UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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August 2, 2012

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO), Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000254/2012003 AND 05000265/2012003

Dear Mr. Pacilio:

On June 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on July 10, 2012, with T. Hanley, and other members of your staff.

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

One NRC-identified and two self-revealed findings of very low safety significance (Green) were identified during this inspection. These findings were determined to involve violations of NRC requirements. Further, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2 of the Enforcement Policy.

If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region III, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Quad Cities Nuclear Power Station. If you disagree with a cross-cutting aspect assignment in this report, 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 Quad Cities Nuclear Power Station.

In accordance with 10 CFR 2.390 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 Public Document Room or from the Publicly Available Records System (PARS) component of the NRC's Agencywide Document 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/

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

Docket Nos. 50-254 and 50-265
License Nos. DPR-29 and DPR-30

Enclosure: Inspection Report 05000254/2012003 and 05000265/2012003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29, DPR-30
Report No:	05000254/2012003 and 05000265/2012003
Licensee:	Exelon Generation Company, LLC
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, IL
Dates:	April 1 through June 30, 2012
Inspectors:	J. McGhee, Senior Resident Inspector B. Cushman, Resident Inspector E. Sanchez-Santiago, Reactor Inspector R. Orlikowski, Project Engineer A. Shaikh, Reactor Inspector D. Jones, Reactor Inspector C. Mathews, Illinois Emergency Management Agency
Approved by:	Mark Ring, Branch Chief Branch 1 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000254/2012003, 05000265/2012003; 04/01/12 - 06/30/12; Quad Cities Nuclear Power Station, Units 1 & 2; Outage Activities and Other Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Three Green findings were identified by the inspectors. The findings were considered non-cited violations (NCVs) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A finding of very low safety significance with an associated NCV of TS 5.4.1.a, “Procedures,” was self-revealed on March 24, 2012, when operators energized an electrical bus in the switchyard with a grounding device still installed on that bus. Failure of a transmission maintenance supervisor to implement the requirements of OP-AA-109-101, “Clearance and Tagging,” and have operations place a danger tag on a grounding strap installed on 345 kV Bus 9 resulted in a significant voltage perturbation and operating transient on Unit 1. The licensee entered the issue in the CAP as IR 1345302 and immediate actions included clearing the fault and restoring plant equipment. Individual qualifications were removed for parties involved in the event, and a root cause evaluation was performed.

  The finding was determined to be more than minor because it impacted the Human Performance attribute of the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the Human Performance attribute was challenged because the human error resulted in a voltage transient that produced an operational transient on Unit 1 and could have resulted in a more severe challenge to both units. The inspectors performed a SDP Phase 1 screening for the finding using IMC 0609, Table 4a, for the Initiation Events Transient Initiators and determined that the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The duration of the event, separation of divisional and emergency power supplies, and redundancy of equipment supplying safety functions were considered for this determination. Therefore, the finding screened as Green, or very low safety significance. The inspectors identified that this finding has a cross-cutting aspect in the area of Human Performance - Decision Making because both the station supervisor overseeing the electrical bus realignment and the clearance holder took action based on non-conservative assumptions that could easily have been validated before placing the electrical system at risk (H.1(b)).
  (Section 1R20.1)

- Green. A self-revealed finding of very low safety significance with an associated NCV of Technical Specification (TS) 3.7.7, "Main Turbine Bypass Valves System," was identified on April 18, 2012, when an unplanned reactor scram occurred during generator voltage regulator testing. Inspectors subsequently determined the licensee had failed to identify elimination of a time delay that changed how the system responded to a load reject with no turbine trip during vendor design documentation review for the digital electro-hydraulic control (DEHC) system modification implemented in 2006. Failure to perform the review with the rigor required by CC-AA-103-1003, "Owner's Acceptance Review of External Engineering Technical Products," is a performance deficiency entered into the licensee's corrective action program (CAP) as Issue Report (IR) 1355763. This finding resulted in exceeding the allowed out-of-service time for TS 3.7.7, "Main Turbine Bypass System," on at least eleven occasions between the two units since the modifications were installed.

  The finding was determined to be more than minor because the performance deficiency adversely affected the Reactor Safety - Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. In this circumstance, the Design Control attribute of the cornerstone was adversely impacted when unintended consequences were introduced during a modification. Using IMC 0609, Attachment 4, Table 4a, Initiating Events Cornerstone, Transient Initiators, inspectors determined that the performance deficiency did not contribute to the likelihood of both a reactor trip and unavailability of mitigation equipment since the main steam safety and relief valves are the credited pressure mitigation equipment and were unaffected by the event. Therefore, this finding screens as Green, or very low safety significance. The inspectors did not identify a cross-cutting aspect for this performance deficiency since it occurred during the DEHC modification review in 2006 and was considered a legacy issue. (Section 4OA3.4)

Cornerstone: Mitigating Systems

- Green. An NRC-identified finding of very low safety significance with an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Procedures," was identified on March 27, 2012, when station employees did not adhere to station seismic controls while performing Unit 2 outage work. Failure to implement the requirements of the seismic procedure was a performance deficiency. In placing the stacked Unit 2 high pressure coolant injection turbine steam chest too close to the Unit 1 high pressure coolant injection pump and piping, technicians circumvented administrative controls in place to prevent unrestrained equipment from impacting safety-related equipment during a seismic event. The licensee subsequently secured the assembly per the procedure. This issue was entered into the licensee's corrective action program as IR 1358458.

  The finding was determined to be more than minor because it adversely affected the equipment reliability attribute of the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage). This finding was assessed using the Phase 1 screening worksheets of IMC 0609 and determined to be of very low safety significance (Green). The finding did not result in an actual loss of safety function of a single train for greater than the TS allowed outage time. The finding did not involve a total loss of any safety function, as identified by the licensee through a Probabilistic Risk Assessment, Individual Plan Examination of External Events, or similar analysis, contributing to external event-initiated core damage accident sequences (i.e., initiated by a seismic, flooding, or severe weather event). The inspectors identified a cross-cutting aspect in the area of Human Performance - Resources because the licensee did not ensure that the work package included sufficient information to ensure that the cribbing used for the activity met the requirements specified by engineering in the analyzed load movement plan (H.2(c)). (Section 1R20.2)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1

Unit 1 began the period operating at full power with main generator elevated vibration. On April 2, 2012, concurrent inoperability of the Unit 1 and Unit 2 emergency diesel generators (EDGs) required entry into Technical Specifications (TS) 3.8.1, Condition E, and operators began to shut down Unit 1 as required by the TS actions. Additional information regarding this event is provided in Section 4OA3.2 of this report. Power was lowered to 84 percent and held until the Unit 1 EDG was restored to operable status and the shutdown terminated. Power was restored to 100 percent that same evening.

Unit 1 operated at 100 percent thermal power for the remainder of the evaluated period through June 30, 2012, with the exception of planned power reductions for routine surveillances, main condenser flow reversals, planned equipment repair, and control rod maneuvers.

Unit 2

Unit 2 began the inspection period with the reactor shut down for the refueling outage (Q2R21) and in Mode 5. The outage was originally scheduled for 17 days, but was extended to 28 days when emergent repairs were required for a leaking reactor pressure vessel penetration identified during the reactor pressure test after the vessel had been reassembled. Additional discussion of the repair is included in Section 4OA3.3 of this report. Post outage reactor startup began on April 16, 2012. On April 18 with the unit operating at 23 percent power and post-modification voltage regulator load reject testing in progress, the Unit 2 electro-hydraulic control system malfunctioned resulting in a reactor scram on high pressure. Additional discussion of the scram and associated equipment issues is included in Section 4AO3.4 of this report. Reactor startup began on April 19, 2012, with synchronization of the generator to the grid on April 20, 2012, and full power on April 22, 2012.

Unit 2 operated at 100 percent thermal power for the remainder of the evaluated period through June 30, 2012, with the exception of planned power reductions for routine surveillances, main condenser flow reversals, planned equipment repair, and control rod maneuvers.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite 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 offsite power system. Examples of aspects considered in the inspectors' review included:

- The coordination between the TSO and the plant during off-normal or emergency events;
- The explanations for the events;
- The estimates of when the offsite power system would be returned to a normal state; and
- The notifications from the TSO to the plant when the offsite 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 offsite AC power system and the onsite alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- The actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- The 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;
- A reassessment of plant risk based on maintenance activities which could affect grid reliability or the ability of the transmission system to provide offsite power; and,
- The 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 offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01-05.

b. Findings

No findings were identified. Section 1R20.1 of this report has a review of a grounded bus and associated interface problems with grid maintenance personnel. This review identified some assumptions made by both parties during communication concerning a maintenance activity with potential impact to electrical grid availability.

.2 Summer Seasonal Readiness Preparations

a. Inspection Scope

The inspectors performed a review of the licensee's preparations for summer weather for selected systems, including conditions that could lead to an extended drought.

During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to mitigate or respond to adverse weather conditions. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection, and verified that operator actions were appropriate as specified by plant specific procedures. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into the corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Reactor building closed-loop cooling water temperature control, and
- Control rod drive pumps and spare parts inventory.

This inspection constituted one seasonal adverse weather sample as defined in IP 71111.01-05.

b. Findings

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:

- Unit 2 emergency diesel generator after extensive troubleshooting and testing;
- Unit 1 reactor building closed-loop cooling water system;
- Safe shutdown makeup pump and system standby lineup; and
- Unit 1 reactor core isolation cooling system with Unit 1 high pressure coolant injection (HPCI) system out of service for planned maintenance.

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 four partial system walkdown samples 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 1.1.2.1, Unit 2 Reactor Building, Elevation 544’-0”, Torus Area and Top of Torus;
- Fire Zone 1.1.1.3, Unit 1 Reactor Building, Elevation 623', Mezzanine Level;
- Fire Zone 1.1.1.4, Unit 1 Reactor Building, Elevation 647', Third Floor;
- Fire Zone 6.2.A, Unit 2 Turbine Building, Elevation 615’-6”, ‘A’ Battery Charger Room Unit 2;
- Fire Zone 6.2.B, Unit 2 Turbine Building, Elevation 615’-6”, ‘B’ Battery Charger Room Unit 2; and
- Fire Zone 7.2, Unit 2 Turbine Building, Elevation 628’-6”, 250V Battery Room.

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 six quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On June 11, 2012, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification examinations 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 sample as defined in IP 71111.11.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

Inspectors observed the following operator activities in the main control room that required heightened awareness or were related to increased risk during the inspection period:

- On April 16, 2012, inspectors observed the Unit 2 startup, approach to criticality, and establishment of an initial heat-up rate following the Unit 2 refueling outage.
- On April 16, 2012, inspectors observed the response of licensed operators in the control room to an unexpected half scram caused by a momentary spike from a local power range monitor.

The inspectors evaluated the individual operator and crew performance in the following areas during the control room monitoring:

- 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 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 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.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Z0200: Nuclear Boiler; and
- Z0203-1: Main Steam Isolation Valves (MSIVs).

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 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:

- Refueling outage week 3 (Emergent Unit 2 emergency diesel generator (EDG) voltage regulator replacement, switchyard activities, post assembly leak check of MSIVs, secondary containment breach, and reactor vessel instrument penetration repair);
- Verification of Unit 1 protected equipment pathways (week of April 23, 2012);
- Work week 12-19-7 schedule and implementation activities (Bus 23-1 second level undervoltage testing, 1A residual heat removal [RHR] pump breaker maintenance, 1B RHR service water [RHRSW] room fan cooler motor maintenance, 1A RHRSW vault submarine door maintenance and pressure test, switchyard work for a line outage and open ring bus, emergent repair to RHR heat exchanger service water relief valve inlet elbow); and
- Emergent work to Unit 1 HPCI bolted steam connection and Unit 2 EDG cooling water pump cubicle cooler fan motor on May 17, 2012.

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.

Specific 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

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- Issue Report (IR) 1349496: Unit 2 DGCWP [diesel generator cooling water pump] Room Cooler Fan ‘A’ Breaker Thermal Overloads Tripped;
- IR 1351413: MCC [motor control center] 28/29-5 Swapped to Bus 28 During QCOS 6600-48;
- Engineering Change (EC) 388804: Turbine Bypass Valves Operability at Low Reactor Power Levels;
- EC 389153: Review Degraded Grease in Merlin Gerin Circuit Breakers;
- IR 1366596: Level Switch Failed to Reset; and
- IR 1377859: DPIS [differential pressure indicating switch] 1-0261-34A Sticky at Around 2.5 psig.

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, TS bases 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.

This operability inspection constituted six samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification(s):

- EC 388685: Relocate Unit 2 ISOC [isochronous] Contact to Fast Start Relay; and
- EC 388628: Half Nozzle Repair for N11B.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the plant modification with Operations and Engineering to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

This inspection constituted two plant modification samples as defined in IP 71111.18-05.

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 activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Work Order (WO) 1523860: ECCS (emergency core cooling systems) and EDG Auto Start Test Aborted;
- QCOS 6600-48: Unit 2 Division II Emergency Core Cooling System Simulated Auto Activation and Diesel Generator Auto-Start Surveillance;
- QOS 6500-04: 4kV Bus 23-1 Undervoltage Functional Test;
- QCTS 0600-11: HPCI Steam Supply Local Leak Rate Test (MO-1(2)-2301-4, MO-1(2)-2301-5);
- QCOS 0201-08: Reactor Vessel Class 1 and Associated Class 2 System Leak Test;

- Re-performance of QCOS 0201-08: Reactor Vessel Class 1 and Associated Class 2 System Leak Test for N111B ASME Code Repair (after leak repair); and
- QCOS 2300-07: HPCI System Turbine Overspeed Test.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): the effect of testing on the plant had been adequately addressed; testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness; test instrumentation was appropriate; tests were performed as written in accordance with properly reviewed and approved procedures; equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion); and test documentation was properly evaluated. The inspectors evaluated the activities against TSs, the UFSAR, 10 CFR Part 50 requirements, licensee 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 post-maintenance 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 seven post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

This inspection was continued from the previous reporting period (January 1 through March 31, 2012). Numerous inspection activities and a partial inspection sample for the Unit 2 refueling outage (RFO), which started on March 19, 2012, were documented in Inspection Report 50-254/2012002; 50-265/2012002.

During this portion of the RFO, the inspectors monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the safe shutdown management plan (SSMP) for key safety functions and compliance with the applicable TS when taking equipment out of service;
- implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing;
- installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and accounting for instrument error;

- controls over the status and configuration of electrical systems to ensure that TS and SSMP requirements were met, and controls over switchyard activities;
- monitoring of decay heat removal processes, systems, and components;
- controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system;
- reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss;
- controls over activities that could affect reactivity;
- maintenance of secondary containment as required by TS;
- licensee fatigue management, as required by 10 CFR 26, Subpart I;
- refueling activities, including fuel handling and sipping to detect fuel assembly and control rod blade leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, and walkdown of the drywell (primary containment) to verify that debris had not been left which could block emergency core cooling system suction strainers; and
- licensee identification and resolution of problems related to RFO activities.

Documents reviewed during the inspection are listed in the Attachment to this report.

This inspection constituted one RFO sample as defined in IP 71111.20-05.

b. Findings

(1) 345 kV Bus Energized with Ground Device Installed

Introduction: A Green finding was self-revealed on March 24, 2012, when operators closed a disconnect switch in the switchyard onto a bus with a grounding device still installed on that bus. The grounding device was installed on 345 kV Bus 9 by maintenance technicians without the device having been tagged for equipment control as required by OP-AA-109-101, “Clearance and Tagging.” This resulted in a voltage transient on Unit 1. Unit 2 busses saw the same transient but were not adversely impacted. The transient sequence and inspectors’ review of operator actions for this event were previously reported in Integrated Report 05000254/2012002; 05000265/2012002 in Section 4OA3.1. Pursuant to 10 CFR 50.73(a)(1), this event was reported by the licensee via telephone notification for an invalid actuation in lieu of a written licensee event report (LER) on April 30, 2012.

Description: Work activities in the Quad Cities switchyard during March 2012 were performed by both station personnel and by personnel from the Commonwealth Edison grid maintenance organization. Coordination of work activities between these groups was controlled by OP-AA-108-107-1002, “Interface Procedure between ComEd/PECO and Exelon Generation (Nuclear/Power) for Transmission Operations.” This procedure states that station operations will use the ComEd/PECO Tag Out procedure for equipment under the control and operating authority of the transmission system operator. The procedure also states both organizations will use the Exelon Generation clearance procedure (OP-AA-109-101) for equipment under the control and operating authority of the station. Step 4.6.5 of the interface procedure requires both parties to review, coordinate, and assure correctness of the tagout when clearance points cross authority boundaries.

Multiple station clearance orders, prepared in accordance with OP-AA-109-101, were used to provide the appropriate zone of protection for the various bus and transmission work activities. In addition, boundary changes for these clearance orders were incorporated into the schedule to support testing as portions of the system were returned after maintenance. Per the procedure requirements, transmission maintenance supervisors signed on as clearance holders for work activities for which they were responsible. Clearance Order 95505 was one of the tagouts in place as part of the switchyard work that established the zone of protection for work on the reserve auxiliary transformer, T-22. During normal operation, T-22 provided offsite power to the safety-related electrical busses of Unit 2. Transmission maintenance supervisors were signed onto this clearance as holders.

In the early morning hours of March 24, 2012, the day shift transmission supervisor installed grounds on Bus 9 to protect workers performing a preventative maintenance task on the Bus Tie 9-10 disconnect switch. The grounds were placed within the zone of protection established for Clearance Order 95505, but a danger tag was not hung on the grounds as required by OP-AA-109-101. OP-AA-109-101 states that if additional grounds are identified to be required after the start of work, then operations must be contacted to danger tag the additional grounds. Because the new grounds were installed within the station clearance boundary, the requirements of OP-AA-109-101 were required to be satisfied. However, the transmission supervisor logged placement of the ground in the workers alteration log as would have been allowed by OP-AA-108-107-1002 for work on Bus 9 itself. When the work progress required the station tagout protection boundaries to be changed, communication between the maintenance supervisor and the station supervisor in charge of the boundary swap were not extensive enough to identify the ground device. The operations supervisor implementing the change assumed all grounds were removed even though he knew that the grid maintenance practice allowed use of undispatched grounds to protect workers. The maintenance supervisor did not understand that as part of the switching, line 0402 would be closed in to the bus and assumed he could leave the grounds in place. The maintenance supervisor released the tagout to support the boundary swap, leaving the grounding device hanging on the bus. Operators were dispatched to perform the boundary swap, and although they checked for grounding devices before manipulating components, they did not identify the presence of the grounding device in the low light conditions. When the operator closed the disconnect, energized 345 kV line 0402 was closed onto a grounded Bus 9. Switchyard protective schemes isolated the fault, but not before a significant voltage transient occurred on the ring bus.

For Unit 1, the voltage transient resulted in a half-scram, low voltage on Bus 18 and an increase in main generator bearing vibration. The low voltage condition on Bus 18 caused several trips, actuations, and isolations. Several feedwater heater level control valves were unlatched, and in response to the partial loss of feedwater heating, operators implemented the abnormal procedure actions including lowering reactor power to 90 percent of rated to stabilize the unit. Additional trips on Bus 18 low voltage signals further complicated the event for the operators. Reactor protection system ‘A’ motor generator set tripped during the voltage transient, resulting in an invalid actuation signal which caused the half-scram signal and containment isolation valves for multiple systems to close, as designed. In addition, the Unit 1 emergency core cooling system keep-fill pump tripped. The pump trip was quickly followed by a low discharge pressure alarm in both the 2A and 2B core spray systems. Operators promptly restored the keep-fill pump and vented affected systems with no loss of operability. Unit 1 main turbine vibration on generator bearings 9 and 10 was elevated after the event and remained at 6.0 and 7.0 mils respectively after conditions in the secondary plant stabilized.

The licensee entered the event into the CAP as IR 1345302 and initiated a root-cause investigation. The licensee identified two root causes for the event. First, switchyard interface procedural guidance for transmission workers in the switchyard was not clear as to whether those non-station personnel can work under a station clearance order on transmission department equipment and did not provide instructions for how to perform that activity. The second root cause identified by the licensee addressed the operators' failure to identify the installed ground strap before the disconnect switch was closed. The licensee determined that the briefing provided to the operators to perform the boundary swap did not provide adequate guidance for safe execution of the evolution.

<u>Analysis</u>: Failure to implement the procedural requirements of OP-AA-109-101 is a performance deficiency and a finding. A maintenance technician working on an out of service electrical bus in the switchyard installed a ground strap on the bus but did not have the ground tagged as required by station procedure. The finding was compared to the insignificant procedural error examples provided in Appendix E of IMC 0612 and determined to be sufficiently dissimilar from those examples due to the event resulting in an operational transient on Unit 1. The finding was determined to be more than minor because it impacted the Initiating Events Cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the Human Performance attribute of the cornerstone was challenged because the human error resulted in a voltage transient that produced an operational transient on Unit 1 and could have resulted in a more severe challenge to both units.

The inspectors performed a Significance Determination Process Phase 1 screening for the finding using IMC 0609, Table 4a, for the Initiating Events Transient Initiators and determined that the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The short duration of the event, separation of divisional and emergency power supplies, and redundancy of equipment supplying safety functions were considered for this determination. Therefore, the finding screened as very low safety significance or Green.

The inspectors identified that this finding has a cross-cutting aspect in the area of Human Performance - Decision Making because both the station supervisor overseeing the electrical bus realignment and the maintenance technician took action based on non-conservative assumptions that could easily have been validated before placing the electrical system at risk (H.1(b)).

<u>Enforcement</u>: Technical Specification 5.4.1.a, "Procedures," requires in part that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.

Regulatory Guide 1.33, Revision 2, Appendix A lists Equipment Control (e.g. locking and tagging) procedures as one of the applicable procedures required. OP-AA-109-101, "Clearance and Tagging" is one of the administrative procedures that accomplished this requirement. Step 7.3.10.1 of the procedure states that all grounding devices providing personnel protection shall be included as an isolation point on a clearance order and will be tagged with a danger tag that is hung on the grounding strap, the cubicle door, or on the ground test device in an appropriate location (such as the racking screw or front panel).

Contrary to this procedure requirement, a switchyard maintenance supervisor installed a ground strap on Bus 9 that did not have a danger tag. The grounding strap was installed within the zone of protection of station clearances for the out of service bus and was not removed before the bus was energized, resulting in a voltage switchyard transient and plant transient on Unit 1, as previously described. Because this violation was of very

low safety significance and it was entered into the licensee's corrective action program as IR 1345302, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000254/2012003-01; 05000265/2012003-01 "Bus Energized with Grounding Device Installed").** The grounding device was subsequently removed and equipment repairs completed before the bus was re-energized to supply Transformer T-22.

(2) Procedure Non-compliance Impacting HPCI Reliability

Introduction: An NRC-identified finding of very low safety significance (Green) and associated non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Procedures," was identified on March 27, 2012, when station employees did not implement the station seismic control procedure when they staged the Unit 2 high pressure coolant injection (HPCI) turbine valve chest too near to the Unit 1 HPCI pump and piping, exposing the safety-related system to potential failure during a seismic event.

Description: Overhaul of the Unit 2 HPCI turbine was performed during the refueling outage using Work Order (WO) 08880895, HPCI TBN DISMANTLE. Step MM 17 of the WO performed rigging and removal of the control valve steam chest referencing MA-AA-716-021, "Rigging and Lifting Program for rigging requirements." Work instructions within that step had mechanics "transport the steam chest to a suitable work area" and "support the steam chest on cribbing to allow the control valves to hang free." Prior to the refueling outage, engineering provided an approved heavy load plan to remove, repair, and re-install the steam chest. Engineering Change Request (ECR) 404324 analyzed movement of the manifold over the Unit 2 turbine and piping to the concrete floor south of the Unit 2 HPCI turbine. The ECR stated that the rigging equipment was to be rated for 10,000 lbs (twice the 5,000 lb weight of the manifold) and redundant rigging was utilized.

On March 27, 2012, during a plant tour, inspectors questioned placement of the Unit 2 (shutdown unit) HPCI turbine valve steam chest in the Unit 1 (online unit) HPCI room. Specifically, inspectors questioned the potential impact of a seismic event on the Unit 1 HPCI system due to the proximity of the assembly and cribbing to the Unit 1 HPCI pump and piping. The inspectors were initially informed that the steam chest had been positioned in accordance with the heavy load movement plan documented in ECR 404324, and the station seismic housekeeping procedure, MA-QC-716-026-1001.

When inspectors' questions for clarification persisted, station engineering personnel performed a plant walkdown with the procedure and again determined that the procedure requirements were satisfied because "the manifold was at least twelve inches away from the safety related equipment." However, at that time engineering directed maintenance personnel to attach a chain to secure the top of the manifold to the 7.5 ton overhead crane to mitigate "tipping." Following additional questioning from the inspectors the next day, station personnel reattached the redundant rigging previously used to move the manifold by the rigging plan. Engineering personnel again reinforced that the station was in compliance with the procedure and that engineering judgment supported placement of the manifold a minimum of 15 inches away from any safety-related component. Engineering documented this position in ECR 404530, "Review of Seismic Housekeeping in Unit 1 HPCI Room," on March 29, 2012, concluding the following:

- placement of the assembly on two 12-inch by 12-inch blocks of wood, the cribbing was considered rigid for seismic consideration;
- the weight of the manifold and blocks would prevent movement during a safe shutdown earthquake; and
- if the cribbing did fall, the assembly would be suspended by the overhead crane via the redundant rigging.

Inspectors reviewed ECR 404530 against the procedural requirements of MA-QC-716-026-1001. Additionally, inspectors measured the height of the steam chest and cribbing (54 inches), the width of the assembly (54 inches), and the distance from the assembly to the safety-related equipment (15 inches.) The procedure specifies the following:

- Step 4.1.2 states in part, "Objects should not be considered to be free from seismic movement solely on their mass since accelerations causing the movement are independent of the size or weight of the object."
- Step 4.2.2.1 is intended to address sliding of the object and states in part, "A minimum of 12 inches shall be provided between an unsecured item and a safety-related component provided the item cannot overturn or collapse. This is a minimum and should never be used unless other options (relocation or restraint) are not feasible."
- Step 4.2.3 addresses the potential for the object overturning and states in sub-step 3, "For those item that do not meet this criterion for stability [as described in sub-step 2, placing the object on cribbing makes the rest of this statement applicable] the projected fall distance shall be determined based on the height plus a minimum of 1 foot. This is the minimum dimension to be used for determining clearance from safety-related components and shall be increased as much as possible to eliminate any interaction potential."

The inspectors measured the stacked components to be 54 inches high, which required the component to be more than 66 inches away from the safety-related equipment being relied on for safe shutdown of Unit 1 or to be secured in a manner that would have prevented overturning. The steam chest and cribbing were not secured together, and the assembly was not restrained to prevent overturning until prompting from inspectors. Inspectors determined that when the licensee secured the assembly to a seismically qualified support with redundant rigging, the assembly was then in compliance with the station procedure and operability of the Unit 1 HPCI was no longer in question. Since all actions took place in a 3-day time frame with no other Unit 1 equipment inoperable, inspectors determined that Unit 1 TS were not violated. The licensee entered the issue in the CAP as IR 1358458.

Additionally inspectors reviewed the heavy load movement plan in more detail. As stated previously, the heavy load plan, ECR 404324, specified that the cribbing requirements in EC 335248 be followed. EC 335248 authorized work on the manifold over the grating on the north end of the Unit 2 HPCI turbine. The ECR required diamond decking be placed over the grating, 4-inch by 4-inch posts were used to reinforce the installed grating supports and 6-inch by 6-inch beams at least 6 foot in length were placed over the diamond decking directly over the support beams. Contrary to the cribbing and placement description in this EC, inspectors identified that in 2012 the manifold had been placed on the concrete at the south end of the HPCI pump on 12-inch by 12-inch blocks of wood for a combined cribbing height of 24 inches.

Analysis: Failure to implement the requirements of the seismic housekeeping procedure was a performance deficiency. In placing the stacked equipment too close to the Unit 1 HPCI components, the technicians circumvented the administrative controls in place to prevent the unrestrained equipment from impacting the safety-related equipment during a seismic event. The finding was compared to the insignificant procedural error examples provided in Appendix E of IMC 0612 and determined to be sufficiently dissimilar from those examples due to the nature and unpredictability of the seismic event. The finding is more than minor because it adversely affected the equipment reliability attribute of the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems responding to initiating events to prevent undesirable consequences (i.e., core damage).

This finding was assessed using the Phase 1 screening worksheets of IMC 0609 and determined to be of very low safety significance (Green). The finding did not result in an actual loss of safety function of a single train for greater than the TS allowed outage time. The finding did not involve a total loss of any safety function, as identified by the licensee through a Probabilistic Risk Assessment (PRA), Individual Plan Examination of External Events (IPEEE), or similar analysis, contributing to external event-initiated core damage accident sequences (i.e., initiated by a seismic, flooding, or severe weather event).

The inspectors identified a cross-cutting aspect in the area of Human Performance - Resources because the licensee did not ensure that the work package included sufficient information to ensure that the cribbing used for the activity met the requirements specified by engineering in the analyzed load movement plan (H.2(c)).

Enforcement: Title 10 CFR 50, Appendix B, Criterion V states, in part, that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures.

MA-QC-716-026-1001, “Seismic Housekeeping,” provided instructions to prevent temporarily stored or transient materials from adversely impacting safety-related components required for safe shutdown of the plant or continued decay heat removal during or following a seismic event. Step 4.2.3 of that procedure addressed the potential for the object overturning and stated in sub-step 3 that the projected fall distance for unsecured, stacked items was determined based on the height plus a minimum of 1 foot. Step 4.2.3.4 required stacked items to be secured together and or relocated a safe distance away from safety-related equipment or components since the potential interaction distances for loose items would be difficult to predict. Step 4.2.3.5 required restraints where safe distances could not be maintained for unstable items.

Contrary to the above, on March 27, 2012, inspectors identified that maintenance did not implement the requirements of MA-QC-716-026-1001, “Seismic Housekeeping,” while performing the overhaul of the Unit 2 HPCI turbine. Specifically, maintenance placed the Unit 2 HPCI turbine steam chest on cribbing within 15 inches of the Unit 1 HPCI pump and piping in the adjacent room and did not restrain the assembly as required by the procedure. Because this violation was of very low safety significance and it was entered into the licensee’s CAP as IR 1358458, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement manual **(NCV 05000254/2012003-02, “Procedure Noncompliance Impacting Reliability of HPCI”).** The licensee secured the assembly to be in compliance with the procedure.

.2 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for an unscheduled maintenance outage that began on April 18, 2012, and continued through April 20, 2012. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The maintenance outage began when the main generator output breakers were opened at 23 percent power for testing and the turbine electrohydraulic control system could not control reactor pressure (see Section 4OA3 of this report for more information on the equipment issues that resulted in the reactor shutdown). Following the automatic reactor scram, inspectors observed the cooldown, outage equipment configuration and risk management activities, electrical lineups, control and monitoring of decay heat removal, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage.

This inspection constituted one other outage sample as defined in IP 71111.20-05.

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:

- QCOS 0250-04: MSIV Closure Timing (IST);
- QCOS 1300-05: Quarterly RCIC Pump Operability Test (IST);
- QCOS 2300-01: Periodic HPCI Pump Operability Test (Routine);
- QCOS 1600-07: Reactor Coolant Leakage in the Drywell (RCS); and
- QCOS 1300-07: RCIC Manual Initiation Test (IST).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and 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 USAR, 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 inservice testing 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 and 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 one routine surveillance testing sample, three inservice testing samples, and one reactor coolant system leak detection inspection sample as defined in IP 71111.22, Sections-02 and -05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of two routine licensee emergency drills this quarter. The first was on May 10, 2012, for emergency response organization team ‘D’ and the second for emergency response organization team ‘A’ on June 14, 2012. The purpose of the inspection was to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the control room simulator and the Technical Support Center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the corrective action program. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the Attachment to this report.

This emergency preparedness drill inspection constituted two emergency plan drill samples as defined in IP 71114.06-05.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

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

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage performance indicator for Quad Cities Unit 1 and Unit 2 for the period from April 1, 2011 through March 31, 2012. To determine the accuracy of the performance indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 6, dated October 2009, were used. The inspectors reviewed the licensee’s operator logs, RCS leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of April 1, 2011 through March 31, 2012, to validate the accuracy of the submittals. 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 reactor coolant system leakage samples 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 Physical Protection

.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 that 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: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; 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 followup, 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

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 inspector 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 from December 1, 2011 through June 1, 2012, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues documented outside the normal CAP. Examples include major equipment problem lists, repetitive and/or rework 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 one semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Selected Issue Followup Inspection: Emergency Core Cooling Systems and Emergency Diesel Generator Auto Start Test Aborted (IR 1348778)

a. Inspection Scope

During a review of items entered into the licensee's CAP, the inspectors recognized a corrective action item documenting failure of the Unit 2 EDG to maintain voltage as expected during the outage performance of QCOS 6600-48, "ECCS, and EDG Auto Start Surveillance," on April 1, 2012. When the machine failed to automatically correct voltage drops that occurred due to starting large loads, operators took action to manually raise voltage to prevent damage to running equipment. The machine was shut down and declared inoperable.

The EDG had been operated earlier that same shift for QCOS 6600-39, "Unit 2 Emergency Diesel Generator Largest Load Reject Surveillance," with no anomalies identified in the voltage regulation. Inspectors reviewed computer data and other information obtained during the maintenance and testing activities preceding the failure as well as post-maintenance testing to ensure appropriate equipment operation.

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

b. Findings

No findings were identified.

.5 Selected Issue Followup Inspection: Pressure Boundary Leakage Identified through Instrument Nozzle N-11B (IR 1350193)

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting the identification of pressure boundary leakage during the Unit 2 refueling outage on April 4, 2012. During the post-assembly pressure vessel leak test, leakage was identified on the fourth floor of the drywell, coming from the reference leg inlet nozzle, N-11B. The pressure vessel leak test walkdown was completed with no other discrepancies identified.

The vessel was depressurized, and arrangements were made to facilitate repairs. Repairs were complete on April 15, 2012.

This issue was reported to the NRC as Event Notification 47806. Additional details to this issue are included in the closeout review documentation for LER 05000265/2012-002-00 located in Section 4OA3 of this report.

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

b. Findings

No findings were identified.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) LER 05000254/2012-001-00: Control Room Emergency Ventilation Air Conditioning System Inoperable

This event, which occurred on February 3, 2012, was discovered when control room operators identified that the green indicating light for the 'B' control room heating, ventilation, and air conditioning (HVAC) refrigeration condensing unit (RCU) was not lit as expected. An equipment operator was dispatched to investigate the position of the breaker, and the breaker was found in the tripped position. The tripped breaker rendered the single train safety system inoperable and occurred due to over current. The operating crew declared the 'B' control room HVAC system inoperable and entered the applicable TS requirements. This failure has been classified as a Maintenance Rule functional failure.

On January 20, 2012, a modification was installed to the 'B' Control Room HVAC RCU. This modification installed a feature that would allow the RCU to automatically start multiple times a day in order to evacuate residual refrigerant from the suction. This was done to avoid the formation of liquid refrigerant at the suction or intake of the compressor and cause damage to the RCU. The ‘B’ control HVAC system was successfully run after the completion of this modification. It is believed that an over current condition occurred during one of these pump down cycles. An engineering review was performed to determine if the setpoint of the breaker trips was set appropriately. This review determined that the breaker trip was set at an appropriate setting allowed by the national electric code for a motor of this type at 12 times the full load current. Further calculations determined that the motor for the HVAC compressor could be classified as a “higher locked-rotor current.” With this classification, electrical codes would allow raising the setpoint of the breaker trip to 17 times the full load current. The breaker trip setpoints were raised and verified to remain within industry guidelines to maintain breaker coordination. On February 9, 2012, the ‘B’ control room HVAC system successfully completed a 10 hour confidence run and was declared operable.

Immediate corrective actions were to reset the breaker and initiate the engineering review of the breaker trip setpoints. A previous LER was generated for this same system, (LER 05000254/2011-003-00; 05000265/2011-003-00: Control Room Emergency Ventilation Air Conditioning System Inoperable) that was documented in NRC Inspection Report 05000254/2011005; 05000265/2011005. The circumstances for both events were reviewed by inspectors to ensure the failures were appropriately addressed.

Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

This event followup review constituted one sample as defined in IP 71153-05.

.2 <u>(Closed) LER 05000254/2012-002-00: Standby Gas Treatment System Loss of Safety Function Due to Loss of Emergency Power</u>

This event, which occurred on April 2, 2012, was discovered when a ground appeared on the 125 Vdc system which resulted in an unplanned start of the Unit 1 EDG. The Unit 1 EDG was found running unloaded, without a generator field flash, and with no receipt of an auto start signal. Troubleshooting identified that a ground had developed on the 125 Vdc system. As a result, the Unit 1 EDG was declared inoperable. At this time, Unit 2 was in a refueling outage and the Unit 2 EDG was previously inoperable for maintenance. Due to the simultaneous inoperability of the Unit 1 EDG and the Unit 2 EDG, TS 3.8.1 Condition E was entered for two required EDGs inoperable to Unit 1. Since the Unit 1 and Unit 2 EDGs supply emergency power to both trains of standby gas treatment systems (SBGTS), emergency power was unavailable to SBGTS. The Unit 0 EDG that is shared between Unit 1 and Unit 2 in a swing diesel bus arrangement is not credited to provide emergency power to the SBGTS. After the 2 hour completion time of TS Condition E had expired, the license entered TS 3.8.1 Condition F and began to shutdown Unit 1 to be in Mode 3 in 12 hours.

Troubleshooting identified the 125 Vdc ground on the Unit 1 EDG governor oil booster pump motor. The location of the ground did explain all alarms and indications noted by operations. This motor was replaced and post-maintenance testing was performed for the Unit 1 EDG. Operations declared the Unit 1 EDG operable and exited TS 3.8.1 Condition F. Power was lowered to 84 percent of rated before the diesel was repaired and retested. At that time the shutdown was terminated and Unit 1 reactor power was subsequently returned to 100 percent.

The cause of the 125 Vdc ground was a breach in the insulated sleeve of the brush holder due to previously drilled and tapped holes for fasteners used to secure the motor connection box. These drilled holes allowed the use of long fasteners to penetrate the insulated sleeve of the brush holder and leave an area of the brass brush holder exposed inside to the brush holder bore. This led to electrical arcing and creation of the short-to-ground. This condition was inspected on the other two EDGs as part of the extent of condition review. The motors have been replaced, and the fasteners have been verified for proper length on all three EDGs. The inspectors have determined that the extent of condition and corrective actions have been appropriate for the resolution of this issue.

Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

This event followup review constituted one sample as defined in IP 71153-05.

.3 (Closed) LER 05000265/2012-002-00: Unit 2 Reactor Pressure Vessel Instrument Nozzle Leak

This event, which occurred on April 4, 2012, was discovered while the Unit 2 reactor pressure vessel Class 1 boundary system leakage test was being performed. A leak of 60 drops per minute was identified on the N-11B instrument nozzle located on the fourth floor of the Unit 2 drywell. This nozzle is attached to the wall of the pressure vessel and provides the connection point for the reference leg of the ‘B’ train of the reactor vessel level instrumentation system. Following the test, the vessel was depressurized and the penetration was repaired. The repair, known as a “half-nozzle” repair, included machining a portion of the degraded nozzle from the vessel penetration and rewelding a new N-11B nozzle to the outside of the vessel wall. The repair was performed in compliance with ASME Section XI and resulted in the degraded section of the nozzle remaining installed. A relief request was submitted and approved to allow a postulated worst case flaw to remain in the nozzle remnant during the next 2-year operational cycle. The repair was completed and tested satisfactorily on April 15, 2012.

No violation of NRC requirements has been identified associated with this issue. This issue was identified in Mode 4. In Mode 4, RCS operational leakage limits are not applicable. Leakage was not identified from this location during the Mode 3 walkdown performed by Operations on March 19, 2012, with the reactor vessel still at elevated pressure. There is also no indication that a leak existed at this location during the preceding operational cycle. Unidentified leakage had been increasing during the last half of the operating cycle, to a value near 2 gpm just prior to the refueling outage. There was no corresponding change in containment atmosphere gaseous or particulate activity. The N-11B instrument nozzle communicates with the steam space of the reactor vessel. A leak from the N-11B would contribute to atmospheric activity within containment as well as local area temperatures. Containment gaseous and particulate activity remained low and constant throughout the cycle, and temperatures of the fourth floor of the drywell were consistent with the temperatures recorded on Unit 1. Chemistry sampling of the Unit 2 drywell floor drain sump water in October and December of 2011, indicated the sump water was consistent with condensate or recirculation water, not what would be expected from condensed steam or water from the reactor vessel. Operations identified a leak from the 2B recirculation pump flange during the Mode 3 walkdown that was the source of the increased unidentified leakage. This flange leak explains the trends observed for the Unit 2 drywell unidentified leakage and the trends for the Unit 2 drywell containment atmosphere. The leak of the recirculation pump flange in itself is not a violation of NRC requirements or reportable under NRC regulations because no TS were violated and the flange is a mechanical joint under ASME Code Section XI. Currently Unit 2 has been online since April 20, 2012, and as of June 1, 2012 unidentified leakage on Unit 2 is 0.06 gpm.

Technical Specification Section 3.4.4 does not allow pressure boundary leakage of any quantity during Modes 1, 2 or 3. This pressure boundary leak was discovered in Mode 4 when the TS did not apply. A review of chemistry logs, operating logs, and engineering troubleshooting documentation for the unidentified leakage, resulted in no indications that this nozzle leak existed during the operating cycle. Therefore, the inspectors concluded that this issue did not violate NRC regulations. Documents reviewed as part of this inspection are listed in the Attachment to this report. This LER is closed.

This event followup review constituted one sample as defined in IP 71153-05.

.4 <u>(Closed) LER 05000265/2012-003-00: Unit 2 Automatic Reactor Scram Due to Digital Electro-hydraulic Control System Failure</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the plant and operator response to an automatic trip of Unit 2 on April 18, 2012, due to a valid, high reactor pressure signal. Unit 2 was at 23 percent power after a refueling outage and post modification testing was in progress on the main generator automatic voltage regulator. When the generator output breakers were opened per the test procedure, the digital electro-hydraulic control (DEHC) system did not respond to control reactor pressure as the operators expected. The operator at the controls recognized reactor pressure was increasing and attempted to manually scram the reactor, but the automatic scram occurred first. The resident staff responded to the control room immediately to monitor operator actions and observe the plant response to the scram. As reactor pressure lowered, the main turbine bypass valves closed as expected. Operators took action to control cooldown rate and stabilize plant parameters in accordance with plant procedures and TS.

Documents reviewed in this inspection are listed in the Attachment to this report. This LER is closed.

This event followup review constituted one sample as defined in IP 71153-05.

b. <u>Findings</u>

(1) <u>Failure to Identify Design Deficiency in Vendor Product</u>

<u>Introduction</u>: A Green finding of very low safety significance was self revealed on April 18, 2012, when this transient occurred. Inspectors identified the failure to review the vendor design documentation as a performance deficiency during the implementation of the DEHC modification with the rigor required by CC-AA-103-1003, “Owner’s Acceptance Review of External Engineering Technical Products.” Specifically, reviewers failed to identify elimination of a time delay that changed how the system responded to a load reject with no turbine trip. This finding resulted in the facility exceeding the allowed out of service time for TS 3.7.7, “Main Turbine Bypass System,”

on eleven occasions between the two units since the modification was installed with the most recent occurring on October 15, 2010, when Unit 2 reduced power to 30 percent to support single loop operation for 20 hours, exceeding the 6 hour allowed out of service time for inoperable main turbine bypass valves.

Description: On April 18, 2012, Unit 2 was at 23 percent power and holding after a refueling outage with post modification testing in progress on the main generator automatic voltage regulator. The test called for the generator output breakers to be opened manually, simulating a load reject. No turbine trip was expected to be generated on the load reject at this power level, and the staff expected the DEHC system to respond by controlling turbine speed and bypass valve position to mitigate the anticipated increasing reactor pressure transient. When the generator output breakers were opened, the DEHC control logic for the turbine shifted to speed control. The immediate increase in turbine speed created the expected mismatch condition between combined intercept valve (CIV) demand and valve position resulting in actuation of the CIV fast acting solenoid (FAS) and the FAS dump valves opening to "fast" close the CIVs. With the CIVs closed, no steam flow through the turbine resulted in a steam pressure increase and DEHC reacted as designed to open bypass valves to control steam pressure. Initially, bypass valves #1 through #4 opened fully and valve #5 opened to 50 percent in response to the DEHC signal to control pressure.

When the CIVs closed, the DEHC system logic immediately sent a signal to re-open the CIVs since 1800 rotations per minute (RPM) was the selected speed, and a turbine trip signal was not present. The CIV Servo valves opened to port fluid to the valve actuators and open the valves before the FAS dump valves reseated. By design, the dump valves could only reseat when there was little or no flow past the disk dump. The open servo created a flow path within the actuator that allowed a significant amount of EHC fluid to pass through the dump valves. This flow was high enough to cause system fluid pressure to lower significantly and internal pressure within the CIVs was not high enough to open the valves. In addition, header pressure at the main turbine control valves (TCVs) dropped to 725 psig (low enough so that the valves would not respond, but above the pressure setpoint that would generate a reactor scram signal.)

Fourteen seconds after the output breakers were open, turbine speed lowered below 1800 RPM due to the lack of steam flow. With turbine speed set to control at 1800 RPM and no turbine trip signal present, the DEHC sent a demand signal to reopen the main turbine control valves (TCV) and the CIVs to raise turbine speed. Acting as designed on the demand signal instead of actual valve position, DEHC logic assumed that the TCV and CIVs responded to the demand signal. The logic then sent a corresponding close signal to the bypass valves to keep the total signal within the set limits. Bypass valve #5 closed and #4 closed halfway. As the bypass valves closed with no other flow path for steam, reactor pressure increased until it reached the automatic scram set point and resulted in a scram. As reactor pressure lowered after the reactor scram, the main turbine tripped and the TCVs and CIVs closed. Digital electro-hydraulic control then responded as expected and the turbine bypass valves closed as reactor pressure lowered to the pressure setpoint as expected.

The DEHC modification was installed on Unit 1 in May 2007 during Refueling Outage Q1R19 and on Unit 2 in March 2008 during Q2R19. The DEHC vendor design had already been installed and tested at another boiling water reactor within the Exelon fleet prior to the first installation at Quad Cities. After this event, the licensee identified that critical differences in the hydraulic system designs between plants were not recognized during the design and review process. Specifically, the combined intercept valves (CIVs) at Quad Cities did not have solenoid operated shutoff valves to isolate flow for the FAS dump valves and instead relied on a short time delay between closing the FAS dump valves and opening the CIVs to allow oil to stop flowing through the dump valve and allow the dump valve to seat. This time delay was removed as part of the DEHC modification package provided by the vendor and the licensee's review failed to identify this design deficiency and how operation would be affected at Quad Cities Nuclear Power Station.

This vulnerability rendered the main turbine bypass valves inoperable unless the turbine was tripped. Technical Specifications 3.7.7, "Main Turbine Bypass System," required the main turbine bypass valves to be operable above 25 percent power or operating limits be placed on the minimum critical power ratio thermal limit per TS 3.2.2, "Minimum Critical Power Ratio (MCPR)." At 38 percent thermal power, the power load unbalance (PLU) is enabled. If sufficient load mismatch existed between the generator and the turbine, the PLU would trip the turbine. The licensee's transient analysis for the computation of the limits in the core operating limits report credits the PLU at 50 percent rated thermal power. With this design deficiency in the DEHC system, the licensee determined the bypass valves were inoperable above 25 percent and below 50 percent rated thermal power. The licensee put corrective actions in place to ensure the operating thermal limits would be reduced as required by TS 3.2.2 when the unit is operating in that power range.

Analysis: The inspectors concluded the failure to appropriately review the vendor design documentation was a performance deficiency and a finding. The finding was compared to the insignificant procedural error and administrative limit examples provided in Appendix E of IMC 0612 and determined to be sufficiently dissimilar from those examples due to exceeding TS action time limits. The performance deficiency was more than minor because the performance deficiency adversely affected the Reactor Safety - Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions. In this circumstance, the Design Control attribute of the cornerstone was adversely impacted when unintended consequences were introduced during the modification.

The limiting condition for operations (LCOs) discussed in this event report and the associated operating limitations were intended to ensure that thermal limits for the fuel are not violated during postulated operating transients. The transient event discussed in this LER transient occurred at a power where the thermal limits were not challenged and no actual thermal limit violations were identified during the inspector's review of operations during the periods that the issue existed. However, the vulnerability existed in both units since the modification was installed. Using IMC 0609, Attachment 4, Table 4a, Initiating Events Cornerstone - Transient Initiators, inspectors determined that the performance deficiency did not contribute to the likelihood of both a reactor trip and unavailability of mitigation equipment since the credited pressure mitigation equipment was the main steam safety and relief valves which are unaffected by the event. Therefore, this finding screens as Green, or very low safety significance. The inspectors did not identify a cross-cutting aspect for this performance deficiency since the performance deficiency occurred during the DEHC modification review in 2006 and was therefore considered a legacy issue.

Enforcement: Limiting Condition for Operability 3.7.7, “Main Turbine Bypass System,” states that the main turbine bypass system shall be operable above or equal to 25 percent power or the LCO 3.2.2, “Minimum Critical Power Ratio (MCPR)” limits for an inoperable main turbine bypass system, as specified in the core operating limits report, are made applicable.

Technical Specification actions to implement the limits or reduce power to less than 25 percent are required to be completed within 6 hours of bypass valves being out of service.

Contrary to the above, the licensee operated both units for periods exceeding the action time allowed by TS on multiple occasions since implementing the DEHC modification. During the most recent occurrence, Unit 1 operated at 30 percent power for more than 20 hours on October 15, 2010, and did not implement the operating limit restrictions required by LCO 3.2.2 when the bypass valves were inoperable due to the DEHC modification to the electro-hydraulic control system. The inspectors’ review of plant operating records since the modifications were installed identified seven other periods for Unit 1 and three other periods for Unit 2 when the plants were operated for more than 6 hours continuously between 25 and 50 percent power. Because this violation was of very low safety significance and it was entered into the licensee’s corrective action program as IR 1355763, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000254/2012003-03, 05000265/2012003-03; “Failure to Identify Design Deficiency in Vendor Product”).** The licensee’s immediate corrective actions for plant stability were discussed in previous sections. Operating instructions were put in place to alert the operators to the vulnerability and to ensure the operating limits were in place as required by TSs when power was between 25 and 50 percent power.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 10, 2012, the inspectors presented the inspection results to Site Vice President, T. Hanley, 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.

4OA7 Licensee-Identified Violations

The following violation of very low 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 dispositioned as an NCV.

- The licensee identified a finding of very low safety significance and associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, Test Control, for unacceptable preconditioning of high pressure coolant injection (HPCI) valves due to performing a safety-related PM prior to prior the quarterly in-service testing of the same valves. A maintenance delay, which caused a shift in the scheduled performance of the quarterly testing of the HPCI system air operated valves, produced a schedule conflict that resulted in cycling of the 1-2301-28, 1-2301-29, and 1-2301-64 valves less than 9 hours prior to scheduled quarterly in- service testing of the same valves. The licensee entered the issue into their corrective action program as IR 1364184. The performance deficiency was determined to be more than minor because, if left uncorrected, it could lead to a more significant safety concern. Preconditioning systems, structures or components prior to performing required TS surveillance activities could mask adverse conditions and affect operability. The licensee re-performed the surveillance with no issues after an acceptable time had elapsed. The finding was of very low safety significance because it was not a design/qualification deficiency, did not represent a loss of system safety function, did not result in a loss of function of a single train for greater than its TS-allowable outage time, did not result in a loss of function of non safety-related risk-significant equipment, and was not risk-significant due to external events.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Hanley, Site Vice President
W. Beck, Regulatory Assurance Manager
D. Collins, Radiation Protection Manager
J. Garrity, Maintenance Director
A. Misak, Nuclear Oversight Manager
V. Neels, Chemistry/Environ/Radwaste Manager
K. Ohr, Site Engineering Director
T. Scott, Work Management Director
R. Sieprawski, Training Support Manager

Nuclear Regulatory Commission

M. Ring, Chief, Reactor Projects Branch 1
R. Elliott, Reactor Engineer, Reactor Projects Branch 1

Illinois Emergency Management Agency (IEMA)

C. Settles, IEMA

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000254/2012003-01; 05000265/2012003-01	NCV	Bus Energized With Grounding Device Installed (Section 1R20.1)
05000254/2012003-02	NCV	Procedure Noncompliance Impacting Reliability of HPCI (Section 1R20.2)
05000254/2012003-03; 05000265/2012003-03	NCV	Failure to Identify Design Deficiency in Vendor Product (Section 4OA3.4)

Closed

05000254/2012003-01; 05000265/2012003-01	NCV	Bus Energized With Grounding Device Installed (Section 1R20.1)
05000254/2012003-02	NCV	Procedure Noncompliance Impacting Reliability of HPCI (Section 1R20.2)
05000254/2012003-03; 05000265/2012003-03	NCV	Failure to Identify Design Deficiency in Vendor Product (Section 4OA3.4)
05000254/2012-001-00	LER	Control Room Emergency Ventilation Air Conditioning System Inoperable (Section 4OA3.1)
05000254/2012-002-00	LER	Standby Gas Treatment System Loss of Safety Function Due to Loss of Emergency Power (Section 4OA3.2)

05000265/2012-002-00	LER	Unit 2 Reactor Pressure Vessel Instrument Nozzle Leak (Section 4OA3.3)
05000265/2012-003-00	LER	Unit 2 Automatic Reactor Scram Due to Digital Electro-hydraulic Control System Failure (Section 4OA3.4)

Discussed

None.

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.

Section 1R01

- WC-AA-107; Seasonal Readiness; Revision 10
- QCOA 6000-03; Low Switchyard Voltage; Revision 14
- QCOA 0010-10; Tornado Watch-Warning, Severe Thunderstorm Warning or Severe Winds; Revision 23
- OP-AA-108-111-1001; Severe Weather and Natural Disaster Guidelines; Revision 07
- QCOA 0010-06; Key Phone Numbers and Checklists for Referenced 10 Block Procedures; Revision 15
- QCOA 6100-03; Loss of Offsite Power; Revision 30
- Letter from Tim Hanley, Site VP Quad Cities to Bryan Hanson, Senior VP Mid-West Nuclear Operations; Subject: Quad Cities Station Certification of 2012 Summer Readiness, May 14, 2012
- WO# 1508233; Rebuild Control Rod Drive Spare Rotating Element
- IR 1252191; LEFM System Condition Reports Evaluation and Analysis
- IR 1269691; 2012 Quad Cities Summer Readiness Action

Section 1R04

- QCOP 6600-01; Diesel Generator 1(2) Preparation for Standby Operation
- QCOP 6600-12; Diesel Generator Air Start System Pressure Verification
- QOM 1-3700-01; U1 RBCCW Valve Checklist (Outside Drywell); Revision 10
- QCOS-2900-06; SSMP Valve Position Verification; Revision 12
- QCOP-2900-01; Safe Shutdown Makeup Pump System Preparation for Standby Operation; Revision 33
- QCOP 1300-01; RCIC System Preparation for Standby Operation; Revision 40
- QCOP 1300-09; RCIC Local Manual Operation (H.7.a); Revision 24
- QCOP 1300-02; RCIC System Manual Startup (Injection/Pressure Control); Revision 30
- Drawing M-70; Diagram of Safe Shutdown Make-up Pump System; Revision Z
- Drawing M-50; Diagram of Reactor Core Isolation Cooling RCIC Piping; Revision BQ
- AR 1224891; Minor Air found in SSMP Discharge Piping during Fill/Vent
- AR 1337496; SSMP Recirc Valve VPI [Valve Position Indication] not Accurate
- AR 1299919; SSMP Flow controller (MCR) Standby Setpoint – Procedure Rev. Required
- Safe Shutdown Service Water Strainer High D/P [Differential Pressure] Cleaned

Section 1R05

- Pre-Fire Plan: FZ 1.1.2.1; Unit 2 RB 544’-0” Elev. Torus Area and Top of Torus
- Pre-Fire Plan: FZ 1.1.1.4; U1 RB 647' Elevation 3rd Floor
- Pre-Fire Plan: FZ 1.1.1.3; U1 RB 623' Elevation Mezz Level
- Pre-Fire Plan: FZ 7.2; U2 TB Elevation 628’-6”, 250V Battery Room
- Pre-Fire Plan: FZ 6.2.A; U2 TB Elevation 615’-6”, “A” Battery Charger Room U-2
- Pre-Fire Plan: FZ 6.2.B; U2 TB Elevation 615’-6”, “B” Battery Charger Room U-2

- Pre-Fire Plan: Fire Zone 6.2.A; Unit 2 Turbine Building, Elevation 615'-6", "A" Battery Charger Room U-2;
- Pre-Fire Plan: Fire Zone 6.2.B; Unit 2 Turbine Building, Elevation 615'-6", "B" Battery Charger Room U-2;
- Pre-Fire Plan: Fire Zone 7.2; Unit 2 Turbine Building, Elevation 628'-6", 250V Battery Room;
- OP-AA-201-008; Pre-Fire Plan Manual; Revision 3
- National Fire Protection Association (NFPA) 804; Standard for Fire Protection for Advanced Light Water Reactor Electric Generating Plants
- NFPA 1620; Standard for Pre-Incident Planning

Section 1R11

- June 11, 2012 LORT Scenario for as-found evaluation and listing of critical tasks

Section 1R12

- Enterprise Maintenance Rule Production Database for the following systems:

  - Z0200; Nuclear Boiler
  - Z0203; Main Steam Valves

- TS 3.6.1.3, Primary Containment Isolation Valves and applicable Bases
- UFSAR, Section 15.6.4, Steam Line Break Outside Containment
- UFSAR, Section 15.6.5, Loss-of-Coolant Accidents Resulting from Piping Breaks Inside Containment
- IR 1342937, "B" Main Steam Line Exceeded Tech. Spec. Limit of <35 SCFH, Four Total MSIV Failures
- IR 1342931, "2D MSIV LKG [leakage] Exceeded Admin Limit of <34 SCFH"
- IR 1342935, "2B MSIV LKG [leakage] Exceeded Admin Limit of <34 SCFH"
- IR 1342938, "1A MSIV LKG [leakage] Exceeded Admin Limit of <34 SCFH"

Section 1R13

- Q2R21 Week 3 Shutdown Safety Profile
- Q2R21 Various Work Group Work Activities
- Unit 1 Protected Equipment Week of April 23
- Work Week Safety Profile 12-18-06
- Work Week Safety Profile 12-19-7
- ER-AA-600; Risk Management; Revision 6
- ER-AA-600-1042; On-Line Risk Management; Revision 7
- WC-AA-104; Integrated Risk Management; Revision 18
- IR 1367374; U1 HPCI Flange 2-Foot Steam Plume at 1-2339-10"-B
- WR 402272; U1 HPCI Flange 2-Foot Steam Plume at 1-2339-10"-B
- Drawing M-46 Sheet 1; Diagram of High Pressure Coolant Injection – HPCI Piping; Revision C8
- Drawing M-46 Sheet 2; Diagram of High Pressure Coolant Injection HPCI Piping; Revision R

Section 1R15

- IR 1349496; U2 DG CWP Breaker Thermals Found Tripped; 04/03/12
- IR 1352338; Update to IR 1349496 For Cause of Thermal Overload Trip; 04/10/12
- WO #1337079; MCC 29-2 CUB E5 DG Cooling WTR PMP Cooler Fan A Normal Feed

- IR 1351413; MCC 28/29-5 Swapped to Bus 28 During QCOS 6600-48; 04/08/12
- EC 388804; Turbine Bypass Valves Operability at Low Reactor Power Levels
- ECR 404868; Document Conclusions Reached From Initial Analysis of Cause for Unit 2 Scram During Generator AVR Testing
- IR 1356562; U1 Evaluation of Bypass Valve System Operability; 04/20/2012
- IR 1172248; 2C RHRSW Pump Did Not Start Promptly
- IR 1187270; Delay in Pump Run Indication At Start
- IR 1187534; 2C RHRSW Rework Identified
- IR 1365523; Dresden IR 1364609 Merlin Gerin BKR Failure Analysis Report
- EC 389153; Review Degraded Grease in Merlin Gerin Circuit Breakers
- WO 1417677; Troubleshoot 2C RHRSW Pump Did Not Start Promptly
- IR 1366596; Level Switch Failed to Reset
- IR 1366647; Pipe for 1-2304-8203 HPCI Lim. Switch is Clogged with Sludge
- IR 1377859,DPIS 1-0261-34A Sticky At Around 2.5 psig
- IR 1341069; DPIS 1-261-34A Decreasing Indication Sticky
- WO 1524339; Troubleshoot DPIS 1-261-34A
- ECR 405602; Power Labs Report QDC-08270 Identified Phenolic Material Used for Barton 288A Actuator Assembly
- ECR 405600; EQ Approval and Material Verification Testing fot Barton 288A to Replace a Barton 288 in the DPIS 1(2)-0261-34A/B/C/D Applications

Section 1R18

- EC 388685; Relocate U2 EDG ISOC Contact to Fast Start Relay
- WO 1531012; Relocate U2 EDG ISOC Contact to Fast Start Relay EC 388685
- Electrical Drawing 4E-2336, Revision AF; relay Metering and Excitation Diagram Standby Diesel Generator
- Electrical Drawing 4E-2350A, Sheet 1, Revision AS and 4E-2350A, Sheet 2, Revision AP; Schematic Diagram Engine Control and Generator Excitation Standby Diesel – Generator 2
- QCOS 6600-48, Unit Two Division II Emergency Core Cooling System Simulated Automatic Actuation and Diesel Generators Auto –Start Surveillance
- EC 388628; Half Nozzle Repair for N11B

Section 1R19

- WO 01528266, “ECCS and EDG Auto Start Test Aborted”
- QOS 6500-04; 4KV Bus 23-1 Under-Voltage Functional Test; Revision 38
- QCOS 0201-08; Reactor Vessel Class 1 and Associated Class 2 System Leak Test; Revision 52
- QCTS 0600-11; HPCI Steam Supply Local Leak Rate Test (MO-1(2)-2301-4, MO-1(2)-2301-5)
- QCOS 6600-48; Unit Two Division II Emergency Core Cooling System Simulated Auto Activation and Diesel Generator Auto-Start Surveillance; Revision 25
- QCOS 2300-07; HPCI System Turbine Overspeed Test, Revision 29
- WO #758779; HPCI System Turbine Overspeed Test

Section 1R20

- IR 1358645; NRC Identified Structural Equipment Left Attached to Bus
- Work Order 880895; HPCI Turbine Dismantle
- IR 1358458; Incorrect Use of MA-QC-716-026-1001 Procedure During Q2R21
- IR 1382498; Additional Learnings From Seismic Housekeeping IR 1358458
- ECR 404530; Review of Seismic Housekeeping in Unit 1 HPCI Room

- MA-QC-716-026-1001; Seismic Housekeeping
- EC 335248; Request Engineering Approval of the Floor Landing Plan to Set HPCI Turbine Casing onto During Q2R16
- EC 388628; Half Nozzle Repair for N11B
- EC 388684; Lost Part Evaluation – Material From Repair of Nozzle N11B
- IR 1354062; Documentation of NRC Verbal Approval of Relief Request 14R-19

Section 1R22

- QCOS 1600-07; Reactor Coolant Leakage in the Drywell (RCS)
- QCOS 0250-04; MSIV Closure Timing; Revision 23
- QCOS 1300-01; Periodic RCIC Pump Operability Test; Revision 37
- QCOS 1300-05; Quarterly RCIC Pump Operability Test; Revision 51
- QCOS 1300-07; RCIC Manual Initiation Test; Revision 33
- QCOS 2300-01; Periodic HPCI Pump Operability Test, Revision 52
- QCOS 2300-05; Quarterly HPCI Pump Operability Test; Revision 68
- QCOS 2300-27; HPCI Pump Comprehensive/Performance Test; Revision 28

Section 1EP6

- EP Drill Scenario, Team 'D', May 10, 2012
- EP Drill Scenario, Team 'A', June 14, 2012

Section 4OA1

- NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 6
- LS-AA-2100; Monthly Data Elements for NRC Reactor Coolant System (RCS) Leakage; Revision 6

Section 4AO2

- IR 1348778; QCOS 6600-48, ECCS and EDG Auto Start Test Aborted
- WO 1528286, QCOS 6600-48, ECCS and EDG Auto Start Test Aborted
- Drawing 4E-2336; Relay Metering and Excitation Diagram Standby Diesel Generator 2
- Drawing 4E-2350A, Sheet 1; Schematic Diagram Engine Control and Generator Excitation Standby Diesel – Generator 2
- Drawing 4E-2350A, Sheet 2; Schematic Diagram Engine Control and Generator Excitation Standby Diesel – Generator 2
- IR 1348670; Bus 24 Undervoltage During Setup for QCOS 6600-39
- IR 1317922; U2 EDG Voltage Exceeded 5000V During Load Reject
- IR 1357990; U-2 15-minute Average Power Limit Exceeded
- IR 1350193; Leak Path Developed Through N-11B Instrument Nozzle Due to IGSCC
- EN 47806; Degraded Condition Due To Identified Reactor Pressure Vessel Test Leakage

Section 4AO3

- IR 1355763; U-2 Reactor Scram during AVR [Automatic Voltage Regulator] Load Reject Test
- EN 47847; Unit Two Automatic Reactor Scram on High Reactor Pressure
- ECR 404868; Document Conclusions Reached From Initial Analysis of Cause For Unit 2 Scram During Generator AVR Testing
- EC 388804; Turbine bypass Valve Operability Evaluation
- IR 1350193; Leak Path Developed Through N-11B Instrument Nozzle Due to IGSCC

- EC 388628; Half Nozzle Repair for N11B
- EC 388684; Lost Part Evaluation – Material From Repair of Nozzle N11B
- IR 1354062; Documentation of NRC Verbal Approval of Relief Request 14R-19
- EN 47806; Degraded Condition Due To Identified Reactor Pressure Vessel Test Leakage
- Chemistry drywell sump sampling logs from October 2011 to March 2012
- Chemistry trending analysis for Unit 1 and Unit 2 Drywell Sump Inleakage versus CAM particulate isotopic activity
- QCTS 2000-01; Drywell Leakage Troubleshooting; Revision 1
- IR 1345302; 345KV Disconnect Closed in to Ground
- IR 1345407; GCB 9-10 Bus 10 Disconnect Extent of Condition Walkdown
- IR 1345602; 4.0 Critique for Operations Response to GCB 9-10 Event
- IR 1345341; Security implements Comp Measures
- OP-AA-109-101; Clearance and Tagging
- OP-AA-108-107-1002; Interface Procedure Between ComEd/PECO and Exelon Generation (Nuclear/Power) for Transmission Operations
- Regulatory Issue Summary 2004-05, Grid Reliability and the Impact on Plant Risk and the Operability of Offsite Power
- EN 47875; Invalid Protection System Actuation During Station Electrical Transient
- Clearance Order 95504, Transformer 22
- IR 1355763; U-2 RX Scram During AVR Load Reject Test;
- Root Cause Report for IR 1355763
- IR 1322407; 'B' Control Room HVAC RCU Breaker Found Tripped
- IR 1351277; B CR HVAC RCU LLSV Leakage Degrading
- IR 1324391; B CR HVAC RCU Liquid Line SOV Leaking By
- EN 47634; Control Room Emergency Ventilation Air Conditioning System Inoperable
- EC 387643; Refrigeration Condensing Unit (RCU) 0-9400-102 (B CREV) Circuit Breaker at 1-7800-18-4-1D is Nuisance; 2/7/12
- NES-EIC-10.01: "Molded Case Circuit Breaker Selection and Setting Design Standard"; Revision 2
- EC 375422; Install Time Delay Relay on ½ B CREVs RCU 0-9400-102
- IR 1324022; Review Affect of Increased Starting Freq for B CR HVAC RCU
- IR 1349304; Hard 125VDC Ground on U1 DG Governor Oil Booster Pump
- PowerLabs QDC-977728 Failure Analysis of John S. Barnes ¾ HP motor, Part Number GC684
- IR 1351050; U1 EDG GVNR Oil BSTR PMP MTR Faulted Per PL RPT QDC977728
- IR 1351061; PWRLAB RPT QDC-97728 ID's Failure Mode Extent of Condition
- IR 1351071; PWRLAB RPT QDC-97728 ID's Failure Mode Extent of Condition

<u>Section 4AO7</u>

IR 1364184; Evaluate for Unacceptable Preconditioning in QCOS 2300-06
EC 387445; Quad Cities Discussion on Preconditioning

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CIV	Combined Intercept Valves
DEHC	Digital Electro-hydraulic Control
EC	Engineering Change
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
HPCI	High Pressure Coolant Injection
HVAC	Heating, Ventilation, and Air Conditioning
IP	Inspection Procedure
IPEEE	Individual Plant Examination of External Events
IR	Issue Report
LCO	Limiting Condition for Operation
LER	Licensee Event Report
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PI	Performance Indicator
PLU	Power Load Unbalance
PRA	Probabilistic Risk Assessment
RCU	Refrigeration Condensing Unit
RFO	Refueling Outage
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPM	Rotations Per Minute
SBGTS	Standby Gas Treatment System
SDP	Significance Determination Process
SSMP	Safe Shutdown Makeup Pump
TCV	Turbine Control Valve
TS	Technical Specifications
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
WO	Work Order

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Sincerely,

/RA/

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

Docket Nos. 50-254 and 50-265
License Nos. DPR-29 and DPR-30

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Letter to M. Pacilio from M. Ring dated August 2, 2012

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000254/2012003 AND 05000265/2012003

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