shutdown Procedure – Path D,” Revision 25

1R05 Fire Protection (71111.05A & Q)

- IR 251625, “Fire Protection – Fire Drill”
- Fire Drill Scenario 04A, “U3 MCC 39-1 Cubical Fire,” June, 2014
- OP-AA-201-003, “Fire Drill Record,” Revision 14
- Dresden Pre-Fire Plan for Fire Zone 1.1.1.2, Unit 3 Ground Floor, Elevation 517’
- IR 2479797, “AEER A/C Compressor Still Tripping”
- Dresden Generating Station Pre-Fire Plan for Fire Zone 6.2
- OP-AA-201-008, “Pre-Fire Plan Manual,” Revision 3
- OP-AA-201-009, “Control of Transient Combustible Material,” Revision 16
- CC-AA-211, “Fire Protection Program,” Revision 6
- Dresden Generating Station Pre-Fire Plan for Fire Zone 18.7.1
- Dresden Generating Station Pre-Fire Plan for Fire Zone 18.7.2

- IR 2516073, “NRC ID: CO2 Hose Reel #33 Light Out”
- IR 2462987, “CO2 Hose Reel #33 Light Out”
- Dresden Generating Station Pre-Fire Plan for Fire Zone 8.2.6E
- OP-DR-201-012-1001, “Dresden On-Line Fire Risk Management,” Revision 03
- IR 2517896, “Fire Protection – Pre-Fire Plans”
- Dresden Generating Station Pre-Fire Plan for U2 SBO SWG EER “3rd Floor East”
- Dresden Generating Station Pre-Fire Plan for SBO DG 2

1R06 Flooding (71111.06)

- IR 2502138, “Need to Dewater Security MH-1”
- IR 2497672, “Need to Dewater Switchyard MH-2”
- IR 2496680, “Multiple Leaks in the 2/3 Cribhouse Through Penetrations”
- IR 2496464, “Need to Dewater Security Manhole #1”
- IR 2488287, “SEC[security] MH-1 Requires Dewatering”
- IR 2488285, “SWYD[switchyard] MH-1 Requires Dewatering”
- WO 1422805, “D2/3 3M Com Insp / De-water Outside Manhole (SBO–MH #2)”
- PMRQ # 186236-02, “3M Com INSP / De-Water Outside Manhole (SBO-MH#3)”
- PMRQ # 186236-04, “3M Com INSP / De-Water Outside Manhole (SBO-MH#2)”
- PMRQ # 186236-07, “3M Com INSP / De-Water Outside Manhole (SBO-MH#1)”
- ER-AA-300-150, “Cable Condition Monitoring Program,” Revision 0
- Drwg: Manhole Location Drawing Dresden Station

1R11 Licensed Operator Requalification Program (71111.11)

- IR 2502004, “Crew 3 U3 RWCU Trip Response 4.0 Critique”
- IR 2500184, “DOA 6500-10 4kV Circuit Bkr Trip Entry Due to U3 RWCU Trip”
- IR 2500112, “U3 RWCU System Trip”
- Prompt Investigation for 05/13/2015 Unit 3 RWCU isolation due to failure in division 1 HELB isolation circuitry, IR 2500112.
- DGA-07, “Unexpected Reactivity Change,” Revision 24
- DOP 1200-03, “RWCU System Operation With The Reactor at Pressure,” Revision 66
- Drwg: 12E-3524A, Schematic Diagram Reactor Water Cleanup System, Train A

1R12 Maintenance Effectiveness (71111.12)

- IR 2478054, “U3 HPCI SSPI Forecasted Unavail. Was Exceeded March 2015”
- IR 2463014, “D2 HPCI Maint Rule Functions 23-1 & 23-2 IN (A)(2) At Risk”
- IR 1536323, “Unexpected Alarm for 903-3 H-9”
- IR 1591416, “Failure of HPCI Turb Stop Valve to Indicate/Open During Test”
- IR 1369302, “Steam Leak Found on HPCI ASME Code Class Piping”
- IR 1382386, “U2 HPCI Unavailability Exceeded (A)(1) Limit”
- ER-AA-310-1001, “Maintenance Rule – Scoping,” Revision 4
- ER-AA-310-1002, “Maintenance Rule Functions – Safety Significance Classification,” Revision 3
- ER-AA-310-1003, “Maintenance Rule – Performance Criteria Selection,” Revision 4
- ER-AA-310-1004, “Maintenance Rule – Performance Monitoring,” Revision 13
- ER-AA-310-1005, “Maintenance Rule – Dispositioning Between (a)(1) and (a)(2),” Revision 7
- ER-AA-310-1009, “Maintenance Rule Program Performance Indicators,” Revision 2
- ER-AA-310-1008, “Maintenance Rule Process Map,” Revision 0
- Maintenance Rule Expert Panel meeting notes from 12/04/2013
- Maintenance Rule Expert Panel meeting notes from 05/07/2014

- Maintenance Rule Expert Panel meeting notes from 09/25/2014
- Maintenance Rule Expert Panel meeting notes from 01/29/2015
- WO 1835285-01, “Inspect/Replace EDG Air Start System Components”
- IR 2512377, “NRC Inspector Questions – EDG Maintenance Rule”
- IR 2507670, “Review Potential Single Point Vulnerability for EDG Failures”
- IR 2507485, “U3 EDG Failed to Start”
- IR 2507539, “No Chem Add to 3 EDG Due to Known Biocide Leak”
- IR 2506187, “2/3 Diesel Generator Cooling Water Pump Failure Analysis”
- IR 2498851, “U2/3 66-1 Needs (A)(1) Determination”
- IR 2498808, “U2 66-1 Needs (A)(1) Determination”
- IR 2498788, “U2 EDG Enters Maint Rule A(2) at Risk”
- IR 2495747, “IR Reviews Exceed 30 Days”
- IR 2494098, “Visual Inspection of Wire Lug Crimps”
- IR 2488474, “U2 EDG Fail to Start”
- IR 2486980, “SPC 2454408 02-Silver U2/3 EDG Lubricating Oil”
- IR 2481417, “2/3-6699-105 Air Start Relay Valve Air Leak”
- IR 2481287, “U2/3 EDG Enters Maint Rule A(2) at Risk”
- IR 2479188, “2/3-6600-IR2 Failed to Pick Up During Testing”
- IR 2478701, “Trend IR: For U3 EDG Oil Level”
- IR 2478304, “Valve Failed Inspection”
- IR 2477804, “2/3 EDG Air Start SOV O-ring is Degraded”
- IR 2457788, “Request One Time Replacement of 3 EDG ESR Relay”
- IR 2457787, “Request One Time Replacement of 2 EDG ESR Relay”
- IR 2457786, “Request One Time Replacement of 2/3 EDG ESR Relay”
- IR 2457785, “Request One Time Replacement of 3 EDG VSR Relay”
- IR 2457784, “Request One Time Replacement of 2/3 EDG VSR Relay”
- IR 2446894, “U3 EDG LCO Critique”
- IR 2445789, “U3 EDG Pressure Regulator Gauge Leaking”
- IR 2444898, “Tracking-Silver in U2/3 EDG Lo-Wrist Pin Degradation”
- IR 2443876, “Unit 3 Diesel Fuel Transfer Pump Higher Vibes”
- IR 2440534, “U2 EDG Starting Air Drain Valve Packing Leak Getting Worse”
- IR 2400902, “Perform Engine Analysis on 2/3 EDG”
- IR 2398342, “2/3 EDG Oil Analysis Trends”
- IR 2389220, “Recommended Additional Troubleshooting Actions for U2 EDG”
- IR 2388132, “U2 EDG Semi-Annual Fast Start Failure”
- IR 1698832, “U2 Fast Start Data Inconclusive”
- IR 1475119, “Re-Occurring Unexpected U2 EDG Alarm”
- Apparent Cause Investigation Report (Equipment) (EACE) for IR 2490533, “FA Report for Failed Lockout Relay – U2 EDG Lockout Relay FA,” dated May 22, 2015
- EACE for IR 2488474, “U2 EDG Fail to Start,” dated May 19, 2015
- EACE for IR 2486980, “SPC 02454408 02-Silver U2/3 EDG Lubricating Oil,” dated May 21, 2015
- EACE for IR 1352666, “Unit 2/3 Emergency Diesel Generator,” dated February 7, 2014
- Maintenance Rule Panel package for June 23, 2015
- MR Function Evaluation for Emergency Diesel Gen (66-1 and 66-7), for April 2015
- MR Periodic Assessment #10 (10CFR50.65 (a)(3) Assessment) for the period of 10/1/2012 – 9/30/2014, dated December 16, 2014
- MR Performance Criteria for Z66-1, dated July 31, 2014
- Maintenance Rule System Basis Document for Dresden Emergency Diesel Generators
- Maintenance Rule System Basis Document for Dresden Unit 2 Local Power Range Monitoring (LPRM)

- Maintenance Rule System Basis Document for Quad Cities Unit 1 LPRM
- Determination Issue Report Number 1619765, “IR 1604658, 2B Reactor Recirc Pump Trip,” dated February 12, 2014
- Determination Issue Report Number 1352666-05, “Emergency Diesel Generators & Aux.,” dated June 15, 2012
- Determination Issue Report Number 1352666, “Unit 2/3 Emergency Diesel Generators & Aux.,” dated May 4, 2012
- Determination Issue Report Number 1198767, “Unit 2/3 Emergency Diesel Generator,” dated May 6, 2011
- SSC Maintenance Rule for Z66-7, “Isolation Condenser Makeup Water Supply From Unit 2 EDG Cooling Water System,” approved September 12, 2006
- ER-AA-440, “Emergency Diesel Generator (EDG) Reliability Program,” Revision 1
- ER-AA-310-1004, “Maintenance Rule – Performance Monitoring,” Revision 13

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

- IR 2490022, “Found FME in U2 D/G Main Bearing Low Oil Pressure (MB1) PS”
- IR 2489449, “Lack of Awareness of Troubleshooting Plan Website”
- IR 2489408, “Appendix X Requires Revision”
- IR 2488474, “U2 EDG Fail to Start”
- IR 1377813, “EDG Sensing Lines Need to be Replaced”
- IR 2490378, “Need Work Packages for the Unit 3 EDG PS Replacement”
- IR 2490385, “Need Work Order to Replace the 2/3 EDG Oil PS”
- IR 2494135, “Unit 2 EDG Failed to Start – OCC Critique”
- WO 1635025, “D2 24 M TS D/G Test/Endur & Margin/Full Load REJ/ECCS”
- WO 1410972, “D2 4Y PM D/G Engine Press Instr Calibration”
- DIS 6600-03, “Unit 2 Diesel Generator Pressure Switches and Pressure Indicators Calibration,” Revision 14
- DIS 6600-03, “Unit 2 Diesel Generator Pressure Switches and Pressure Indicator Calibration,” Revision 15
- DES 6600-08, “Diesel Generator Electrical Maintenance Surveillance Inspection,” Revision 29
- Drawing: M-478, Diagram of Diesel Generator Lube Oil Piping
- Drawing: 12E-2350A, Schematic Diagram, Engine Control & Gen. Excitation Standby Diesel Generator-2
- Drawing: 12E-2644, Wiring Diagram Standby Diesel Generator 2 Engine Equipment Control Panel
- Apparent Cause Investigation Report, “U2 EDG Fail to Start,” dated May 19, 2015
- ER-AA-2006, “Lost Parts Evaluations,” Revision 9
- Dresden Lost Parts List: Unit 2/3 EDG AMOT valve o-ring fragments, dated 03/26/2012
- Dresden Lost Parts List: Historical Data, rubber lining from a short length of flexible hose, dated 06/21/2011
- Dresden Lost Parts List: Found FME in U2 D/G Main Bearing Low Oil Press (MB1) PS, dated 04/23/2015
- Protected Equipment List for Unit 2 2A SBLC
- DES 8300-24, “Unit 3 125 Volt Main Station Battery Service Test,” Revision 20
- Drwg: 263LN002-001, 125 Vdc System
- IR 2502695, “Mispositioned Test Switch During Performance of DIS 1500-05”
- IR 2503197, “Protected Pathway Not Posted When Required”
- WO 1614824-01, “DIS 1500-05 Div I & II LPCI ECCS INIT Circuitry LSFT”
- OP-DR-108-117-1001, “Protected Equipment and Pathway Policy,” Revision 06
- OP-AA-108-117, “Protected Equipment Program,” Revision 4

- Appendix X, “Technical Specification Action Statement Initiated Surveillance,” Revision 34

1R15 Operability Determinations and Functional Assessments (71111.15)

- IR 02449137, “2C Emergency Relief Valve Failed to Operate, Historical Operability Review”
- IR 2451103, “Potential Vibration Induced Degradation”
- IR 2467676, “Historical Operability of 2-0203-3C ERV Actuator”
- IR 2493733, “U3 Forced Outage WO Recommendation: ERV Actuator Inspection”
- Prompt Investigation for IR 2445040 and IR 2450437
- AR 00189474-01, “Evaluate valve testing and maintenance on ERV during D3M10 and determine if a condition existed that could have prevented the valve operation with the Unit at power prior to D3M10. If such a condition was existing, document in a CR and notify Shift Manager to evaluate Reportability”
- Exelon Power Labs report for DRE-74103, “Failure Analysis of the 2C ERV Solenoid Actuator”
- LER 237/2015-002-00, “2C ERV Failed to Actuate During Extent of Condition Testing”
- LER 237/2015-002-01, “2C ERV Failed to Actuate During Extent of Condition Testing”
- EC 401652, Revision 000, “Evaluation of Elevated Vibration Readings on U3 HPCI Aux Oil Pump Motor”
- WO 1818352-06, “TS/Repair (HPCI Aux Oil Pump Motor 3-2303-AOP)”
- IR 2474065, “Unit 3 HPCI Aux Oil Pump Motor Shorted”
- IR 2476080, “U3 HPCI Aux Oil Pump Elevated Vibration”
- IR 2478177, “Evaluation Needed to Determine Proper Response of HPCI AOP”
- ER-AA-321-1007, “Inservice Testing (IST) Program Corporation Technical Positions,” Revision 1
- ASME OM Code – 2004, Subsection ISTB, “Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants”
- IR 2487211, “FI Found Out of Tolerance Would Not Calibrate”
- DIP 3900-01, “Diesel Generator Cooling Water Flow Indicator AND Pump Suction AND Discharge Gauge Preparation for In-Service Testing,” Revision 07
- Drawing: M-355, Diagram of Service Water Piping
- Drawing: M-517, Diesel Generator Engine Cooling Water System
- IR 2497065, “Pin Hole Leak Identified on Unit 3 CCSW DIV I Piping”
- WO 1829523-01, “Repair pin hole leak identified on line #3-1512-24”-O by installing a half coupling per EC 402077”
- ASME Section XI Repair/Replacement Plan for WO 1829523-01
- DCP Number 402077, “Perform Code Repair on the Through-Wall Leak of the CCSW DIV I Header Piping 3-1512-24”-O in the Crib House (WO 1829523),” Revision 000
- Engineering Change (EC) 361581, “Calculate code and operability minimum wall thickness for CCSW Lines 2(3)-1505-24”-O and 2(3)-1512-24”-O,” Revision 0
- Work Planning Instruction for EC 402077, “Perform Code Repair of Through-Wall Leak on the CCSW Div I Header Piping 3-1512-24”-O in 2/3 Crib House,” Revision 000
- Ultrasonic Thickness Calibration Report #15-101, for work order 1742941-01.
- ASME Weld Data Record for Work Package 1829523-01
- IR 2516897, OWAB Identifies Two New Operator Challenges”
- IR 2507698, “U2 Hydrogen Addition System Operation in Manual”
- IR 2493160, “Possible Operator Challenge in Upcoming Rev of DOP 5600-06”
- IR 2447425, “Recommend 3-0590-102B Relay Be Considered for Challenge List”
- IR 2447419, “Recommend CRD D-11 Be Considered for Operator Work Around”
- IR 2447414, “Recommend Failed Fuel Be Considered for Operator Work Around”
- IR 241006, “U3 ESS Bus Normal Supply Inverter Operation”
- IR 2397461, “U2 Moisture Separator Level Turbine Trip Setpoint”

- IR 1532475, “Operator Work-Around Challenge DOP 2000-157”
- IR 1501211, “Engineering Review on OWA for CCSW Pumps”
- IR 1451198, “U3 H2 Supply to Generator Casing PRV”
- IR 1430563, “Proceduralized Operator Work Around”
- WO 1813239, “D2/3 Qtr AD Operations Aggregate Equipment Status Review”
- OP-AA-102-103-1001, “Operator Burden and Plant Significant Decisions Impact Assessment Program (CM-1),” Revision 6
- OP-AA-102-103, “Operator Work-Around Program,” Revision 4
- OWAB [Operator Work Around Board] Second Quarter 2015 Meeting minutes

1R19 Post-Maintenance Testing (71111.19)

- WO 1825570, “U2 EDG Fail to Start”
- WO 1635025, “D2 24M TS D/G Test/Endur & Margin/Full Load REJ/ECCS”
- DOS 6600-01, “Diesel Generator Surveillance Test,” Revision 128
- DOS 6600-12, “Diesel Generator Tests Endurance and Margin/Full Load Rejection/ECCS/Hot Restart,” Revision 60
- DOS 6620-07, “SBO 2(3) Diesel Generator Surveillance Tests,” Revision 40
- WO 1640588, “D2 2YR PM SBO DG Mechanical Maintenance Inspection”
- WO 1739653-04, “PMT U2 SBO Governor”
- WO 1783699-01, “Troubleshoot/adjust U2 SBO Cool Down (idle) Speed”
- WO 1803408-01, “D2 QTR COM SBO Diesel Generator Surv Test”
- IR 2402044, “U2 SBO Cooldown Speed High”
- IR 2496873, “Improper Crimps Found in U2 SBO ECP-B”
- IR 2497422, “U2 SBO 125 Vdc Ground”
- IR 2497471, “EOC Inspection of 3A SBO Turbo and Inlet Piping”
- IR 2497472, “EOC Inspection of 3B SBO Turbo and Inlet Piping”
- IR 2497599, “U2 SBO Diesel PLC Fault Alarm, 2202-105 F-3”
- IR 2498015, “WO 1783699-01 Unable to Complete as Scheduled”
- IR 2498031, “U2 SBO Primary Damper Failed to Fully Close”
- IR 2498079, “Unexpected Alarm: 125Vdc SWBD 6A Ground Fault”
- IR 2498613, “SBO Non-Lead Bank Starting Air Receiver Pressure”
- WO 575412, “OP PMT Solenoid Valve for U3 Isolation Condenser Vent Inboard”
- WO 575413, “OP PMT Solenoid Valve for U3 Isolation Condenser Vent Outboard”
- DOS 1600-05, “Unit 3 Quarterly Valve Timing (W-9),” Revision 48
- Drwg: 12E-3506, Schematic Diagram for Primary Containment Isol. Condenser Control, Logic SH-6
- WO 1841283, “Cable Came Loose on Trash Rake During Operation”
- IR 2518657, “Cable Came Loose on Trash Rake During Operation”
- IR 2518599, “Entry Into DOA 4400-06”
- DOP 4400-14, “Trash Rake Operation,” Revision 05

1R22 Surveillance Testing (71111.22)

- ASME OM Code – 2004, Subsection ISTB, “Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants”
- DOS 1100-04, “Standby Liquid Control System Quarterly/Comprehensive Pump Test for the Inservice Testing (IST) Program,” Revision 49
- WO 1659474, “D2 2Y TS 2A SBLC Pmp Comprehensive Test for In-Serv Testing”
- Inservice Testing (IST) Program Plan, Fifth Ten-Year Interval, November 1, 2013 – October 31, 2023, Revision 0, dated November 1, 2013

- DOS 1500-10, “LPCI System Pump Operability and Quarterly Test with Torus Available and Inservice Testing (IST) Program,” Revision 69
- DOS 2000-180, “Drywell Sump Operation With Unit On-Line,” Revision 04
- IR 2486672, “Cannot Establish Div. 1 LPCI Keep Fill”
- IR 2495028, “U2 Drywell Equip Sump LVL Hi-Hi Alarm Rec’d”
- IR 2501048, “Appendix A Needs to be Revised”
- IR 2505583, “NRC Resident Inspector Questions on U2 DW Leakage”
- WO 495832, “U2 Drywell Equip Sump Simple Troubleshooting”
- ACMP issued 05/28/2015, “Dresden Unit 2 Drywell Identified Leakage (Drywell Drain Sump DWEDS)”
- Drawing: M-360, Diagram of LP Coolant Injection System
- Drawing: M-358, Diagram of Core Spray Piping
- WO 1815850, “Evaluation of Recent U3 1A MSIV Closure Testing”
- DOS 0500-27, “Unit 3 Main Steam Line Isolation Valve Closure Scram Circuit Functional Test,” Revision 03
- Drawings:
- 12E-3463, Reactor Protection System Channel “A” Trip Aux. Relays
- 12E-3464, Reactor Protection System Channel “B” Trip Aux. Relays
- 12E-3469, Reactor Protection System Alarms & Computer Inputs
- 12E-3502, Primary Containment Isolation Sys. Switch Development, Reset CKT. TIP. ISOL. RECIRC. Loop Intlk
- 12E-3504, Pri. Containment Isolation Sys. Main Steam Isolating Circuit Inboard
- 12E-3819C, Primary Containment Isolation Main Steam Valves, Junction Box 3RB-33, 34, 35, 36 & 3TB-63, 64, 65, 66
- DOS 1600-32, “Secondary Containment Leak Rate Test,” Rev. 16
- WO 1588967, “D2/3 24M TS Secondary Containment Leak Rate Test”
- IR 2493046, “MCR RB DP Indicator Not Accurate”
- IR 2493599, “Revision Needed to DOS 1600-32”
- DAN 923-5 C-1, “Annunciator Response Procedure,” Revision 17
- DAP 07-44, “Control of Temporary Openings in Secondary Containment During Performance of Work Packages, Surveillances, or Other Procedures,” Revision 14
- DIS 1500-05, “Unit 2, 24 month LPCI System Logic Functional Surveillance (LSFT)”
- DIS 1500-05, “Division I & II, Low Pressure Coolant Injection ECCS Initiation Circuitry Logic System Functional Test,” Revision 32
- WO 1614824, “D2 24M TS Div 1 & 2 LPCI Inj ECCS Initiation Circuitry LSFT”
- IR 2502695, “Mispositioned Test Switch During Performance of DIS 1500-05”
- IR 2502875, “Fatigue Assessment for EO Post Event”
- IR 2502882, “Fatigue Assessment for EO Post Event”
- IR 2503568, “Computer Point T001 Did Not Display as Required”
- IR 2503572, “As Found TDR 2-1530-205 (CW) Not Recorded, Not Tech Spec”
- Apparent Cause Investigation Report, IR 2502695, “Mispositioned Test Switch During Performance of DIS 1500-05,” dated June 18, 2015.
- Drawings:
- 12E-2757B, Wiring Diagram Auxiliary Electric Equipment Room, Panel 902-32
- 12E-2437, Schematic Diagram LPCI/Containment Cooling System 1
- 12E-2655G, Internal Schematic and Device Location Diagram 4160V Switchgear Bus 23-1 Cubicle 13
- 12E-2344, Schematic Control Diagram 4160V Bus 23-1 Feed Breakers
- 12E-2345, Schematic Diagram 4160V Bus 23-1 Undervoltage Relays

1EP6 Drill Evaluation (71114.06)

- EP-MW-114-100-F-01, “Nuclear Accident Reporting System (NARS) Form,” Revision H

2RS7 Radiological Environmental Monitoring Program (71124.07)

- IR 02469852, IR was Initiated for “REMP Milk Sampling Anomaly,” dated March 17, 2015
- IR 02469852, IR Initiated “Because Teledyne Brown Engineering did not Analyzed the Sample when the Sample was Received,” dated May 1, 2015
- IR 01683942, IR Initiated for “REMP Sampling Issues in 2014,” dated July 21, 2014
- IR 02411283, “REMP Sampling Issues,” dated November 13, 2014
- Annual Report on the Meteorological Monitoring Program at Dresden NPS 2013; Murray and Trettel, Inc.
- Dresden-UFSAR, 2.3-1 “Meteorology,” Revision 7
- EIML-SPM-1, “REMP Sampling Procedures Manual for Dresden,” Environmental Incorporated Midwest Laboratories, Revision 15
- Environmental, Inc., Midwest Laboratory, “Quarterly Collection Schedule Period 4th Quarter 2014”
- Teledyne Brown Engineering Environmental Services, “Annual Quality Assurance Report 2013,” dated January – December 2013
- Dresden Nuclear Power Station 2014 Annual Radioactive Effluent Release Report
- Dresden Nuclear Power Station Units 1, 2 and 3; Annual Radiological Environmental Operating Report 2014
- Dresden OSLD Environmental Monitoring Summary for West Dry Cask Storage Area – 2014
- Dresden OSLD Environmental Monitoring Summary for East Dry Cask Storage Area – 2014
- EA Engineering, Science, and Technology, Inc., PBC; Fish Indicator Samplings in the vicinity of Plant Discharge Area of Dresden Nuclear Power Station
- CY-AA-170-000, “Radioactive Effluent and Environmental Monitoring Programs,” Revision 5
- CY-AA-170-100, “Radiological Environmental Monitoring Program,” Revision 2
- CY-AA-170-1000, “Radiological Environmental Monitoring Program and Meteorological Program Implementation,” Revision 8
- CY-AA-170-300, “Offsite Dose Calculation Manual Administration,” Revision 2

4OA1 Performance Indicator Verification (71151)

- LS-AA-2140, “Monthly Data Elements for NRC Occupational Exposure Control Effectiveness: Attachment 1,” Revision 5
- Reviewed Data Collection from January 2014 through March 2015, and also Reviewed Related Corrective Action Program Data between 2014 through 2015

4OA2 Identification and Resolution of Problems (71152)

- NRC Information Notice 2008-13, “Main Feedwater System Issues and Related 2007 Reactor Trip Data”
- Action Plan Development for IR 2454749, dated April 15, 2015
- PMID # 00174279-01, Root Cause for components 2-0640-32 and 33
- IR 1699697, “Unexpected U2 FWLC Alarm (U2-Di040 Backup MFP Bad Status)”
- IR 2394030, “U2 FWLC Alarm 902-6 H-3 Due to D.C.S. Failure”
- IR 2436166, “FW Control System Trouble Alarm”
- IR 2437067, “Revise U2 PMID 163901 and U3 PMID 163902 Work Orders”
- IR 2449224, “Bailey 2-0640-40A DIP Switch Configuration Error”
- IR 2439302, “Unexpected Alarm 902-6 H-3 FW Control System Trouble”

- IR 2449353, “Found Loose Terminal / Wire (U2 ASD)”
- IR 2456358, “Spare Card Installed in Bailey Feedwater System”
- IR 2479908, “Bailey Workstation Cables Connected Using Zip-Ties”
- IR 2483696, “Message on Bailey Panel”
- IR 0130067, “Revision of FWLC EPU Tuning Procedure, SP 02-07-008”
- IR 0175371, “FW sys control alarm”
- IR 0198775, “FWLC EC to Modify Setpoint Setdown Missed Low Limit”
- IR 0207013, “FWRV Response While Starting 3A RFP”
- IR 0447627, “FWLC Backup Processor Failure”
- IR 0491510, “Reactor Water Level Swings”
- IR 0675192, “U3 Feedwater Panel Trouble – ‘Slave Fail’”
- IR 0680621, “FWLC Cards Found Not Locked Down”
- IR 0682363, “FWLC CPU HP 1-4-2, 3 Red Failure Light”
- IR 0887887, “FWLC Backup Processor Failure”
- WO 1065802, “U3 Feedwater Panel Trouble – ‘Slave Fail’”
- WO 1077610, “IMD Will Perform Cleaning of the 902-18 Panel”
- WO 1198944, “D2 6Y PM Replacement of Power Supplies”
- WO 1278709, “D2 6Y Bailey Feedwater Supply Replacement”
- WO 1486220, “D2 RFL PM Clean FWLC Panel 902-18 and Check Connection”
- WO 1801088, “Assist system engineer with highlighted portions of complex troubleshooting plan that include voltage readings and setup of DL750 recorders to monitor Bailey power distribution bus and common grounding bus.”
- WO 1811195, “U3 FWLC DIP Switch Config & Ribbon Cable Replacement”
- WO 1287572-01, “IMD Will Perform Cleaning of the 902-18 Panel”
- Commonwealth Edison Company, Mod. No. M12-2-97-006, DCP No. 3700244, Revision 0, September 1997
- Work Planning Instructions for EC 401552, Rev 000, “Remove Spare Analog Slave Output Module Card UY-2-0604-80B
- Vendor Manual, “Bailey Infi 90”
- MRC package for review of RCR 2437067, dated March 27, 2015

LERs:

- 97-010, Docket 50-237, “Feedwater Transient Results in Manual Reactor Scram Due to Operating Team Knowledge Weakness and Operator Weakness While Performing Manual Level Control”
- 237/2001-002-00, “Reactor Scram Due to Reactor Recirculation Pump Trip”
- 237/2003-003-00, “Unit 2 Reactor Feedwater Pump Trip and Automatic Reactor Scram”
- 237/2007-002-00, “Unit 2 Reactor Scram Due to Loss of Feedwater”

Drawings:

- 12E-2750B, Wiring Diagram, Feedwater Power Panel 902-18, Part 4
- 12E-2419, Schematic Diagram Feedwater Control System Reactor Level
- 12E-2419, Wiring Diagram Feedwater Control System 640-80A A/I Module
- 12E-2419, Wiring Diagram Feedwater Control System 640-80B A/O Module
- IR 2514759, “CFAM Elevation Documenting FME Gaps”
- IR 2513207, “No O2 Reading Locally or in Control Room”
- IR 2509849, “Common Cause ACE Requested for Critical Component Failures”
- IR 2508532, “Increase in WGES being Returned from MRC”
- IR 2457402, “Spike Noticed in Megawatts Electric”

- IR 2451316, “2A ASD 3-Way Temp. Reg. Valve Leaking”
- IR 2448502, “Power Suppression Test Load Profile Lessons Learned”
- IR 2439440, “U3 DW Beta Increasing Trend”
- IR 2434065, “U3 Offgas XE-138 / XE-133 Ration < Goal & XE-133 > 2 Increase”
- IR 2431672, “U3 DW %O2 Slow Trend Up”
- IR 2381873, “2/3 EDG “A” SAC Has a Low High End Pressure”
- Risk Assessment Number DRE-3-2015-0189 Rev. 0, “ODM for U3 Midcycle (IR 2434697)”
- OP-AA-108-111, Adverse Condition Monitoring and Contingency Plan, Revision 9, “U3 Increased Core Flow Usage With Failed Fuel, Rev 1,” dated February 4, 2015
- OP-AA-108-111, Adverse Condition Monitoring and Contingency Plan, Revision 9, “Feedwater Reg Valve Oscillations Have Increase and Valve Movement Has Doubled,” dated January 20, 2015
- OP-AA-108-111, Adverse Condition Monitoring and Contingency Plan, Revision 9, “U3 Failed Fuel Monitoring Plan, Rev 0,” dated January 9, 2015
- NF-AA-430, “Failed Fuel Action Plan,” Revision 13
- NF-AB-400-1000, “BWR Fuel Integrity Monitoring,” Revision 4
- Memorandum from J. Tubergen, NF BWR Fuel Reliabilty Engineer to W. Matos, Failure Modes and Effects Analysis of the fuel failure identified on January 8, 2015

<u>4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)</u>

- LER 237/2015-001-00, “Unit 2 Scram Due to Feedwater Level Control Issues”
- EN 50733, “Dresden Unit 2 was Manually Scrammed by Operators due to a Reactor Water Level Transient”
- IR 1699697, “Unexpected U2 FWLC Alarm (U2-DI040 Backup MFP Bad Status)”
- IR 2394030, “U2 FWLC Alarm 902-6 H-3 Due to D.C.S. Failure”
- IR 2437033, “U2 Scram”
- IR 2437067, “FWLC 2-6040-33 Failed; Resulting in Loss of Bailey”
- IR 2436993, “U2 FW Control System Trouble”
- IR 2436166, “FW Control System Trouble Alarm”
- IR 2437086, “Support for Snubber 2-3004G-07 Separated From Wall”
- IR 2437088, “Support for Snubber 2-3004J-03 Separated From Wall”

<u>4OA5 Other Activities</u>

IR 2421154; “HI-STORM/HI-TRAC URI Position”

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agencywide Document Access Management System
ADS	Automatic Depressurization System
AR	Action Request
ATWS	Anticipated Transient Without Scram
AV	Apparent Violation
BWR	Boiling Water Reactor
CAP	Corrective Action Program
CCCG	Common Cause Component Group
CCDP	Conditional Core Damage Probability
CCF	Common Cause Failure
CCG	Common Cause Group
CCSW	Containment Cooling Service Water
CFR	*Code of Federal Regulations*
DIP	Dual In-Line Package
DNMS	Division of Nuclear Materials Safety
DNPS	Dresden Nuclear Power Station
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPU	Extended Power Uprate
EPZ	Emergency Planning Zone
ERI	Energy Research, Inc. (NRC contractor)
ERV	Electromatic Relief Valves
ESF	Engineered Safety Feature
ET	Exposure Time
FME	Foreign Material Exclusion
FMEA	Foreign Material Exclusion Area
FSAR	Final safety Analysis Report
FWLC	Feedwater Level Control
HPCI	High Pressure Coolant Injection
HI-STORM	Storage cask
HI-TRAC	Transfer cask
IMC	Inspection Manual Chapter
I/O	Input/Output
IC	Isolation Condenser
IF	Ignition Frequency
INL	Idaho National Library
IORV	Inadvertent Open Relief Valve
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Inspection Report
IST	In-Service Testing
LERF	Large Early Release Frequency
LER	Licensee Event Report
LLC	Limited Liability Corporation
LOCA	Loss-of-Coolant Accident
LOCHS	Loss of Condenser Heat Sink

LOOP	Loss of Offsite Power
LPCI	Low-Pressure Coolant Injection
MB1	Main Bearing 1
MCC	Motor Control Center
MCID	Materials Control, ISFSI and Decommissioning
MCR	Main Control Room
MFP	Multi-Functional Processor
MFW	Main Feedwater
MPC	Multi-Purpose Canister
MSPI	Mitigating Systems Performance Index
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OWA	Operator Work Around
PARS	Publicly Available Records System
PI	Performance Indicator
PM	Planned or Preventative Maintenance
PMID	Preventive Maintenance Identification Number
PRA	Probabilistic Risk Assessment
RASP	Risk Assessment Standardization Project
RCR	Root Cause Report
RCS	Reactor Coolant System
REMP	Radiological Environmental Monitoring Program
RFP	Reactor Feed Pumps
RWCU	Reactor Water Cleanup
SAPHIRE	Systems Analysis Programs for Hands-on Integrated Reliability Evaluations
SBLC	Standby Liquid Control
SSC	Structure, System, and Component
SBO	Station Blackout
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analysts
SRV	Safety Relief Valve
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Vdc	Volts Direct Current
WO	Work Order

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Sincerely,

/RA/

Anne T. Boland, Director
Division of Reactor Projects

Docket Nos. 50–237, 50–249; 72–037
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