UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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August 12, 2014

Mr. Michael J. Pacilio
Senior VP, Exelon Generation Co., LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000254/2014003;
05000265/2014003

Dear Mr. Pacilio:

On June 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on July 9, 2014 with Mr. S. Darin, and other members of your staff.

Based on the results of this inspection, one NRC-identified and four self-revealed findings of very low safety significance were identified. Four of the findings involved a violation of NRC requirements. Further, the inspectors documented a licensee-identified violation which was determined to be of very low safety significance. Because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy.

If you contest the subject or severity of any NCV or finding, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532-4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Quad Cities Nuclear Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding 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 the Quad Cities Nuclear Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* 2.390, “Public Inspections, Exemptions, Requests for Withholding,” of the NRC's "Rules of Practice," a copy of this letter and 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 NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Christine Lipa, Chief
Branch 1
Division of Reactor Projects

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

Enclosure:
IR 05000254/2014003; 05000265/2014003
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:	05000254/2014003; 05000265/2014003
Licensee:	Exelon Generation Company, LLC
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, IL
Dates:	April 1 through June 30, 2014
Inspectors:	R. Murray, Senior Resident Inspector J. Boettcher, Acting Resident Inspector T. Bilik, Senior Reactor Engineer J. Bozga, Reactor Inspector R. Edwards, Reactor Inspector M. Mitchell, Health Physicist C. Phillips, Project Engineer S. Shah, Reactor Engineer J. Steffes, Resident Inspector, DAEC M. Ziolkowski, Reactor Engineer
Approved by:	Christine Lipa, Chief Branch 1 Division of Reactor Projects

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SUMMARY OF FINDINGS

Inspection Report 05000254/2014003; 05000265/2014003; 04/01/2014 – 06/30/2014; Quad Cities Nuclear Power Station, Units 1 and 2; Outage Activities, Identification and Resolution of Problems, and Follow-Up of Events and Notices of Enforcement Discretion.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Four Green findings were self-revealed and one Green finding was identified by the inspectors. Four of the findings were considered non-cited violations (NCV) of NRC regulations. One licensee-identified violation is listed in Section 4OA7 of this report. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas" effective date January 1, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 5, dated February 2014.

NRC-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

Green. A finding of very low safety significance (Green) with an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was self-revealed for the licensee's failure to demonstrate compliance with ComEd Standard N-EM-0035 for safety-related cables within the Unit 2 'D' Heater Bay. Specifically, the licensee failed to route the Instrument Bus and Essential Service (ESS) Bus cables with minimum cable static bend radius requirements in a manner consistent with N-EM-0035. This resulted in an event that caused a fire in the turbine building, smoke in various motor control center (MCC) cubicles due to overheated control power transformers (CPTs) (including one safety-related MCC), a manual scram and main steam isolation, and an Alert emergency declaration. The licensee's corrective actions for this event included repairing cables damaged in the fire, replacement of the expansion joint; and revision to the steam seal operating procedures. The licensee documented this issue in the corrective action program (CAP) as Issue Report (IR) 1642409.

The finding was determined to be more than minor per IMC 0612, Appendix B, "Issue Screening," because it was a precursor to a significant event. Specifically, failure to install Instrument bus and ESS cables in accordance with the requirements of N-EM-0035 resulted in the initiation of an electrical fault and cable fire. The fire resulted in a manual reactor scram and the loss of safety-related equipment. The performance deficiency was associated with the Reactor Safety - Initiating Events Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the capability of equipment relying on the power supply form Instrument and ESS Buses, both during shutdown as well as power operations. A detailed risk evaluation was performed by the regional senior reactor analysts (SRAs), and the finding was determined to be of very low safety significance. The finding does not have a cross-cutting aspect, because it is associated with a performance deficiency from the timeframe of the plant's original construction and is not representative of the licensee's current performance. (Section 4OA3)

Green. A finding of very low safety significance (Green) and associated non-cited violation of Technical Specification (TS) Section 5.4.1 was self-revealed on April 2, 2014 for the licensee's failure to establish a procedure in accordance with the requirements of Regulatory Guide 1.33. Specifically, the licensee established procedure QOP 5600-01, "Gland Seal System Operation," for use during startup of the Main Steam and Turbine-Generator systems. However, the procedure failed to include provisions to ensure that the steam seal regulator bypass valve, 2-3099-S2 (S2) was closed prior to lifting the steam seal bypass relief valve and exceeding the bypass line design pressure. That resulted in a failure of the piping and a significant steam leak in the 'D' heater bay. Immediate corrective actions taken by the licensee included revising their procedures for operation of the Gland Seal system and conducting just-in-time training on Gland Seal system operation for operators prior to the subsequent startup on Unit 2. In addition, the licensee planned to review and revise their operator training program for the Gland Seal system. The licensee documented this issue in CAP as IR 1642409.

The performance deficiency was determined to be more than minor and a finding because it was a precursor to a significant event. Specifically, the Gland Seal System steam seal regulator bypass valve was opened at pressures that the bypass line was not designed to withstand. This led to a significant steam leak in the 'D' heater bay, and the resulting fire caused by a degraded cable fault. The inspectors concluded this finding was associated with the Initiating Events Cornerstone and a Detailed Risk Evaluation was required. The finding was determined to be of very low risk significance by the SRAs. The inspectors determined that a principal contributor to the finding was that the licensee did not stop when faced with uncertain conditions and risks were not evaluated and managed before proceeding. Specifically, when the licensee identified a steam packing leak in the S1 valve in June 2013 and decided to close the valve when leakage increased to an unacceptable level in October 2013, they failed to recognize the risk and prioritize the repair of the valve prior to the reactor startup on April 2, 2014. In addition, when operators faced unexpected system response during the startup of the Gland Seal system and conflicting procedural guidance, the cause of the problem was not thoroughly understood and evaluated prior to continuing the system startup. As a result, the inspectors assigned a cross-cutting aspect of challenging the unknown in the area of human performance (H.11). (Section 4OA3)

Green. A finding of very low safety significance was self-revealed when the licensee failed to re-establish oil level in accordance with vendor requirements in the Unit 2 Main Power Transformer (MPT-2) Conservator Oil Preservation System (COPS) tank after repairs were performed on the MPT-2 cooler group #4 upper isolation valve. Specifically, on May 12, 2014, the MPT-2 pressure relief device (PRD) actuated because of a high oil level in conjunction with higher temperature at full power operations. This resulted in operators reducing Unit 2 power to approximately 79 percent rated thermal power to reseat the PRD after venting approximately 20 gallons of oil. The licensee drained approximately 200 gallons of oil from the COPS tank prior to resuming full power operations. The licensee documented this issue in CAP as IR 1659110.

The licensee's failure to follow vendor manual requirements for filling MPT-2 with oil was a performance deficiency. The performance deficiency was determined to be more than minor, and a finding because it was associated with the Initiating Events Cornerstone

Attribute of Procedure Quality and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability. The finding was determined to be of very low safety significance because each of the questions provided in IMC 0609, Appendix A, Exhibit 1 "Initiating Events Screening Questions" was answered "No". This finding has a cross-cutting aspect of field presence in the area of human performance for failing to ensure supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, oversight of vendor activities during re-fill of the COPS tank failed to ensure that vendor guidance was used (H.2). (Section 4OA3)

Cornerstone: Mitigating Systems

Green. A finding of very low safety significance and associated non-citied violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to meet the requirements of procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," when scaffold Q0178 was built with one of its supports in rigid contact with the operable Unit 2 torus. Immediate corrective actions included modifying the scaffold such that it was no longer in contact with the Unit 2 torus. This issue was captured in the licensee's CAP as IR 1639356.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of protection against external factors and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a scaffold built in contact with safety related equipment could damage the equipment and affect its availability and reliability. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors answered, "No," to all of the Exhibit 2, "Mitigating Systems Screening Questions," in section A and determined the finding was of very low safety significance. This finding has a cross-cutting aspect of documentation in the area of human performance because the licensee did not create and maintain complete, accurate and, up-to-date documentation. Specifically, the licensee did not completely and accurately evaluate the acceptability of a scaffold that was in contact with safety related equipment (H.7). (Section 1R20)

Green. A finding of very low safety significance and associated non-citied violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the licensee's failure to meet the requirements of MA-AA-716-012, "Post Maintenance Testing," which states, in part that post maintenance testing ensures that a component is able to perform its intended function and that the original deficiency is corrected. Specifically, licensee procedure QCEMS 0210-01 failed to include quantitative and qualitative acceptance criteria for determining that the Unit 1 250 VDC Battery Charger could perform its intended function. This issue was placed into the licensee's CAP as IR 1631541. Immediate corrective actions included replacing the float potentiometer in the battery charger circuitry, replacing a thyristor in the voltage regulation circuitry, and correcting a loose solder connection identified in the battery charger circuitry. Planned corrective actions include revising procedure QCEMS 0210-01 to include acceptance criteria that ensure the battery chargers can satisfactorily perform their intended function.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors answered, "No," to all of the Exhibit 2, "Mitigating Systems Screening Questions," in Section A and determined the finding was of very low safety significance. This finding had a cross-cutting aspect of design margins in the area of Human Performance because the licensee did not operate and maintain the battery charger within design margins. Specifically, the licensee's post maintenance testing acceptance criteria did not give them enough margin to prevent the battery from becoming inoperable (H.6). (Section 4OA2)

Licensee-Identified Violations

Cornerstone: Occupational Radiation Safety

One violation of very low safety significance (Green) that was identified by the licensee has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's Corrective Action Program. The violation and corrective action tracking number are discussed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1

Unit 1 operated at 100 percent thermal power from April 1, 2014 through April 8, 2014. On April 8, 2014, operators reduced power to 84 percent rated thermal power to replace a leaking seal cooling hose on the 1B Reactor Feed Pump. The unit reached full power on April 9, 2014.

On April 12, 2014, operators reduced power to 84 percent to facilitate repairs on the 1B Reactor Feed Pump suction relief valve discharge piping. The unit was returned to full power the same day and remained at full power throughout the evaluated period 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 period in Mode 3 after commencing an unplanned shutdown on March 31, 2014, to comply with TS Limiting Condition for Operation 3.4.4, "Reactor Coolant System Operational Leakage." During routine inspections of control rod drive hydraulic control unit (HCU) valves, the licensee identified a through body leak on HCU 18-27 insert isolation valve 2-0305-101. Leakage from this valve is considered pressure boundary leakage because it is unisolable from the reactor coolant system.

Unit 2 began its startup from Q2F66 on April 1, 2014. However, due to a fire in the heater bay (see Section 4OA3), the operators inserted a manual scram on April 2. The unit remained shut down until refueling outage Q2R22 was entered on April 5, 2014. The unit restarted on May 6 and reached full power on May 8, 2014. Unit 2 operated at 100 percent thermal power until May 12, 2014, when operators conducted an emergency power reduction to approximately 79 percent thermal power due to indications of the MPT-2 main oil tank pressure relief device lifting. Following maintenance on the transformer, the unit again reached 100 percent thermal power on May 13, 2014. Unit 2 operated at 100 percent thermal power throughout the remainder of the evaluated period ending June 30, 2014, 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, Barrier Integrity and Emergency Preparedness

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:

- coordination between the TSO and the plant during off-normal or emergency events;
- explanations for the events;
- estimates of when the offsite power system would be returned to a normal state; and
- 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:

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

Documents reviewed are listed in the Attachment to this report. The inspectors also reviewed 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.

.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. Documents reviewed 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 their corrective action program in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- diesel generator cooling water; and
- fuel pool cooling and filtering.

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

b. Findings

No findings were identified.

.3 Readiness for Impending Adverse Weather Condition – Severe Thunderstorm Watch and Hot Weather Alert

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility, along with high ambient outside temperatures during the week of June 16, 2014, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On June 18, 2014, the inspectors walked down the Turbine Building general area, in addition to the licensee's emergency AC power systems, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant-specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado event. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the UFSAR and performance requirements for systems selected for inspection, and daily monitoring of the off-normal environmental conditions. The inspectors also reviewed a sample of CAP items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Documents reviewed are listed in the Attachment to this report.

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

b. 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:

- Shutdown Cooling Loop “A” During Refueling Outage Q2R22;
- Unit 2 Direct Current Power Systems;
- Unit 1/2 Emergency Diesel Generator During Unit 2 Emergency Diesel Generator Inoperability; and
- Unit 2 Station Blackout Diesel Generator.

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, 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.

.2 Semi-Annual Complete System Walkdown

a. Inspection Scope

From June 25 to June 30, 2014, the inspectors performed a complete system alignment inspection of the Unit 1 Core Spray System to verify the functional capability of the system. This system was selected because it was considered both safety significant and risk significant in the licensee’s probabilistic risk assessment. The inspectors walked down the system to review mechanical and electrical equipment lineups; electrical power availability; system pressure and temperature indications, as appropriate; component labeling; component lubrication; component and equipment cooling; hangers and supports; operability of support systems; and to ensure that ancillary equipment or debris did not interfere with equipment operation. A review of a sample of past and outstanding WOs was performed to determine whether any deficiencies significantly affected the system function. In addition, the inspectors reviewed the CAP database to ensure that system equipment alignment problems were being identified and appropriately resolved. Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

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

- Fire Zone 8.2.6.C, Unit 1/2 Turbine Building, Elevation 595'-0", Electro-hydraulic Control Fluid Reservoir;
- Fire Zone 8.2.7.D, Unit 2 Turbine Building, Elevation 615'-6", LP Heater Bay (East)/D Heater Bay;
- Fire Zone 8.2.7.E, Unit 2 Turbine Building, Elevation 615'-6", North Mezzanine Floor; and
- Fire Zone 9.3; Unit 1/2 Reactor Building, Elevation 595'-0", 1/2 Diesel Generator.

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

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

b. Findings

No findings were identified.

.2 Annual Fire Protection Drill Observation (71111.05A)

a. Inspection Scope

On May 21 and May 29, 2014, the inspectors observed fire brigade activations for a simulated fire on the Unit 1 Electro-Hydraulic Control Skid. Based on these observations, the inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that the licensee staff identified deficiencies, openly discussed them in a self-critical manner at the drill debrief, and took appropriate corrective actions. Specific attributes evaluated were:

- proper wearing of turnout gear and self-contained breathing apparatus;
- proper use and layout of fire hoses;
- employment of appropriate firefighting techniques;
- sufficient firefighting equipment brought to the scene;
- effectiveness of fire brigade leader communications, command, and control;
- search for victims and propagation of the fire into other plant areas;
- smoke removal operations;
- utilization of pre-planned strategies;
- adherence to the pre-planned drill scenario; and
- drill objectives.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. The specific documents reviewed are listed in the Attachment to this report. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the corrective action program to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area to assess the adequacy of watertight doors and verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 2 Torus Area

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

This inspection constituted one internal flooding sample as defined in IP 71111.06-05.

b. Findings

No findings were identified.

1R08 Inservice Inspection Activities (71111.08P)

From April 7 to April 11, 2014, the inspectors conducted a review of the implementation of the licensee's inservice inspection (ISI) program for monitoring degradation of the reactor coolant system, risk significant piping and components, and containment systems.

The inservice inspections described in Sections 1R08.1 and 1R08.5 below constituted one inspection sample as defined in IP 71111.08-05.

.0 Piping Systems In-Service Inspection

a. Inspection Scope

The inspectors either observed or reviewed the following non-destructive examinations mandated by the American Society of Mechanical Engineers (ASME) Section XI Code to evaluate compliance with the ASME Code Section XI and Section V requirements, and if any indications and defects were detected, to determine if these were dispositioned in accordance with the ASME Code or an NRC approved alternative requirement.

- Ultrasonic (UT) Examination of Elbow-to-Pipe Weld in the Residual Heat Removal (RHR) 'B' System, Weld 10BD-S7;
- UT of Elbow-to-Pipe Weld in the RHR 'B' System, Weld 10BD-S11;
- Dye Penetrant Examination of the Reactor Recirculation System Lug Welds, 0200-W-124A;
- Magnetic Particle (MT) Examination of RHR 'A' Saddle-Nozzle, Weld N6A-F1-RHRHX, Report No. Q2R22-MT-001;
- MT Examination of RHR 'A' saddle-nozzle, Weld N6A-F2 RHRHX, Report No. Q2R22-MT-002;
- Visual, VT-3, Examination Reactor Recirculation system component support 0200-W-124 A&B; and
- VT-3 of Control Rod Drive System Box Guide 0318A-W-201, Report No. Q2R22-004.

The inspectors reviewed the following examination records completed during the previous outage with relevant/recordable conditions/indications accepted for continued service to determine if acceptance was in accordance with the ASME Code Section XI or a NRC approved alternative.

- Leakage on Reactor Vessel and Class One Piping Leak Test (ISI) (Report No. 032-VT2); and
- Spring Load Setting on Support 1265-M-101 Was Found Outside of Tolerance (Report No. Q2R21-044).

The inspectors reviewed records for the following pressure boundary weld repairs completed for risk significant systems during the last outage to determine whether the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the construction code, and/or the NRC-approved code relief request. Additionally, the inspectors reviewed the welding procedure specifications and supporting weld procedure qualification records to determine whether the weld procedures were qualified in accordance with the requirements of the construction code and the ASME Code, Section IX.

- Remove and Replace a 2" High Pressure Coolant Injection System Sensing Line (WO No. 880895); and
- Perform a Half Nozzle Repair on Vessel Nozzle N-11B (WO No. 1529316).

b. Findings

No findings were identified.

.2 Reactor Pressure Vessel Upper Head Penetration Inspection Activities (Not Applicable)

.3 Boric Acid Corrosion Control (Not Applicable)

.4 Steam Generator Tube Inspection Activities (Not Applicable)

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of ISI related problems entered into the licensee's CAP and conducted interviews with licensee staff to determine if:

- the licensee had established an appropriate threshold for identifying ISI related problems;
- the licensee had performed a root cause (if applicable) and taken appropriate corrective actions; and
- the licensee had evaluated operating experience and industry generic issues related to ISI and pressure boundary integrity.

The inspectors performed these reviews to evaluate compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On May 5, 2014, the inspectors observed a crew of licensed operators in the plant's simulator during just-in-time training prior to plant startup from Refueling Outage Q2R22. The inspectors verified that corrective actions associated with procedural changes in Gland Seal System operation that were identified during the root cause review for the April 2, 2014 fire event (see Section 4OA3) were covered in sufficient detail.

On June 26, 2014, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures.

The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

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

b. Findings

No findings were identified.

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

a. Inspection Scope

On April 2, 2014, the inspectors observed the Unit 2 startup from Forced Outage Q2F66. During the startup, the station experienced a steam leak in the 'D' heater bay that eventually led to spurious annunciators and alarms in the Control Room. The unit was manually scrammed and eventually the licensee declared an Alert. The details and follow up inspection for this event are discussed in Section 4OA3. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- crew's clarity and formality of communications;
- ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms (if applicable);
- correct use and implementation of procedures;
- control board (or equipment) manipulations;
- oversight and direction from supervisors; and
- ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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 sample of licensed operator observations during periods of heightened activity/risk as defined in IP 71111.11.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

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

- Unit 2 250 VDC System; and
- Cable Aging Management and Monitoring Program.

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

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

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

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

b. Findings

No findings were identified.

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

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

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

- Unit 2 Risk Following Alert Declaration (see Section 4OA3), including: the loss of safety related equipment on Unit 2 due to the fire, the Shutdown Safety Management Plan associated with Q2R22, reactor disassembly, and cavity flood-up);
- Work Week 14-15-04 (Unit 1 online risk evaluation and Unit 2 outage week 2: switchyard work that impacted Unit 1, electrical configuration changes that impacted both units, and multiple changes to protected equipment configurations);
- Work Week 14-16-05 (Unit 1 online risk evaluation and Unit 2 outage week 3: electrical configuration changes and equipment outages that impacted risk on both units and multiple changes to protected equipment configurations);
- Work Week 14-17-06 (Unit 1 online risk evaluation and Unit 2 outage week 4: switchyard work that impacted risk on Unit 2, electrical configuration changes and equipment outages that impacted risk on both units, and multiple changes to protected equipment configurations);
- Work Week 14-22-11 (Unit 1 and Unit 2 online risk evaluation: Unit 1 emergent work and Unit 2 planned downpower).

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

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

These maintenance risk assessments and emergent work control activities constituted five 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:

- IR 1653444: 2-1001-29A LPCI Inject Valve Breaker Tripped During SDC Restoration;
- IR 1644102: Q2R22 Snubbers, Service Life Monitoring Snubber 2-099 UNSAT;
- Unit 2 Emergency Diesel Generator Cables that Were Accepted As-Is Following Fire in ‘D’ Heater Bay (see Section 4OA3 for event description);
- IR 1644595: U1 125 VDC Grounds Isolated – ATR Entered;
- ‘B’ SBGT Past Operability with ‘A’ SBGT Inoperable; and
- IR 1664739: Level III Ground on the Unit 1 125 VDC Battery System.

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 and 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 modifications:

- Unit 2 Emergency Diesel Generator Cable Temporary Modification 397653; and
- Unit 2 Emergency Diesel Generator Cable Permanent Modification 397693.

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(s). The inspectors, as applicable, 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. As applicable, the inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance. Documents reviewed are listed in the Attachment to this report.

This inspection constituted one temporary modification sample and one permanent plant modification sample 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:

- Unit 2 Emergency Diesel Generator Operability Testing Following Temporary Modifications to Cables in the ‘D’ Heater Bay;
- Unit 2 Reactor Core Isolation Cooling System Low and High Pressure Operability Tests Following Maintenance During Refueling Outage Q2R22;
- Unit 2 High Pressure Coolant Injection (HPCI) System Low and High Pressure Operability Test Following Maintenance During Refueling Outage Q2R22; and
- WO 01597844: HPCI Room Cooler Inspection Post Maintenance.

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

TS, 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 four 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

The inspectors reviewed the Outage Safety Plan (OSP) and contingency plans for the Unit 2 refueling outage (RFO), conducted April 5, 2014 through May 7, 2014, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the RFO, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- licensee configuration management, including maintenance of defense-in-depth commensurate with the OSP 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, accounting for instrument error;
- controls over the status and configuration of electrical systems to ensure that TS and OSP 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 leakage;
- startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the drywell (primary containment) to verify that debris had not been

left which could block emergency core cooling system suction strainers, and reactor physics testing; and

- licensee identification and resolution of problems related to RFO activities.

Documents reviewed are listed in the Attachment to this report.

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

b. Findings

(1) Seismic Scaffold in Contact with Safety-Related Equipment

Introduction: A finding of very low safety significance (Green) and associated NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified by the inspectors for the licensee's failure to meet the requirements of procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," when scaffold Q0178 was built with one of its supports in rigid contact with the operable Unit 2 Torus.

Description: Licensee Nuclear Engineering Standard NES-MS-04.1, "Seismic Prequalified Scaffolds," describes seismic requirements for clearances with respect to safety-related equipment. This document is also used as the "Station Scaffold Seismic Criteria", as discussed in licensee procedure MA-AA-716-025, "Scaffold Installation, Modification, and Removal Request Process." Table 2 of the NES document requires that the horizontal clearance to safety-related equipment in the Reactor Building at Quad Cities be 5-1/2 inches. Note 1 of Table 2 states, "All scaffolds shall meet the above horizontal clearance requirements for operable safety-related equipment or be clearance tied as specified…"

Procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," Attachment 1, "Scaffold Inspection Checklist," Step 16, requires the user to verify that the scaffold is "**NOT** supported by, in contact with or connected to safety related equipment." Step 3.1.7 states, "Scaffold shall **not** be attached to plant equipment without prior approval." Step 3.2.1 states, "Scaffolds requiring deviations from this procedure shall be approved by Engineering." Step 3.2.2 states, "As a minimum, seismic scaffolds will comply with specific requirements of approved procedures, unless approved by Engineering."

Procedure MA-AA-716-025, Attachment 2, "Non-Permanent Scaffold Request Form," Step B.1 states, "Can scaffold be erected per Station Seismic Scaffold Criteria?" If the answer is "No," then the procedure states that engineering involvement and approval is required for the scaffold. Engineering is also required to perform and document a post scaffold erection inspection in Step D.

On March 27, 2014, during a plant walkdown of the Unit 2 Reactor Building, with the unit in coast down, prior to unit shutdown for its upcoming refuel outage, the inspectors identified that scaffold Q0178 was built in rigid contact with the operable Unit 2 Torus contrary to procedure MA-AA-796-024, Attachment 1, "Scaffold Inspection Checklist." This checklist had been completed indicating no contact with any safety-related equipment. This condition was corrected when the inspectors informed site personnel and IR 1639356 was generated. On April 24, 2014, after reviewing corporate and seismic guidance, NES-MS-04.1, "Seismic Prequalified Scaffolds," the inspectors informed engineering that this scaffold did not have the required seismic spacing between the scaffold and the Unit 2 Torus. Engineering evaluated the scaffold and issued IR 1651581, which stated that NES-MS-04.1 guidance allowed closer tolerances if the scaffold is tied-off as described in the guidance. On April 25, 2014, the inspectors identified that the scaffold ties were not placed in accordance with licensee procedure NES-MS-04.1. The inspectors reviewed the site governing scaffold build procedures, MA-AA-796-024 and MA-AA-716-025. Procedure MA-AA-716-025, Step 4.1.2 states, in part, "The Station Seismic Scaffold Criteria were developed assuming conservatively restrictive conditions. Engineering may provide less restrictive criteria for an individual installation considering the location and anticipated plant conditions." For this scaffold, the inspectors noted that this scaffold was not tied-off as described in NES-MS-04.1, did not have the specified 5-1/2 inches clearance from the safety-related component without the tie-offs, and no documented evaluation was provided by engineering to accept this scaffold. However, engineering did sign off on the scaffold approval form.

On the same day, the inspectors walked down the Unit 1 Reactor Building, with the unit at full power. The inspectors identified that scaffold Q0532 was built in contact with the Unit 1 Reactor Core Isolation Cooling room drain pump discharge line. The MA-AA-796-024 Attachment 1, Scaffold Inspection Checklist, was checked indicating that it was not contacting any safety-related equipment. This condition was documented in IR 1639365. Engineering evaluated the condition in the condition report as being acceptable due to the scaffold configuration. The inspectors determined that engineering did not document a prior evaluation when the scaffold was not built in accordance with the station's seismic scaffold criteria. The inspectors determined that the lack of a documented engineering evaluation was a minor violation of the licensee's scaffold procedures because the scaffold configuration would not reasonably impact the operability of the RCIC system.

Also on March 27, during the plant walkdown, the inspectors identified that scaffold Q0530 was built in contact with a Service Air System header. This condition was documented in the CAP as IR 1639368, and corrected in the field. MA-AA-796-024, Step 3.1.7 states that scaffold "shall **not** be attached to plant equipment without prior approval." The inspectors determined that there was no documented prior approval for contact with plant equipment, as required by procedures. The inspectors determined that this represented a minor violation of procedures because the service air system is a non-safety related system.

On April 1, 2014, during a plant walkdown of the Unit 2 Reactor Building, with the unit shut down for forced outage Q2F66, the inspectors identified that scaffold Q0333, located in the 2B Core Spray room, was contacting room lighting contrary to the attached MA-AA-796-024 Attachment 1, "Scaffold Inspection Checklist," which stated that it was not contacting any "light fixtures or other electrical energy sources". The licensee did not capture this issue in their CAP, but the condition was corrected in the field. On April 25, 2014, a walkdown of the 2B Core Spray room revealed that scaffold Q0333 was erected to within 1 inch of the operable 2B Core Spray pump. Engineering stated that this support was sufficient for the scaffold in question and initiated IR 1657127. On May 5, 2014, the inspectors performed another walkdown of the scaffold in the 2B Core Spray room and determined that the scaffold was not tied-off per NES-MS-04.1. The inspectors determined that the scaffold was not built in accordance with the station seismic criteria as described in the Exelon Nuclear Engineering Standard document, nor was there an engineering evaluation documented for acceptability of the scaffold. Engineering, in this case, also signed off on the approval form. Again, the inspectors determined that these issues were considered minor violations because the scaffold configuration would not reasonably impact the operability of the core spray system.

The inspectors determined that there were multiple examples of scaffolds that did not meet the procedural requirements for seismic scaffolding. This showed the licensee's failure to maintain and implement their program for seismic scaffolding. The inspectors' violation, as described below, is focused on the scaffold that was in rigid contact with the unit 2 torus because it could have impacted the availability and reliability of the operable torus. The licensee is addressing the inspectors' concerns of the seismic scaffold program through their corrective action program.

<u>Analysis</u>: The inspectors determined that the licensee's failure to follow the station procedures for scaffold installation, inspection, and removal was a performance deficiency. Specifically, the seismic scaffold that was installed in contact with the safety-related Torus was contrary to MA-AA-796-024, and was a performance deficiency.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems Cornerstone attribute of protection against external factors and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, a scaffold built in contact with safety-related equipment could damage the equipment and affect its availability and reliability.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors answered, "No," to all of the Exhibit 2, "Mitigating Systems Screening Questions," in Section A and determined the finding was of very low safety significance (Green).

This finding has a cross-cutting aspect of documentation in the area of human performance because the licensee did not create and maintain complete, accurate and, up-to-date documentation. Specifically, the licensee did not completely and accurately evaluate the acceptability of a scaffold that was in contact with safety-related equipment (H.7).

<u>Enforcement</u>: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented procedures of a type appropriate to the circumstances and be accomplished in accordance with these procedures.

The licensee established MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," as the implementing procedure for building seismic scaffolding, an activity affecting quality. Procedure MA-AA-796-024, step 4.3.7 states, "**DOCUMENT** the results of scaffold inspection on the Scaffold Inspection Checklist." Attachment 1, "Scaffold Inspection Checklist," step 16, states that the scaffold is "<u>**NOT**</u> supported by, in contact with or connected to safety related equipment."

Contrary to the above, from March 25 to 27, 2014, the licensee failed to follow the requirements of Attachment 1 of MA-AA-796-024. Specifically, scaffold Q0178 was built in contact with the operable Unit 2 torus. This checklist had been completed indicating there was no contact with safety-related equipment.

Immediate corrective actions included modifying the scaffold such that it was no longer in contact with the Unit 2 torus.

Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 1639356, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000265/2014003-01, "Seismic Scaffold in Contact with Safety-Related Equipment")**.

.2 Other Outage Activities

a. Inspection Scope

The inspectors evaluated Unit 2 outage activities for an unscheduled forced outage that began on March 31, 2014, and continued through April 5, 2014. Unit 2 was shut down on March 31, 2014, as required by plant TS, after, on the same date, the licensee identified through-wall leakage on a control rod drive hydraulic control unit scram insert isolation valve. The inspectors reviewed activities to ensure that the licensee considered risk in developing, planning, and implementing the outage schedule.

The inspectors observed or reviewed the reactor shutdown and cooldown, outage equipment configuration and risk management, electrical lineups, selected clearances, control and monitoring of decay heat removal, control of containment activities, personnel fatigue management, startup and heatup activities, and identification and resolution of problems associated with the outage. The inspectors also observed portions of the maintenance and testing for the Unit 2 Control Rod Drive hydraulic control unit scram insert isolation valve.

Documents reviewed are listed in the Attachment to this report.

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 1600-07: Reactor Coolant System Leakage in the Drywell (DWFDS and DWEDS Available) (RCS);

- QCOS 1600-49: Unit 2 PCI Group 1 Isolation Test (Routine);
- WO 01713276-01: IM Division 1 MSL LO Pressure Cal/Functional WCIS 0200-60 (Routine);
- CFHP 0500-08: Refueling Interlocks (Routine);
- Unit 2 Division II ECCS Simulated Auto Actuation (IST); and
- WO 01534011: Local Leak Rate Test – Main Steam Isolation Valves and WO 01533639: Primary Sample Local Leak Rate Test (PCIV).

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

- did preconditioning occur;
- the effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges; and the calibration frequency was in accordance with TSs, the UFSAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy;
- applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability; tests were performed in accordance with the test procedures and other applicable procedures;
- jumpers and lifted leads were controlled and restored where used;
- test data and results were accurate, complete, within limits, and valid;
- test equipment was removed after testing;
- where applicable for 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 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 three routine surveillance testing samples, one in-service testing sample, one reactor coolant system leak detection inspection sample, and one containment isolation valve 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 a routine licensee emergency drill on June 19, 2014, and again on June 26, 2014, 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 in 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 samples as defined in IP 71114.06-05.

b. Findings

No findings were identified.

2. RADIATION SAFETY

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

This inspection constituted a partial sample as defined in IP 71124.01-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed all licensee performance indicators for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed the results of Radiation Protection Program audits (e.g., licensee's quality assurance audits or other independent audits). The inspectors reviewed any reports of operational occurrences related to occupational radiation safety since the last inspection. The inspectors reviewed the results of the audit and operational report reviews to gain insights into overall licensee performance.

b. Findings

No findings were identified.

.2 Radiological Hazard Assessment (02.02)

a. Inspection Scope

The inspectors determined if there have been changes to plant operations since the last inspection that may result in a significant new radiological hazard for onsite workers or members of the public. The inspectors evaluated whether the licensee assessed the potential impact of these changes and has implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from selected plant areas and evaluated whether the thoroughness and frequency of the surveys where appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and performed independent radiation measurements to verify conditions.

The inspectors selected the following radiologically risk-significant work activities that involved exposure to radiation:

- Unit 2 Inboard 1B and 1C Main Steam Isolation Valve Overhaul;
- Reactor Disassembly/Assembly/Cavity Work; and
- Drywell Scaffold Activities.

For these work activities, the inspectors assessed whether the pre-work surveys performed were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the Radiological Survey Program to determine if hazards were properly identified, including the following:

- identification of hot particles;
- the presence of alpha emitters;
- the potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials (This evaluation may include licensee planned entry into non-routinely entered areas subject to previous contamination from failed fuel.);
- the hazards associated with work activities that could suddenly and severely increase radiological conditions and that the licensee has established a means to inform workers of changes that could significantly impact their occupational dose; and
- severe radiation field dose gradients that can result in non-uniform exposures of the body.

The inspectors observed work in potential airborne areas and evaluated whether the air samples were representative of the breathing air zone. The inspectors evaluated whether continuous air monitors were located in areas with low background to minimize false alarms and were representative of actual work areas. The inspectors evaluated the licensee's program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

b. Findings

No findings were identified.

.3 Instructions to Workers (02.03)

a. Inspection Scope

The inspectors reviewed the following radiation work permits (RWP) used to access high radiation areas and evaluated the specified work control instructions or control barriers:

- RWP 10015089: Unit 2 Inboard 1B and 1C Main Steam Isolation Valve Overhaul;
- RWP 10015107: Reactor Disassembly/Assembly/Cavity Work; and
- RWP 10015187: Drywell Scaffold Activities.

For these radiation work permits, the inspectors assessed whether allowable stay times or permissible dose (including from the intake of radioactive material) for radiologically significant work under each radiation work permit were clearly identified. The inspectors evaluated whether electronic personal dosimeter alarm set-points were in conformance with survey indications and plant policy.

For work activities that could suddenly and severely increase radiological conditions, the inspectors assessed the licensee's means to inform workers of changes that could significantly impact their occupational dose.

b. Findings

No findings were identified.

.4 Contamination and Radioactive Material Control (02.04)

a. Inspection Scope

The inspectors observed locations where the licensee monitors potentially contaminated material leaving the radiological control area and inspected the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use and evaluated whether the work was performed in accordance with plant procedures and whether the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors assessed whether the radiation monitoring instrumentation had appropriate sensitivity for the type(s) of radiation present.

The inspectors reviewed the licensee's criteria for the survey and release of potentially contaminated material. The inspectors evaluated whether there was guidance on how to respond to an alarm that indicates the presence of licensed radioactive material.

The inspectors reviewed the licensee's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters. The inspectors assessed whether or not the licensee has established a *de facto* "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high radiation background area.

b. Findings

No findings were identified.

.5 Radiological Hazards Control and Work Coverage (02.05)

a. Inspection Scope

The inspectors evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels) during tours of the facility. The inspectors assessed whether the conditions were consistent with applicable posted surveys, RWPs, and worker briefings.

The inspectors evaluated the adequacy of radiological controls, such as required surveys, radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls. The inspectors evaluated the licensee's use of electronic personal dosimeters in high noise areas as high radiation area monitoring devices.

The inspectors assessed whether radiation monitoring devices were placed on the individual's body consistent with the licensee's procedures. The inspectors assessed whether the dosimeter was placed in the location of highest expected dose or that the licensee properly employed an NRC-approved method of determining effective dose equivalent.

The inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel in high radiation work areas with significant dose rate gradients.

The inspectors reviewed the following radiation work permits for work within airborne radioactivity areas with the potential for individual worker internal exposures:

- Unit 2 Inboard 1B and 1C Main Steam Isolation Valve Overhaul; and
- Turbine: Sandblasting Activities

For these RWPs, the inspectors evaluated airborne radioactive controls and monitoring, including potential for significant airborne levels (e.g., grinding, grit blasting, system breaches, entry into tanks, cubicles, and reactor cavities). The inspectors assessed barrier (e.g., tent or glove box) integrity and temporary high-efficiency particulate air ventilation system operation.

b. Findings

No findings were identified.

.6 Radiation Worker Performance (02.07)

a. Inspection Scope

The inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors assessed whether workers were aware of the radiological conditions in their workplace and the radiation work permit controls/limits in place, and whether their performance reflected the level of radiological hazards present.

b. Findings

No findings were identified.

.7 Radiation Protection Technician Proficiency (02.08)

a. Inspection Scope

The inspectors observed the performance of the radiation protection technicians with respect to all radiation protection work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace and the radiation work permit controls/limits, and whether their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

b. Findings

No findings were identified.

2RS2 Occupational As-Low-As-Reasonably-Achievable Planning and Controls (71124.02)

This inspection constituted a partial sample as defined in IP 71124.02-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspectors reviewed the plant's 3-year rolling average collective exposure.

The inspectors reviewed the site-specific trends in collective exposures and source term measurements.

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures as-low-as-reasonably-achievable (ALARA), which included a review of processes used to estimate and track exposures from specific work activities.

b. Findings

No findings were identified.

.2 Radiological Work Planning (02.02)

a. Inspection Scope

The inspectors selected the following work activities of the highest exposure significance:

- Unit 2 Inboard 1B and 1C Main Steam Isolation Valve Overhaul;

- Reactor Disassembly/Assembly/Cavity Work; and
- Drywell Scaffold Activities.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined whether the licensee reasonably grouped the radiological work into work activities based on historical precedence, industry norms, and/or special circumstances.

The inspectors assessed whether the licensee's planning identified appropriate dose mitigation features, considered alternate mitigation features, and defined reasonable dose goals. The inspectors evaluated whether the licensee's ALARA assessment has taken into account decreased worker efficiency from use of respiratory protective devices and/or heat stress mitigation equipment (e.g., ice vests). The inspectors determined whether the licensee's work planning considered the use of remote technologies (e.g., teledosimetry, remote visual monitoring, and robotics) as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspectors assessed the integration of ALARA requirements into work procedure and RWP documents.

b. Findings

No findings were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems (02.03)

a. Inspection Scope

The inspectors reviewed the assumptions and basis (including dose rate and man-hour estimates) for the current annual collective exposure estimate for reasonable accuracy for select ALARA work packages. The inspectors reviewed applicable procedures to determine the methodology for estimating exposures from specific work activities and the intended dose outcome.

The inspectors evaluated whether the licensee established measures to track, trend, and, if necessary, to reduce occupational doses for ongoing work activities. The inspectors assessed whether trigger points or criteria were established to prompt additional reviews and/or additional ALARA planning and controls.

The inspectors evaluated the licensee's method of adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors assessed whether adjustments to exposure estimates (i.e., intended dose) were based on sound radiation protection and ALARA principles or if they were just adjusted to account for failures to control the work. The inspectors evaluated whether the frequency of these adjustments called into question the adequacy of the original ALARA planning process.

b. Findings

No findings were identified.

.4 Source Term Reduction and Control (02.04)

a. Inspection Scope

The inspectors used licensee records to determine the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspectors assessed whether the licensee had made allowances or developed contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry.

b. Findings

No findings were identified.

.5 Radiation Worker Performance (02.05)

a. Inspection Scope

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice (e.g., workers are familiar with the work activity scope and tools to be used, workers used ALARA low-dose waiting areas) and whether there were any procedure compliance issues (e.g., workers are not complying with work activity controls). The inspectors observed radiation worker performance to assess whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

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 (RCS) leakage performance indicator for Quad Cities Unit 1 and Unit 2 for the period from April 1, 2013 through March 31, 2014. To determine the accuracy of the performance indicator (PI) data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 7, dated August 31, 2013, were used. The inspectors reviewed the licensee’s operator logs, RCS leakage tracking data, IRs, event reports and NRC integrated inspection reports for the period of April 1, 2013 through March 31, 2014 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment to this report.

This inspection constituted two RCS 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 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 follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

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

b. Findings

No findings were identified.

.3 Selected Issue Follow-Up Inspection: Apparent Cause Investigation Report for Fluctuating Voltage on Unit 1 250 VDC System

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized corrective action items documenting several issues associated with the Unit 1 safety-related 250 VDC Battery Chargers. The inspectors reviewed the equipment apparent cause evaluation 1631541 performed by the licensee following an unplanned inoperability of the Unit 1 battery charger that occurred on March 10, 2014. While the apparent cause evaluation was being performed, the battery charger had an additional unplanned inoperability on April 11, 2014. The inspectors reviewed conditions reports and corrective actions associated with the safety-related 250 VDC batteries generated since 2012, and noted a significant increase in the number of condition reports generated starting in October 2013. The inspectors additionally reviewed operations logs and work orders performed since October 2013. This review constituted one in-depth problem identification and resolution sample as defined in IP 71152-05.

b. Findings

(1) Post Maintenance Test Fails to Ensure Battery Charger Can Perform Function

Introduction: A finding of very low safety significance and associated NCV violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed for the licensee's failure to meet the requirements of MA-AA-716-012, "Post Maintenance Testing," which states, in part that post maintenance testing ensures that a component is able to perform its intended function and that the original deficiency is corrected. This finding had a cross-cutting aspect of Design Margins in the area of Human Performance because the licensee did not operate and maintain the battery charger within design margins.

Description: On March 10, 2014, the licensee declared the Unit 1 250 VDC battery charger inoperable when operators identified that the charger was not able to maintain battery terminal voltage greater than the TS lower limit of 260.4 VDC. Following troubleshooting on this issue, repairs to correct the condition were made and the battery was tested. Post maintenance testing of the battery was completed on March 25, 2014, using licensee procedure QCEMS 0210-01, "Battery Charger Testing for Safety Related 250 VDC Batteries". During the post-maintenance test, the licensee identified issues with the voltage stability characteristics of the charger. However, the results were accepted and the battery was declared operable because the battery was performing within the requirements of the TS.

On March 27, 2014, the licensee identified that the battery terminal voltage was low during operator rounds and battery voltage was adjusted into band and the condition was closed to trend. On April 2, 2014, the licensee noted that battery voltage was high out of band with a terminal voltage of 270.1 VDC, and the battery voltage was adjusted again. Finally, on April 11, 2014, the licensee identified that the battery terminal voltage had fallen below the TS minimum and declared the Unit 1 battery and charger inoperable, and began their complex troubleshooting process. The licensee identified a damaged float potentiometer, a failed voltage-regulating firing board thyristor, and an additional loose solder connection in the firing board. These issues, which had likely existed prior to the testing on March 25, were all corrected. The battery charger was tested and declared operable on April 15, 2014. The licensee noted that this test showed “excellent” voltage stability characteristics.

Through interviews with engineering personnel, the inspectors determined that the licensee identified voltage instabilities during the post maintenance testing conducted on March 25. However, the licensee accepted the test results because the instabilities were within the TS requirements for the battery. The inspectors were concerned that the acceptance criteria for the test did not give the necessary margin to ensure that the battery would continue to perform its function and maintain battery terminal voltage. In addition, the voltage instabilities noted during the test were not consistent with the operational history of the chargers. The inspectors also determined that the frequent adjustments that were needed with the U1 250 VDC charger in service were not consistent with operational history at Quad Cities and were indicative of a problem with the charger.

The inspectors reviewed CAP entries related to the battery chargers for the previous two-plus years (January 2012 to May 2015). The inspectors noted that the battery chargers had performed relatively reliably prior to October of 2013, and only identified 3 instances where the battery terminal voltage had to be adjusted into band by operators. From October 6, 2013 until March 10, 2014, the inspectors identified seven instances (as noted in the licensee’s apparent cause report) where the battery voltage either had to be adjusted into band or momentarily went out of band. The licensee determined that the voltage float potentiometer had been damaged in October 2013 during installation.

The inspectors determined that the post maintenance testing conducted on March 25, failed to meet the requirements of licensee procedure MA-AA-716-012, because the testing did not verify that the original deficiency that was causing the voltage stability issues had been corrected, nor did testing ensure that the battery charger would be able to perform its intended function while in service, as evidenced by the chargers inability to maintain the battery terminal voltage in band on multiple occasions, and the battery charger's subsequent inoperable condition on April 11, 2014 .

<u>Analysis</u>: Licensee procedure MA-AA-716-012, states, in part, that when maintenance is performed, the post maintenance testing ensures that a component is able to perform its intended function and that the original deficiency is corrected. Contrary to this, on March 25, 2014, the licensee’s post maintenance testing of the Unit 1 battery charger failed to meet the requirements of MA-AA-716-012, and was a performance deficiency. Specifically, licensee procedure QCEMS 0210-01, “Battery Charger Testing for Safety Related 250 VDC Batteries,” failed to ensure that the battery charger would be able to perform its intended function and that the original deficiency was corrected.

The finding was determined to be more than minor because the finding was associated with the Mitigating Systems cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

Specifically, the voltage instabilities associated with the Unit 1 250 VDC battery charger affected the availability and reliability of the battery charger performing its functions and led to multiple unplanned inoperable conditions.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process (SDP) for Findings At-Power." The inspectors answered, "No," to all of the Exhibit 2, "Mitigating Systems Screening Questions," in section A and determined the finding was of very low safety significance (Green).

This finding had a cross-cutting aspect of Design Margins in the area of Human Performance because the licensee did not operate and maintain the battery charger within design margins. Specifically, the licensee's post maintenance testing acceptance criteria did not give them enough margin to prevent the battery from becoming inoperable. (H.6)

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that procedures for activities affecting quality shall include qualitative or quantitative acceptance criteria for determining that those important activities have been satisfactorily accomplished. The licensee established procedure QCEMS 0210-01, "Battery Charger Testing for Safety Related 250 VDC Batteries," as the implementing procedure for ensuring that 250 VDC safety-related battery chargers could perform their intended function, an activity affecting quality.

Contrary to the above, prior to April 15, 2014, licensee procedure QCEMS 0210-01 failed to include quantitative and qualitative acceptance criteria for determining that the Unit 1 250 VDC battery charger could perform its intended function. Specifically, procedure QCEMS 0210-01, failed to include acceptance criteria for voltage stability characteristics and thyristor conduction for determining that the battery charger could perform its intended function.

Immediate corrective actions included replacing the float potentiometer in the battery charger circuitry, replacing a thyristor in the voltage regulation circuitry, and correcting a loose solder connection identified in the battery charger circuitry. Planned corrective actions include revising procedure QCEMS 0210-01 to include acceptance criteria that ensure the battery chargers can satisfactorily perform their intended function.

Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 1631541, the violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000254/2014003-02, "Post Maintenance Test Fails to Ensure Battery Charger Can Perform Function")**.

.4 Selected Issue Follow-Up Inspection: Increase in Unit 2 Drywell Equipment Drain and Floor Drain Sump Leakage

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting issues associated with the Unit 2 drywell equipment drain and floor drain sumps. The inspectors reviewed condition reports and corrective actions associated with increased leakage in the drywell equipment drain and floor drain sumps starting in May 2014. The inspectors additionally reviewed operations logs and engineering trend analysis since May 2014. 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 Follow-Up Inspection: Root Cause Investigation Report for the Alert and Fire Event on April 2, 2014

a. Inspection Scope

The inspectors reviewed the licensee's root cause investigation report and reviewed the identified root cause and contributing causes to the fire event that occurred on April 2, 2014 (see Section 4OA3 for event description and findings). The inspectors also reviewed associated corrective actions and extent of condition reviews, both completed and planned.

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

b. Findings

No findings were identified.

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

.1 Review of Actions Associated with Unit 2 'D' Heater Bay Cable Fire

a. (Closed) Licensee Event Report 05000265/2014-002-00: Cable Tray Fire Caused By Non-Conforming Cable Routing

The inspectors reviewed the plant's response to an event that occurred during the Unit 2 startup on April 2, 2014, and resulted in an 'Alert' Emergency Action Level (EAL). At 12:28 p.m., with the reactor in Mode 2 and reactor power at approximately 8 percent, a Fire Alarm System (FAS) alarm was received for the Unit 2 'D' Heater Bay area. Operators were dispatched to the area and initial entry into the heater bay identified a steam leak, with no indications of a fire. Operators in the field were able to identify the location of the leak as coming from the Gland Seal System. Control Room operators made the decision to transition to Mode 1, in an attempt to bring the main turbine online, so they could eventually isolate the source of the steam leak. Within minutes of transitioning into Mode 1, the control room received various spurious alarms and electrical system anomalies, including several DC ground annunciators. Unit 2 was manually scrammed, the turbine was tripped and the main steam isolation valves (MSIVs) were closed to ensure the steam leak was isolated. Operators in the Turbine Building identified sparks and smoke outside of the 'D' Heater Bay and reported the condition to the Control Room. Operators made an attempt to enter the heater bay, but they encountered heavy black smoke at the door (This was later determined to be from a fire in a cable tray in the 'D' Heater Bay.). The fire was extinguished by the automatic fire suppression system. At 1:40 p.m., due to smoke observed in safety-related Motor Control Center (MCC) 29-1 in the Reactor Building, an Alert level emergency was declared per EAL HA3, involving a fire in a vital area affecting safety system equipment. The Alert was eventually terminated at 9:32 p.m.

Although this event involved an electrical fire/arc and subsequent insulation fire, the fire was extinguished by installed, automatic suppression prior to extending beyond the immediate area. The fire, and associated cable damage, caused isolated CPTs to overheat, smoke in various MCCs and breakers to trip. There were spurious alarms generated in the Control Room. However, no equipment unexpectedly started or stopped. No additional fires were initiated beyond the top and bottom cable trays in the immediate area. There were no difficulties encountered during the unit shutdown or subsequent reactor depressurization and cool-down.

The inspectors interviewed engineering and operations personnel and reviewed various documents to develop a timeline of events that occurred.

Quad Cities Alert Timeline April 2, 2014:

04:40 a.m. Unit 2 reactor critical.

12:37 p.m. Main Control Room received a FAS notification that smoke had been detected in the ‘D’ Heater Bay.

12:38 p.m. Fire brigade leader dispatched to the ‘D’ heater bay.

12:48 p.m. Fire brigade leader reported to the MCR that there was no fire or smoke, but that there was an extensive steam leak.

12:58 p.m. Unit 2 mode switch taken to Run for Mode 1.

1:02 p.m. Main Control Room received numerous unexpected alarms and observed other anomalous indications on the panels. Unit supervisor directed unit scram.

1:03 p.m. Manual reactor scram.

1:05 p.m. Turbine trip.

1:07 p.m. Unit supervisor actuated the plant fire siren and dispatched the fire brigade and another fire brigade leader to assist with fire brigade leader duties.

1:12 p.m. MSIVs closed to isolate steam leak.

1:15 p.m. Main Control Room received notification of smoke at the Unit 2 Hydrogen Seal Oil vacuum pump breaker cubicle in MCC 28-2.

1:17 p.m. Main Control Room received notification of thick black smoke in ‘D’ Heater Bay.

1:21 p.m. East side of turbine fire annunciator alarm.

1:25 p.m.	Main Control Room received report of heavy black smoke in 'D' Heater Bay and report of smoke from safety-related Bus 29-1.
1:27 p.m.	Unit Supervisor ordered MCC 29-1 de-energized.
1:40 p.m.	Alert declared per HA3 involving a fire in a vital area affecting safety system equipment.
1:57 p.m.	Technical Support Center activated.
2:02 p.m.	Report of all steam leaks stopped.
2:18 p.m.	All fires in cable tray extinguished.
2:22 p.m.	Transfer of command and control to Emergency Offsite Facility.
8:01 p.m.	Smoke was reported coming from MCC 25-1.
8:07 p.m.	MCC 25-1 de-energized.
9:32 p.m.	Alert terminated.

The licensee conducted a root cause investigation for this event. The investigation team determined that the fire was caused by humidity and condensate from the steam leak in the heater bay that provided an environment for an existing flaw in an electrical cable to fault to ground. The root cause was determined to be the improper routing of the safety-related Instrument Bus and ESS cables. These cables did not meet ComEd Standard N-EM-0035 for the minimum static bend radius of 3.5 inches for this cable type (see NCV 05000265/2014003-03 below). The steam leak was determined to be due to a relief valve lifting in the Main Turbine Gland Seal System as a result of improper operation of the system during start up (see NCV 05000265/2014003-04 below), and the failure of the relief valve downstream expansion joint, which had been in a reversed orientation since original construction. The inspectors determined that the reversed installation of the relief valve downstream expansion joint was not a performance deficiency because there was no requirement to verify the orientation of the installation for this component. The corrective actions for this event included repairing cables damaged in the fire, including the instrument bus and ESS bus cables; replacement of the relief valve and the downstream expansion joint; and revision to the gland seal operating procedures.

Inspectors reviewed several issues related to this event under this and other inspection procedures, including:

- Operator Actions During and Following the Event
- Activation of the Emergency Response Organization
- Extent of Condition;
- Previous Plant Operating History;
- EAL Declaration and Notification Requirements;
- Control Room Logs;
- Environmental Qualification Program;
- Aging Management Program;

- Cable Design;
- System Health Reports;
- Corrective Maintenance Work Orders;
- License Renewal Commitments;
- Equipment Alignment (Section 1R04);
- Fire Protection (Section 1R05);
- Licensed Operator Requalification Program (Section 1R11);
- Maintenance Rule (Section 1R12);
- Risk Assessments And Protected Equipment (Section 1R13);
- Operability Determinations (Section 1R15);
- Temporary And Permanent Plant Modifications (Section 1R18);
- Post Maintenance Testing (Section 1R19); and
- Problem Identification and Resolution (Section 4OA2).

Documents reviewed are listed in the attachment to this report.

The findings associated with this event are documented below. This Licensee Event report (LER) is closed.

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

b. Findings

(1) Failure to Meet Design Requirements for Safety-Related Cables in 'D' Heater Bay

Introduction: A finding of very low safety significance (Green) with an associated NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was self-revealed for the licensee's failure to demonstrate compliance with ComEd Standard N-EM-0035 for safety-related cables within the Unit 2 'D' Heater Bay. Specifically, the licensee failed to route the instrument bus and ESS bus cables with minimum cable static bend radius requirements in a manner consistent with N-EM-0035 resulting in an event that caused a fire in the turbine building, smoke in various MCC cubicles due to overheated control power transformers (including one safety-related MCC), a manual scram and main steam isolation, and an Alert emergency declaration.

Description: On April 2, 2014, there was a fire event at the Quad Cities Generating Station as described in section 4OA3.1 of this report. The fire in the 'D' Heater Bay was initiated when the humidity and condensate from the steam leak provided the environment necessary for an existing flaw in an electrical cable to fault to ground. The root cause for this event (i.e., source of the cable flaw) was identified by the licensee as routing of the Instrument Bus and ESS Bus cables in a manner inconsistent with the current standard for minimum static bend radius for this type and size of cable. Specifically, the minimum static bend radius of 3.5 inches specified in ComEd Standard N-EM-0035 was not met. The routing for these cables (i.e., on the bottom of the tray, resting across rungs, and exiting at a sharp angle down into a 40-foot vertical run) created a condition such that the mechanical stress on the cables would result in failure before the end of design life. This condition was introduced during original construction. The Instrument Bus and ESS Bus cables were installed at the bottom of a horizontal ladder-type cable tray. The cables then exited the cable tray downward from the bottom of the tray and entered a cable riser. This resulted in the cables sitting on the rungs of the ladder-type cable tray, with the weight of other cables on top of them, and then draping down across one of the rungs to enter the cable riser at a static bend radius that did not meet standard requirements. The geometry of the ladder rung where the arc fault initiated to the riser below and the routing of the surviving Instrument Bus neutral indicates a routing that is inconsistent with ComEd Standard N-EM-0035. The fire in the 'D' Heater Bay was initiated when the humidity and condensate from the steam leak provided the environment necessary for an existing flaw in an electrical cable to fault to ground.

The licensee entered issues related to the failure to follow bend radius requirements as IR 1642409, "Existing Cable Flaw," dated May 6, 2014.

<u>Analysis</u>: The inspectors determined that the failure to install Instrument and ESS bus safety-related cables in accordance with ComEd standard, N-EM-0035, was contrary to the requirements of 10 CFR Part 50, Appendix B Criterion III, "Design Control" and was a performance deficiency. Specifically, the Instrument and ESS bus safety-related cables were not installed with a minimum static bend radius of 3.5 inches, as required by standard N-EM-0035.

The finding was determined to be more than minor per IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was a precursor to a significant event. Specifically, failure to install Instrument Bus and ESS cables in accordance with the requirements of N-EM-0035 resulted in the initiation of an electrical fault and cable fire. The fire resulted in a manual reactor scram and the loss of safety-related equipment. The performance deficiency was associated with the Reactor Safety - Initiating Events Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the capability of equipment relying on the power supply form Instrument and ESS buses, both during shutdown as well as power operations.

In accordance with IMC 0609, "Significance Determination Process," Attachment 0609.04, "Phase 1 – Initial Screening and Characterization of Findings," dated September 20, 2013, Table 2, "Cornerstones Affected by Degraded Condition or Programmatic Weaknesses," the inspectors determined that the performance deficiency was an external event (fire) initiator and therefore, affected the Initiating Events Cornerstone. In accordance with Table 3, "SDP Appendix Router," screening under IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," dated June 19, 2012, was required. Since the cable fault resulted in a fire, the inspectors answered "Yes" to the Exhibit 1 – Initiating Event Screening Questions, Section E, "External Event Initiators," question of whether the finding impacted the frequency of a fire initiating event. Therefore a detailed risk evaluation was performed by the SRAs using IMC 0609, Appendix A and other reference documents described below.

The Quad Cities Standardized Plant Analysis Risk (SPAR) model version 8.18 and SAPHIRE version 8.0.9.0 was used to calculate a Conditional Core Damage Probability (CCDP) and a Conditional Large Early Release Probability (CLERP) for this event. Unit 1 was used as a surrogate for Unit 2 because the SPAR model is based on Unit 1. In accordance with Risk Assessment of Operational Events Handbook guidance, for findings that cause initiating events to occur, the initiating event that was observed is set to 1.0 and the CCDP is calculated. The CCDP is multiplied by one inverse year (yr-1) to equate this to a change in core damage frequency for the performance deficiency.

The risk analysis was performed with the following assumptions due to the equipment that was observed to be failed during the event:

- A “Transient” initiating event was used due to the manual reactor scram that was initiated.
- A failure of the MSIVs to remain open due to the manual closure of the valves.
- The failure of the following equipment associated with MCC 29-1 was assumed with the basic events for these components set equal to a failure probability of 1.0:

  - 2B low pressure core spray pump
  - emergency diesel general 2
  - 2B standby liquid control pump
  - 2A turbine building closed cooling water pump was assumed failed (fed from MCC 25-1 – failure probability set to 1.0)

The 2B RHR pump miniflow valve 18B was de-energized in the OPEN position during the event. The availability of the 2B RHR pump was evaluated to be unaffected with the valve failed in the OPEN position.

For the equipment that was rendered unavailable as described above, the result was a CCDP of 5.32E-7. The dominant sequences were associated with (1) a transient initiating event with various Anticipated Transient Without Scram (ATWS) sequences with a failure of the power conversion system, and (2) a transient initiating event with a failure of the following:

- power conversion system
- main feedwater
- suppression pool cooling
- power conversion system recovery
- containment venting
- late injection

However, the delta risk is required to account for the potential unavailability of risk-significant equipment due to equipment failure. If the wet pipe sprinkler system had failed to function, it was conservatively assumed that all the cables in the affected cable trays 852B and 853T and riser R269 would have failed. The probability that the wet pipe suppression system would have failed to function is 2E-2 (per NUREG/CR-6850, “Fire PRA Methodology for Nuclear Power Facilities,” Appendix P). If all the affected cables had failed, then based on input from the licensee, in addition to the loads mentioned above, Bus 29 would also have been unavailable due to loss of its control power. The result of a risk assessment if Bus 29 was unavailable (in addition to the loads mentioned above) was a CCDP of 6.31E-6. The adjusted CCDP based on actual failed equipment and the potential unavailability of the Wet Pipe Sprinkler system is then obtained as:

CCDP (adjusted) = 5.32E-7 + (2E-2)(6.31E-6 – 5.32E-7) = 6.48E-7

The result is a delta core damage frequency (ΔCDF) of 6.48E-7/yr.

Quad Cities Unit 2 has a Mark I containment. The SRAs used IMC 0609 Appendix H, “Containment Integrity Significance Determination Process” dated May 6, 2004, to evaluate the potential risk contribution due to LERF. The finding was a “Type A” finding in which the finding has an impact on core damage frequency. The dominant sequences involved long-term accident sequences that involve failure of containment heat removal that eventually progresses to containment failure.

For the equipment that was rendered unavailable, the CLERP was determined to be 5.44E-8 based on the following:

- Anticipated Transient Without Scram sequences (SPAR sequences starting with 59) contributed a CCDP of 1.31E-7. With a Large Early Release Frequency (LERF) factor of 0.3 for ATWS sequences, this results in a CLERP of 3.93E-8.
- High Reactor Coolant System sequences (SPAR sequences 30 and 56 for Transients) contributed a CCDP of 8.91E-9. With a LERF factor of 0.6 for High RCS sequences, this results in a CLERP of 5.35E-9.
- The total CLERP is the sum of the above sequences or 4.47E-8.

However, as above, the delta risk was increased with the conservative assumption that all the cables in the affected cable trays 852B and 853T and riser, R269, would have failed if the fire was not extinguished. As mentioned above, the probability that the wet pipe suppression system would have failed to function is 2E-2. With Bus 29 unavailable (in addition to the loads mentioned above), the CLERP was determined to be 1.63E-6 based on the following:

- ATWS sequences (SPAR sequences starting with 59) contributed a CCDP of 1.46E-7. With a LERF factor of 0.3 for ATWS sequences, this results in a CLERP of 4.38E-8.
- High Reactor Coolant System sequences (SPAR sequences 30 and 56 for Transients) contributed a CCDP of 2.64E-6. With a LERF factor of 0.6 for High RCS sequences, this results in a CLERP of 1.58E-6.
- The total CLERP is the sum of the above sequences or 1.62E-6.

The adjusted CLERP based on the potential unavailability of the wet pipe sprinkler system is then obtained as:

CLERP (adjusted) = 4.47E-8 + (2E-2)(1.62E-6 – 4.47E-8) = 7.63E-8

The result is a delta LERF (ΔLERF) of 7.63E-8/yr.

Based on the detailed risk evaluation, the SRAs determined that the finding was of very low safety-significance (Green).

Therefore, the finding screened to Green, and no further analysis is required. The finding is associated with the Initiating Systems Cornerstone attribute of Design Control, and affected the cornerstone objective of ensuring the capability of equipment relying on the power supply form Instrument and ESS buses both during shutdown as well as power operations. There are no assumptions used in the finding’s safety significance determination.

The finding does not have a cross-cutting aspect, because it is associated with a performance deficiency from the timeframe of the plant’s original construction and is not representative of the licensee’s current performance.

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires that licensees establish measures and include provisions to assure that appropriate quality standards as specified in design documents and deviations from such standards are controlled. Licensee's ComEd Standard, N-EM-0035, assumed a minimum static bend radius of 3.5 inches for all safety-related cables routed within the 'D' heater bay.

Contrary to the above, as part of original plant construction, the licensee did not establish measures to assure appropriate quality standards for cable routing. Specifically, the routing for the Unit 2 safety-related Instrument Bus and ESS cables did not meet the requirements of ComEd Standard N-EM-0035. Specifically, the cables routed on the bottom of the tray, resting across rungs, and exiting down into a 40-foot vertical run, with a static bend radius of less than 3.5 inches and created a condition such that the mechanical stress on the cable caused a flaw before the end of its design life. The licensee's corrective actions for this event included repairing cables damaged in the fire, replacing the expansion joint; and revising the Steam Seal operating procedures.

This violation is being treated as an NCV (Green), consistent with Section 2.3.2 of the Enforcement Policy because it was of very low safety significance and was entered into the licensee's corrective action program as IR 1642409. **(NCV 05000265/2014003-03, "Failure to Meet Design Requirements for Safety-Related Cables in 'D" Heater Bay")**.

(2) Failure to Operate the Gland Seal System as Designed

Introduction: A finding of very low safety significance (Green) and associated NCV of TS Section 5.4.1 was self-revealed on April 2, 2014, because the licensee failed to establish a procedure in accordance with the requirements of Regulatory Guide 1.33. Specifically, the procedure that the licensee used for startup of the Gland Seal system failed to include provisions to ensure that the steam seal regulator bypass valve, 2-3099-S2 (S2), was closed prior to lifting the steam seal bypass relief valve.

Description: On April 2, 2014, there was a fire event at the Quad Cities Generating Station as described in Section 4OA3.1 of this report. The fire was caused by humidity and condensate from the steam leak in the heater bay that provided an environment for an existing flaw in an electrical cable to fault to ground. Part of the licensee's root cause evaluation investigated the cause of the steam leak from the Gland Seal system, which was determined to have come from an expansion joint that had ruptured downstream of the bypass line relief valve. Ultimately, the licensee's root cause investigation determined that the procedure for operation of the Gland Seal system was not adequate to prevent the bypass piping from being operated at pressures greater than it was designed, and led to the failure of the piping and a significant steam leak in the 'D' Heater Bay. The root cause investigation also determined that the downstream expansion joint had been installed in a reverse orientation since original construction, which was a contributing cause to the failure of the expansion joint.

In June 2013, the licensee identified packing leakage from the steam seal feed valve, 2-3099-S1 (S1). In September 2013, the S1 packing leakage increased, and the licensee made a decision to close the valve. The S1 is required during startup of the Main Steam and Turbine Systems and normally kept open while operating, though the gland seal system can continue to function with the S1 closed, once at normal steam pressures. The licensee had a plan to fix this leak during the refueling outage.

However, they did not include this work into a forced outage scope. The licensee was forced to shut down Unit 2 due to an unrelated issue on March 31, 2014, and attempted to startup on April 2, 2014, prior to repairing the S1 valve. The packing leak on S1 caused the operators to have trouble while starting up the Gland Seal system, as described below.

Procedure QCGP 1-2, “Normal Unit 2 Startup,” addresses startup of the reactor, including startup of the Main Steam System and turbine. Step F.6.d, states, “Establish a vacuum in the Main Condenser per QCOP 5400-01.” QCOP 5400-01, “Off-Gas System Startup Operation,” Step F.1 directs operators to place the Gland Seal System in operation per QOP 5600-01.

Procedure QOP 5600-01, “Gland Seal System Operation,” was used by the licensee during startup of the Main Steam and Turbine-Generator systems. Step F.1.g. stated, “WHEN Main Steam pressure is > 100 psig AND Steam Seal pressure regulator is able to maintain Gland Seal supply pressure between 2.5 and 5.0 psig, THEN close S2.” During reactor startup on April 2, 2014, operators were unable to maintain Gland Seal supply pressure between 2.5 and 5.0 (due to the packing leak on S1), and therefore did not shut the S2 valve because the pressure regulator was unable to maintain system pressure. The inspectors determined the procedure did not have guidance that directed actions to perform if the S1 valve was unable to maintain pressure >100 psig. The inspectors also determined the procedure did not include provisions to ensure that the S2 valve was shut prior to exceeding the bypass line relief valve setpoint or the bypass line design pressure.

As operators continued the reactor heatup and raise reactor pressure, they eventually received the “Bypass to Steam Seal High Pressure Alarm.” Procedure QOA 900-7 A-10, “901-7 (902-7) Row ‘A’ Annunciator Procedures,” is the annunciator response procedure for the “Bypass to Steam Seal High Press” alarm. Operator action step 1 states, “IF putting on steam seals AND MO-S2 is open, THEN close MO-S2 to reduce pressure below alarm point.” The operators were unable to maintain Gland Seal supply pressure by closing S2, and as they attempted to throttle S2 closed, they would receive the “STM SEAL HDR LOW PRESS” alarm.

Procedure QOA 900-7 F-12, “901-7 (902-7) Row F Annunciator Procedures,” is the annunciator response procedure for the “STM SEAL HDR LOW PRESS” alarm in the control room. Immediate Operator Action step 2 states, “IF Steam Seal Feed Valve is unable to maintain desired pressure, THEN open Steam Seal Regulator Bypass valve 2-3099-S2 as necessary to maintain 2.5-5.0 psig pressure, as indicated on gauge 2-5640-69.” The operators were faced with conflicting procedural guidance when one stated to close S2, while the other directed opening S2 for the alarm indications. However, they continued with the reactor startup. This issue is discussed in the cross-cutting aspect assigned to this finding in the analysis section.

The licensee determined that during the reactor heatup and pressurization, the bypass line relief valve setpoint was exceeded, the valve lifted multiple times, and eventually the valve failed. The licensee also determined that pressure in the bypass line exceeded the design pressure of the expansion joint, which eventually failed, causing a significant steam leak in the ‘D’ Heater Bay. The steam leak and the resultant high humidity environment in the heater bay eventually caused a fire in a cable tray when the degraded cabling faulted.

Analysis: The inspectors determined that opening the Gland Seal System steam seal regulator bypass valve, S2, at pressures greater than the bypass line relief valve design pressure and system design pressure was a performance deficiency.

The performance deficiency was determined to be more than minor and a finding because it was a precursor to a significant event. Specifically, the Gland Seal System bypass line was opened at pressures that the bypass line was not designed to withstand. On April 2, 2014, during reactor and steam system startup, opening of the S2 valve led to the lifting of the Gland Seal System bypass line relief valve. The relief valve lifted multiple times and was a contributing cause to the failure of the downstream expansion joint, a significant steam leak in the 'D' Heater Bay, and the resulting fire caused by a degraded cable fault. The inspectors concluded this finding was associated with the Initiating Events Cornerstone.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, "Significance Determination Process," Appendix A, "The Significance Determination Process for Findings at Power," Exhibit 1, "Initiating Events Screening Questions," and answered "Yes" to Question B on Transient Initiators, because the resulting steam leak led to a fire in the Turbine Building, the loss of safety related equipment, a manual scram, manual main steam isolation to stop the steam leak, and an Alert emergency declaration. The inspectors determined that a Detailed Risk Evaluation was required.

The Quad Cities SPAR model version 8.18 and SAPHIRE version 8.0.9.0 was used to calculate a CCDP and a CLERP for this event. Unit 1 was used as a surrogate for Unit 2 because the SPAR model is based on Unit 1. In accordance with Risk Assessment of Operational Events Handbook guidance, for findings that cause initiating events to occur, the initiating event that was observed is set to 1.0 and the CCDP is calculated. The CCDP is multiplied by one inverse year (yr-1) to equate this to a change in core damage frequency for the performance deficiency.

The risk analysis was performed with the following assumptions due to the equipment that was observed to be failed during the event:

- A "Transient" initiating event was used due to the manual reactor scram that was initiated.
- A failure of the MSIVs to remain open due to the manual closure of the valves.
- The failure of the following equipment associated with MCC-29-1 was assumed with the basic events for these components set equal to a failure probability of 1.0:

  - 2B Low Pressure Core Spray Pump
  - Emergency Diesel General 2
  - 2B Standby Liquid Control Pump

- 2A Turbine Building Closed Cooling Water pump was assumed failed (fed from MCC 25-1 – failure probability set to 1.0)

The 2B RHR pump miniflow valve 18B was de-energized in the OPEN position during the event. The availability of the 2B RHR pump was evaluated to be unaffected with the valve failed in the OPEN position.

For the equipment that was rendered unavailable as described above, the result was a CCDP of 5.32E-7. The dominant sequences were associated with (1) a transient initiating event with various Anticipated Transient Without Scram (ATWS) sequences with a failure of the Power Conversion System, and (2) a transient initiating event with a failure of the following:

- Power Conversion System
- Main Feedwater
- Suppression Pool Cooling
- Power Conversion System Recovery
- Containment Venting
- Late Injection

However, the delta risk is required to account for the potential unavailability of risk-significant equipment due to equipment failure. If the wet pipe sprinkler system had failed to function, it was conservatively assumed that all the cables in the affected cable trays 852B and 853T and riser R269 would have failed. The probability that the wet pipe suppression system would have failed to function is 2E-2 (per NUREG/CR-6850, "Fire PRA Methodology for Nuclear Power Facilities," Appendix P). If all the affected cables had failed, then based on input from the licensee, in addition to the loads mentioned above, Bus 29 would also have been unavailable due to loss of its control power. The result of a risk assessment if Bus 29 was unavailable (in addition to the loads mentioned above) was a CCDP of 6.31E-6. The adjusted CCDP based on actual failed equipment and the potential unavailability of the Wet Pipe Sprinkler system is then obtained as:

CCDP (adjusted) = 5.32E-7 + (2E-2)(6.31E-6 – 5.32E-7) = 6.48E-7

The result is a delta core damage frequency (ΔCDF) of 6.48E-7/yr.

Quad Cities Unit 2 has a Mark I containment. The SRAs used IMC 0609 Appendix H, "Containment Integrity Significance Determination Process" dated May 6, 2004, to evaluate the potential risk contribution due to large early release frequency (LERF). The finding was a "Type A" finding in which the finding has an impact on core damage frequency. The dominant sequences involved long-term accident sequences that involve failure of containment heat removal that eventually progresses to containment failure.

For the equipment that was rendered unavailable, the CLERP was determined to be 5.44E-8 based on the following:

- ATWS sequences (SPAR sequences starting with 59) contributed a CCDP of 1.31E-7. With a LERF factor of 0.3 for ATWS sequences, this results in a CLERP of 3.93E-8.
- High Reactor Coolant System sequences (SPAR sequences 30 and 56 for Transients) contributed a CCDP of 8.91E-9. With a LERF factor of 0.6 for High RCS sequences, this results in a CLERP of 5.35E-9.
- The total CLERP is the sum of the above sequences or 4.47E-8.

However, as above, the delta risk was increased with the conservative assumption that all the cables in the affected cable trays 852B and 853T and riser R269 would have failed if the fire was not extinguished. As mentioned above, the probability that the wet pipe suppression system would have failed to function is 2E-2. With Bus 29 unavailable (in addition to the loads mentioned above), the CLERP was determined to be 1.63E-6 based on the following:

- ATWS sequences (SPAR sequences starting with 59) contributed a CCDP of 1.46E-7. With a LERF factor of 0.3 for ATWS sequences, this results in a CLERP of 4.38E-8.
- High Reactor Coolant System sequences (SPAR sequences 30 and 56 for Transients) contributed a CCDP of 2.64E-6. With a LERF factor of 0.6 for High RCS sequences, this results in a CLERP of 1.58E-6.
- The total CLERP is the sum of the above sequences or 1.62E-6.

The adjusted CLERP based on the potential unavailability of the Wet Pipe Sprinkler system is then obtained as:

CLERP (adjusted) = 4.47E-8 + (2E-2)(1.62E-6 – 4.47E-8) = 7.63E-8

The result is a delta LERF (ΔLERF) of 7.63E-8/yr.

Therefore, based on the detailed risk evaluation, the SRAs determined that the finding was of very low safety-significance (Green).

The inspectors determined that a principal contributor to the finding was that the licensee did not stop when faced with uncertain conditions and risks were not evaluated and managed before proceeding. Specifically, when the licensee identified a steam packing leak in the S1 valve in June 2013 and decided to close the valve when leakage increased to an unacceptable level in October 2013, they failed to recognize the risk and prioritize the repair of the valve prior to reactor startup on April 2, 2014. In addition, when operators faced unexpected system response during the startup of the Gland Seal System and conflicting procedural guidance, the cause of the problem was not thoroughly understood and evaluated prior to continuing the system startup. As a result, the inspectors assigned a cross-cutting aspect of Challenge the Unknown in the area of human performance (H.11).

Enforcement: TS Section 5.4.1 states, in part, that “written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978.”

NRC Regulatory Guide 1.33, Appendix A, Sections 4.l and 4.m states, “Instructions for… startup… and changing modes of operation should be prepared, as appropriate, for the Main Steam System (reactor vessel to turbine) and Turbine-Generator System,” respectively. Licensee procedure QOP 5600-01, “Gland Seal System Operation,” was used by the licensee during startup of the Main Steam and Turbine-Generator Systems.

Contrary to the above, between October 2013 and April 2, 2014, the licensee failed to establish a procedure to address the requirements of Regulatory Guide 1.33, Appendix A, Sections 4.l and 4.m. Specifically, licensee procedure QOP 5600-01, “Gland Seal System Operation,” was used during startup of the Main Steam and Turbine-Generator Systems. However, the procedure failed to include provisions to ensure that the S2 valve was closed prior to lifting the steam seal bypass relief valve and exceeding the bypass line design pressure, which resulted in a failure of the piping and a significant steam leak in the ‘D’ Heater Bay.

Immediate corrective actions taken by the licensee included revising their procedures for operation of the Gland Seal System and conducting just-in-time training on Gland Seal System operation for operators prior to the subsequent startup on Unit 2. In addition, the licensee planned to review and revise their operator training program for the Gland Seal System.

Because this violation was of very low safety significance (Green) and was entered into the licensee's CAP as IR 1642409, this violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000265/2014003-04, "Failure to Operate the Gland Seal System as Designed")**.

.2 <u>Review of Actions Associated with Downpower Due to Unit 2 Main Power Transformer Pressure Relief Device Lifting</u>

Per IP 71153, the inspectors performed an evaluation of degraded conditions for plant status and mitigating actions related to the event that occurred on May 12, 2014. The inspectors observed operations performance during the event and the licensee's follow up and corrective actions to recover from the event. The inspectors' review was focused on the sequence of events leading up to this issue and maintenance performed on MPT-2 prior to this issue. Documents reviewed are listed in the Attachment to this report.

On May 12, 2014, the operators received the Main Transformer 2 trouble alarm with indications that the MPT-2 pressure relief device (PRD) actuated. Field observations confirmed the actuation of MPT-2 PRD and that the PRD was actively relieving oil. The operators implemented a power reduction per the Reactor Power Operations procedure in order to reseat the PRD. The licensee reduced Unit 2 power to approximately 80 percent to reseat the PRD. The PRD reseated after approximately 20 gallons of oil was vented.

The licensee determined, through their root cause evaluation, the cause of the PRD actuation was a high oil level in MPT-2 in conjunction with higher oil temperatures due to full power operations. As a part of their root cause evaluation, a review of the sequence of events leading up to this issue was conducted.

The corrective actions for this issue included a review of the oil level after this event occurred. The licensee determined that the oil level was too high for continued full power operations and drained 200 gallons of oil from the COPS tank prior to returning to full power operations on May 13, 2014.

The findings associated with this event are documented below.

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

b. <u>Findings</u>:

<u>Failure to Follow Vendor Requirements Led to Fast Downpower</u>

<u>Introduction</u>: A finding of very low safety significance (Green) was self-revealed when the licensee failed to re-establish oil level in accordance with vendor requirements in the MPT-2 COPS tank after repairs were performed on the MPT-2 Cooler Group #4 upper isolation valve. Specifically, on May 12, 2014, the MPT-2 PRD actuated because of a

high oil level in conjunction with higher temperature at full power operations. This resulted in operators reducing Unit 2 power to approximately 79 percent to reseat the PRD after approximately 20 gallons of oil was vented.

Description: During the Q2R22 refueling outage, maintenance was performed on the MPT-2 Cooler Group #4 upper isolation valve which required partially draining oil from the COPS tank. For this maintenance activity, two vendors were brought in to perform and provide oversight for the work. On April 10, 2014, oil from the MPT-2 COPS tank was drained into an oil tanker already containing approximately 300 gallons of make-up oil. The vendor providing oversight for the draining did not document the quantity of oil being removed.

Upon completion of the maintenance, MPT-2 was refilled using the oil from the tanker. The vendor providing oversight for the re-filling used the COPS tank level gauge to obtain the desired oil level. After all oil from the tanker was added to the COPS tank, the vendor determined additional oil needed to be added and 165 gallons of oil was added.

On May 12, 2014, the operators received the Main Transformer 2 trouble alarm with indications that the MPT-2 PRD actuated. Field observations confirmed the actuation of MPT-2 PRD. The operators implemented a power reduction per the Reactor Power Operations procedure in order to reseat the PRD. The licensee reduced Unit 2 power to approximately 80 percent to reseat the PRD after approximately 20 gallons of oil was vented.

According to the licensee's apparent cause report, the cause of the PRD actuation was the higher oil level in conjunction with higher oil temperatures at full power operations. The licensee relied heavily on the vendor's knowledge to assist with directing the maintenance and the vendor did not use any technical documentation to arrive at conclusions as to how the drain and fill process should have been executed. The licensee reviewed the remaining oil level and determined that 200 gallons of oil should be drained from the MPT-2 COPS tank prior to returning to full power operation.

Analysis: The inspectors determined that the licensee's failure to follow vendor manual requirements for filling MPT-2 with oil was a performance deficiency. Specifically, Instruction Manual No. 1336-A, "Siemens Vendor Manual for 3-Phase GSU Transformer," Section 5.7.3, describes requirements to determine oil fill level based on reference oil temperature. The inspectors determined that following the maintenance on MPT-2 Cooler Group #4 upper isolation valve, the licensee failed to follow the requirements of the vendor manual when filling the transformer with oil.

The performance deficiency was determined to be more than minor, and a finding, in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Initiating Events Cornerstone Attribute of Procedure Quality and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability. Specifically, the overfilling of MPT-2 caused the PRD to actuate once the plant was at full power, and on May 12, 2014, the licensee was forced to conduct a fast downpower and lowered reactor power by approximately 20 percent.

The inspectors determined the finding could be evaluated using the SDP in accordance with IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power" Exhibit 1, dated June 19, 2012. The inspectors reviewed the Initiating Events

Screening Questions in Appendix A, Exhibit 1 and answered “No” to all questions. As a result, the finding was determined to be very low safety significance (Green).

This finding has a cross-cutting aspect of field presence in the area of human performance for failing to ensure supervisory and management oversight of work activities, including contractors and supplemental personnel. Specifically, oversight of vendor activities during re-filling of the COPS tank failed to ensure that vendor guidance was used (H.2).

Enforcement: This finding did not involve a violation of regulatory requirements because the systems involved were not safety-related. The event was captured in the licensee’s CAP as IR 1659110. **(FIN 05000254/2014003-05, “Failure to Follow Vendor Requirements Led to Fast Downpower”)**.

.3 (Closed) LER 05000265/2014-001-00: Control Rod Drive Hydraulic Control Unit (HCU) Scram Inlet Isolation Valve Pressure Boundary Leak

On March 31, 2014, at 1:02 p.m., the licensee identified a through-wall valve body leak on the CRD HCU Scram Insert Isolation Valve, 2-0305-101-18-27. The valve was declared inoperable, and TS Limiting Condition for Operation 3.4.4, “Reactor Coolant System Operational Leakage,” Condition ‘C’ was entered and the unit was shut down to comply with the Action Statement. The licensee completed all actions in accordance with the TS, and replaced the scram insert isolation valve. The licensee determined the cause of the failure was due to “an inherent manufacturing defect that eventually propagated to the valve surface following years of pressure and temperature cycles that the system normally experiences.” The inspectors determined the licensee’s corrective actions for this event were appropriate.

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

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

4OA5 Other Activities

.1 Temporary Instruction (TI) 2515/189: Inspection to Determine Compliance of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a Regulatory Requirements for In-service Examination and Testing of Snubbers

a. Inspection Scope

The inspectors conducted an inspection and review of the Quad Cities Snubber Program in accordance with TI 2515/189 to verify that the program was in compliance with the requirements of Title 10 of the *Code of Federal Regulations* 50.55a, as discussed in Regulatory Information Summary (RIS) 2010-06, “In-service Inspection and Testing of Dynamic Restraints (Snubbers).” The inspectors reviewed the licensee’s response to RIS 2010-06 and verified the actions taken were appropriate.

The inspectors selected a sample of 12 snubbers based on risk-informed insights, performance history, plant conditions, and accessibility. For the selected snubbers, the inspectors reviewed a portion of the most recent in-service visual examination records and functional test records during the current 10-yr ISI interval, and then performed a walkdown of selected snubbers for independent verification. The inspectors also observed in field visual examination of snubbers. The inspector verified that the personnel performing the tasks were qualified. The inspectors also observed two in-process bench tests of the selected snubbers and verified that the test parameters met the acceptance criteria specified in the test procedure. The inspectors reviewed the process for snubber service life monitoring at the plant and determined that the selected snubbers were being monitored and maintained. The inspectors also reviewed a sample of CAP reports identified during the inspection and testing of snubbers and verified that issues were properly evaluated and entered into the CAP for resolution.

The licensee's Snubber Inservice Examination and Testing Program was inspected in accordance with Section 03.02 of the TI and responses to specific questions found in Attachment 1 of TI 2515/189 were submitted to the NRC headquarters staff and included as Attachment 2 to this inspection report.

b. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 9, 2014, the inspectors presented the inspection results to Mr. S. Darin, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The results of the TI-2515/189 inspection were presented to the Site Engineering Director, Mr. K. Ohr, and other members of the licensee's staff on April 9, 2014. The inspectors asked the licensee whether any materials examined during the inspection are considered proprietary. It was agreed that all paper copies of these proprietary documents would be shredded, and all electronic files of these proprietary documents would be deleted.

- The results of the inservice inspection with the Site Engineering Director, Mr. K. Ohr, on April 11, 2014.

- The inspection results for the areas of radiological hazard assessment and exposure controls and occupational ALARA planning and controls with Mr. S. Darin, Site Vice President, on April 18, 2014.

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

4OA7 Licensee-Identified Violations

The inspectors reviewed a licensee-identified violation of NRC requirements of very low safety significance (Green), which met the criteria of the NRC Enforcement Policy in accordance with Section 2.3.2., for being dispositioned as a NCV.

Technical Specification S 5.7.2a, High Radiation Area, states, “Areas accessible to personnel with radiation levels greater than 1000 millirem per hour at 12 inches from the radiation source shall require that doors shall be locked to prevent unauthorized entry.” Contrary to the above, on March 11, 2014, during routine Locked High Radiation Area barrier surveillance, a radiation protection technician was able to open the 1A steam jet air ejector room door, an area with radiation levels greater than 1000 millirem per hour at 12 inches. This issue was of very low safety significance because the door was equipped with a tamper seal that was intact, indicating no entry was made prior to this surveillance. The noncompliance was entered into the licensee’s CAP as IR 1632009.

In addition, Nuclear Energy Institute 99-02, Revision 7, gives a specific example of occurrences that are not counted as Occupational Radiation Safety Performance Indicators. “Occurrences that are not counted include: Occurrences associated with isolated equipment failures, for example failure of a lock when a barrier is checked or tested.”

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

<u>Licensee</u>

S. Darin, Site Vice President
K. O'Shea, Plant Manager
W. Beck, Regulatory Assurance Manager
M. DeVault, Training Director
H. Dodd, Site Maintenance Director
M. Kaufman, Outage Manager
D. Kimler, Operations Director
R. Luebbe, Regulatory Assurance
S. Piepenbrink, Security Manager
G. Powell, Radiation Protection Technical Support Manager
A. Scott, Work Management Director
B. Stedman, Senior Engineering Manager
B. Wake, Shift Operations Superintendent
T. Wojick, Nuclear Oversight Manager
J. Wooldridge, Chemistry Manager

<u>Nuclear Regulatory Commission</u>

C. Lipa, Chief, Reactor Projects Branch 1

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000265/2014003-01	NCV	Seismic Scaffold in Contact with Safety-Related Equipment (Section 71111.20)
05000254/2014003-02	NCV	Post Maintenance Test Fails to Ensure Battery Charger can Perform Function (Section 4OA2.03)
05000265/2014003-03	NCV	Failure to Meet Design Requirement for Safety-Related Cables in 'D' Heater Bay (Section 4OA3.01)
05000265/2014003-04	NCV	Failure to Operate the Gland Seal System as Designed (Section 4OA3.01)
05000254/2014003-05	FIN	Failure to Follow Vendor Requirements Led to Fast Downpower (Section 4OA3.02)

Closed

05000265/2014003-01	NCV	Seismic Scaffold in Contact with Safety-Related Equipment (Section 1R20.1)
05000254/2014003-02	NCV	Post Maintenance Test Fails to Ensure Battery Charger can Perform Function (Section 4OA2.3)
05000265/2014003-03	NCV	Failure to Meet Design Requirement for Safety-Related Cables in 'D' Heater Bay (Section 4OA3.1)
05000265/2014003-04	NCV	Failure to Operate the Gland Seal System as Designed (Section 4OA3.1)
05000254/2014003-05	FIN	Failure to Follow Vendor Requirements Led to Fast Downpower (Section 4OA3.2)
05000265/2014-002-00	LER	Alert Declared Due to Fire in Unit 2 Turbine Building (Section 4OA3.1)
05000265/2014-001-00	LER	Control Rod Drive Hydraulic Control Unit Scram Inlet Isolation Valve Pressure Boundary Leak (Section 4OA3.3)

Discussed

Temporary Instruction 2515/189	TI	Inspection to Determine Compliance of Dynamic Restraint (Snubber) Program with 10 CFR 50.55a Regulatory Requirements for In-service Examination and Testing of Snubbers (Section 4OA5)

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 14
- Letter from Scott Darin, Site VP Quad Cities Generating Station to Tim Hanley, Senior VP West Nuclear Operations; Subject: Quad Cities Station Certification of 2014 Summer Readiness; May 14, 2014
- Management Directed Assessment Report Quad Cities Summer Readiness NOSMDA-QC-14-04; April 3, 2014
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- IR 01672981: Main Generator and Digital Fault Recorder Alarms; June 19, 2014
- IR 01673344: MPT 1 Loss of Oil Flow Alarm; June 19, 2014
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- OP-AA-108-107-1001: Station Response to Grid Capacity Condition; Revision 4
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- IR 01366914: U2 SBO DG Room Exhaust Fan Damper Open; June 15, 2012
- IR 01390878: U2SBO Fan 2-5790-6003 Will Not Operate; July 19, 2012
- IR 01392590: TOLS for U2 SBO Exhaust Fan 2-5790-6003 are Degraded; July 24, 2012
- IR 01648757: NRC ID – Cracked Face TI 2-6620-145A SBO Lube Oil Cooler; April 17, 2014
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- QOM 1/2-6600-01: Unit 1/2 Diesel Generator Valve Checklist; Revision 16
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- EC 392068: Core Spray ECCS Keep Fill Stop Valve 1-1402-65A&B Reorientation
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- IR 01343370: Core Spray Pipe Hanger Bolts Less Than Flush to Top of Nut; March 20, 2012
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- IR 01343935: Q2R21 Core Spray 12" Pipe Lamination; March 21, 2012
- IR 01346578: 2A/2B Core Spray CCST Suction Line Hanger Bolt Tightness; March 28, 2012
- IR 01646019: NRC ISI Inspector Question on ER-AA-335-004, UT Procedure; April 11, 2014
- IR 01470365: Unit – 2 RHRSW VT-3 Inspection Recordable Indications; February 1, 2013

- IR 01347632: PSU Coverage Less Than 90% for ISI Component 0200-W-178; March 29, 2012
- ER-AA-335-002: Liquid Penetrant (PT) Examination; Revision 6
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- IR 01492021: U-1/2 250 Vdc Charger Failed to Start; March 25, 2013
- IR 01498508: 2D Corrosion Noted on U2 250 Vdc Safety Related Battery; April 6, 2013
- IR 01503674: Unit 2 250 Vdc Ground; April 18, 2013
- IR 01559159: U2 250 Vdc Charger dc Breaker Tripped During Load Test; September 16, 2013
- QOP 6900-04: 250 Vdc Ground Detection Unit 1; Revision 21
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- IR 01661623: 1D3 FWH ES Inlet MOV Walkdown During Next U1 Derate; May 19, 2014
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- IR 01635616: LL – Review SBGT PM Performance; March 29, 2014
- IR 01478320: ½ 'B' SBGT AO 0-7510-B in ALERT Range for Stroke Time February 21, 2014
- IR 01664739: Level III Ground on the Unit 1 125 Vdc Battery System; May 27, 2014
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- IR 01665621: U1 125 Vdc Ground – Update; May 29, 2014
- IR 01644595: U1 125 Vdc Grounds Isolated – ATR Entered; April 8, 2014
- IR 01655594: Extent of Condition Inspection of Riser R270 Cables; May 4, 2014
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- IR 01651581: IEMA Rep Scaffold Question; April 25, 2014
- IR 01639365: IEMA: Scaffold Potentially Contacting SR Equipment; March 27, 2014
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- IR 01644669: Q2R22 MSIV 2A High Seat Leakage Step Jump; April 8, 2014
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- IR 01661876: NRC Identified HPCI LP Pump Outboard Bearing High Oil Level; May 19, 2014
- IR 01657304: U2 Drywell Equipment Drain Sump High Temp; May 8, 2014
- IR 01658983: Rise in U2 DWFD Sump Leakage from Q2C22 to Q2C23; May 12, 2014
- IR 01660270: Need a WR to Address Unit 2 Drywell Leakage; May 15, 2014
- IR 01667491: Alarm 902-4 Panel B17 (DWEDS High Level Alarm); June 3, 2014
- IR 01667966: U2 DWEDS High Level Alarm; June 4, 2014
- IR 01674935: 2A DWEDS Pump Breaker Tripped; June 25, 2014
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- QCOS 1600-07: Reactor Coolant System Leakage in the Drywell (DWFDS and DWEDS Available); Revision 34
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- RCR 1642409: Main Turbine Steam Seal System Steam Leak and Subsequent Fire in Cable Tray Due to Inadequate Cable Routing, May 16, 2014
- IR 01568455: U-1 250 Vdc Battery Charger Output Float Voltage Degrading; October 6, 2013
- IR 01631541: Fluctuating Voltage on U1 250 Vdc System
- Apparent Cause Investigation Report (Equipment) 1631541-04; May 8, 2014
- IR 01644355: 1B RFP O/B Vent Line is Leaking; April 8, 2014

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- 4E-1328: Single Line Diagram Emergency Power System; Revision F
- 4E-2066A: Electrical Installation Turbine Building Mezzanine Floor Plan El. 611'-6" Southeast; April 2, 2005
- 4E-2676B: Wiring and Schematic Diagram Turb Bldg ESS Service 480V MCC 28-2 Part 2; Sheet F
- 4E-2901J: Cable Tabulation Cables 20400 to 20449; March 10, 2005
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- Alert Root Cause Briefing; April 2, 2014
- IR 01648232: PSU Found a Burnt Transformer MCC 26-3 G1; April 16, 2014
- IR 01648351: Circuit Breakers Exposed to X-Fmer Fire to be Replaced; April 16, 2014
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- IR 01648366: Cables for MOV May Need Inspected for Brittleness From Heat; April 16, 2014
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- IR 01648476: FAS Alarm for U1 Main Turbine Bearings; April 17, 2014
- IR 01655594: Extent of Condition Inspection of Riser R270 Cables; May 4, 2014
- IR 01655610: Root Cause IR 1642409 Extent of Condition Cable Inspections; May 4, 2014
- IR 0101562: Quad Cities Station License Renewal Commitments; August 27, 2004
- IR 01642317: Level Three Hard Ground on U1 125 Vdc System; April 2, 2014
- IR 01644353: Electrical Penetrations Above Tray 777T – Sparking Observed; April 8, 2014
- IR 0441896: Butyl Rubber Insulated Cables Located in D-Heater Bay; January 13, 2006
- IR 0622753: EQ Program Indicator is Yellow for 1st Qtr of 2007; May 15, 2007

- IR 0705969: Replace Identified Butyl Rubber Cables; May 15, 2008
- IR 0747735: Various Cables in Trays 847T, 848B and 848T are Degraded; September 30, 2010
- EC 384857: (10) – EQ 2011, Update EQ Binder EQ-04Q to Reflect Cable 13105 Qualified Life, Revision 0
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- IR 1642409: Investigation Charter, April 2, 2014
- LN-6800: ESS Service/Instrument Bus System; March 14, 2012
- MA-AA-723-500: Inspection of Non-EQ Cables and Connection for Managing Adverse Localized Environments; Revision 6
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- QCEM 0700-11: Insulation Resistance Testing; Revision 13
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- Quad Cities Station Aging Management Program Results Book - B.1.33: Electrical Cables Not Subject to EQ Requirements; June 12, 2012
- RCR 1642409-04: Quad Cities Alert Root Cause Report; Revision 0
- Review of License Renewal Aging Management Programs for Electrical Cables; April 16, 2014
- Significant Events Log (SEL); April 1 – April 3, 2014
- U2 SER Data 8 hr Prior Fire 02Apr2014; April 4, 2014
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- WO 01725773: Install DG CW Pump Control Cable Per EC 397693; April 7, 2014
- WO 01728908: Q2R22 PSU EDG Cables 28472, 28476, 28477 Need Testing; April 11, 2014
- WO 1548970: Recirc System Power Operated Valve Test (IST); April 3, 2014
- WO 1725765: Install RB Vents Panel 2252-24X 125VDC Feed Per TMOD 397692; April 8, 2014
- QOA 900-8 C-11: 901-8 (902-8) Row C Annunciator Procedures; Revision 4
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- WO 01528845: T2 Cooler #4 Upper Valve Leak Repair; January 24, 2014
- Instruction Manual No. 1336-A: Siemens Vendor Manual for 3-Phase GSU Transformer
- Letter from Christoph Kerschenbauer, Project Manager Siemens Transformers to Quad Cities Station; Subject: Quad Cities Unit 2 Transformer Work Order 66736, Oil Spill / STW Statement Regarding the Current Oil Level; May 24, 2014

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- IR 01659104: U2 MPT Oil Leak; May 12, 2014
- IR 01659110: MPT-2 Oil Pressure Relief Valve Lifted; May 12, 2014

Section 4OA5

- EC 388050: Evaluation of Temporary Snubber Removal for System Impact; Revision 1
- 50.59 Screening No. QC-S-2013-0093: Update TRM Section 3.7.h (Snubbers) to Include Immediate Operabilty Assessment of Supported System; Revision 0
- NOSA-QDC-12-08: Inservice Inspection, Inservice Testing, and Appendix J Audit Report; September 26, 2012
- Procedure No. ER-AA-330-004: Visual Examination of Snubbers; Revision 9
- Procedure No. ER-AA-330-010: Snubber Functional Testing; Revision 5
- Procedure No. ER-AA-330-011: Snubber Service Lift Monitoring; Revision 6
- Procedure No. ER-QC-330-004: Visual Examination of Safety Related Snubbers; Revision 4
- Procedure No. ER-QC-330-010: Snubber Functional Testing Methods and Performance Criteria; Revision 6
- Procedure No. ER-AA-335-016: VT-3 Examination of Component Supports, Attachments and Interiors of Reactor Vessels; Revision 9
- Report No. 14-VT3-070: VT-3 of of Snubber Component No. 2-1025-98; March 31, 2014
- Report No. 14-VT3-074: VT-3 of of Snubber Component No. 2-2310-105; March 31, 2014
- Report No. 14-VT3-076: VT-3 of of Snubber Component No. 2-1015-A124; March 31, 2014
- Report No. 14-VT3-078: VT-3 of of Snubber Component No. 2-2306-133; April 1, 2014
- Report No. 14-VT3-082: VT-3 of of Snubber Component No. 2-2306-143; April 1, 2014
- Report No. 14-VT3-068: VT-3 of of Snubber Component No. 2-1025-96; April 3, 2014
- Report No. 14-VT3-052: VT-3 of of Snubber Component No. 2-3019-E64; April 8, 2014
- Root Cause No. A/R 758609-02: Ineffective Implementation of the Snubber Service Life Monitoring Program Resulted in Higher Than Normal Failures During Q2R19; May 22, 2008
- Self-Assessment No. 1598605-04: Check-In for pre-NRC inspection on Inservice Inspection (ISI); February 7, 2014
- Technical Requirements Manual Section 3.7.h: Snubbers; Revision QC-TRM-12-002
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- Work Order No. 1337003: Snubber Visual Inspection-Accessible; March 19, 2012
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- Work Order No. 1333255: U2 Snubber Funct test/Documenting Service Life Monitoring; March 27, 2012
- Work Order Testing No. 1548085-01: Functional Test of Snubber 2-105; March 31, 2014
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- IR 01078841: RIS 2010-06 ISI/IST Requirements of Dynamic Restraints; June 9, 2010
- IR 01192121: Grouted Area Around Torus Snubber Footing Requires Painting; March 25, 2011
- IR 01336369: Technical Requirements Manual Section 3.7.H-Snubbers; March 5, 2012
- IR 01625393: Administrative Error Found in UFSAR Section 6.6.1; February 24, 2014

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CCDP	Conditional Core Damage Probability
CLERP	Conditional Large Early Release Probability
COPS	Conservator Oil Preservation System
CPT	Control Power Transformer
EAL	Emergency Action Level
EC	Engineering Change
EQ	Environmental Qualification
ESS	Essential Service
FAS	Fire Alarm System
HCU	Hydraulic Control Unit
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
LERF	Large Early Release Frequency
MCC	Motor Control Center
MPT	Main Power Transformer
MSIV	Main Steam Isolation Valve
MT	Magnetic Particle
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
OSP	Outage Safety Plan
PARS	Publicly Available Records System
PI	Performance Indicator
PRD	Pressure Relief Device
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RFO	Refueling Outage
RHR	Residual Heat Removal
RWP	Radiation Work Permit
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic
WO	Work Order

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Sincerely,

/RA/

Christine Lipa, Chief
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