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

July 31, 2009

Mr. Charles G. Pardee
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Officer (CNO), Exelon Nuclear
4300 Winfield Road
Warrenville IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000254/2009003; 05000265/2009003

Dear Mr. Pardee:

On June 30, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. The enclosed report documents the inspection results, which were discussed on July 9, 2009, with Mr. T. Tulon and other members of your staff.

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

Based on the results of this inspection, one NRC-identified and three self-revealed findings of very low safety significance were identified. The findings involved violations of NRC requirements. However, because of their very low safety significance, and because the issues were entered into your corrective action program, the NRC is treating the issues as Non-Cited Violations (NCVs) in accordance with Section VI.A.1 of the NRC Enforcement Policy.

If you contest the subject or severity of a NCV, 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. If you disagree with the characterization of 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 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; and the Resident Inspector Office at the Quad Cities Nuclear Power Station. The information you provide will be considered in accordance with Inspection Manual Chapter 0305.

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

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000254/2009003; 05000265/2009003
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Quad Cities Nuclear Power Station
Plant Manager - Quad Cities Nuclear Power Station
Manager Regulatory Assurance -
Quad Cities Nuclear Power Station
Senior Vice President - Midwest Operations
Senior Vice President - Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Licensing and Regulatory Affairs
Manager Licensing - Clinton, Dresden and Quad Cities
Jeff Gust, VP Energy Supply Management, MidAmerican Energy
Associate General Counsel
Document Control Desk - Licensing
Assistant Attorney General
J. Klinger, State Liaison Officer,
Illinois Emergency Management Agency
M. Rasmusson, Chief, Bureau of Radiological Health,
Iowa Department of Public Health
Chairman, Illinois Commerce Commission
Chief Radiological Emergency Preparedness Section,
Dept. Of Homeland Security

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Chairman, Illinois Commerce Commission
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Letter to C. Pardee from M. Ring dated July 31, 2009

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000254/2009003; 05000265/2009003

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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:	05000254/2009003 and 05000265/2009003
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, IL
Dates:	April 1 through June 30, 2009
Inspectors:	J. McGhee, Senior Resident Inspector B. Cushman, Resident Inspector E. Coffman, Reactor Engineer W. Slawinski, Senior Radiation Protection Inspector D. Jones, Reactor Inspector, DRS C. Mathews, Illinois Emergency Management Agency
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000254/2009003, 05000265/2009003; 04/01/09 - 06/30/09; Quad Cities Nuclear Power Station, Units 1 & 2; Plant Modification, Emergency Preparedness, and Other Activities.

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

A. NRC-Identified and Self-Revealed Findings

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and associated NCV were identified by NRC inspectors for an inadequate procedure, QCOA 0010-09, "Earthquake." This procedure did not direct a shutdown in response to an earthquake event in excess of the operating basis earthquake threshold. Title 10 CFR 100 Appendix A, Section V(a)(2) states, "If vibratory ground motion exceeding that of the Operating Basis Earthquake occurs, shutdown of the nuclear power plant will be required." Upon discovery, the licensee implemented immediate changes to QCOA 0010-09.

  This finding was more than minor because this performance deficiency challenged the Reactor Safety - Mitigating Systems Cornerstone attribute of procedure quality. The inspectors performed a Phase 1 SDP screening using IMC 0609, Attachment 4, Table 4a for the Mitigating Systems Cornerstone. All questions were answered "no" and the issue screened as Green, or very low safety significance. The inspectors determined that this finding did not have a cross-cutting aspect because this procedure has been in place since initial operation and this deficiency was determined to be a latent issue not readily identified through the procedure revision process. (Section 1EP6)

- Green. A finding of very low safety significance and a NCV of Quad Cities Unit 2 Renewed License No. DPR-30 condition 3.B were self-revealed on April 10, 2009, when a previously unidentified blown fuse on the 1/2 emergency diesel generator (EDG) control power transfer circuit resulted in failure of the power supply for the associated diesel generator cooling water pump to transfer from Unit 1 to Unit 2. The fuse had apparently failed on March 25, 2009, when operators attempted to replace a burned out light bulb resulting in the diesel being inoperable for Unit 2 for 17 days. Although operators had indications that a circuit problem existed, timely actions were not initiated to ensure the unit continued to operate in accordance with Technical Specifications. Immediate corrective actions were accomplished on April 11, 2009, with replacement of the fuse and verification of circuit operability. Inspectors determined this finding to be cross-cutting in the area of Problem Identification and Resolution for the corrective action component because station personnel failed to investigate the non-conforming condition as directed by station procedures to adequately assess the impact on system operability and did not meet procedural requirements for evaluating operability (P.1(c)).

The inspectors determined the finding was more than minor because the finding is associated with the Mitigating Systems Cornerstone attribute of equipment reliability and affected the cornerstone objective by impacting availability, reliability and capability of the Unit 2 emergency electrical supplies. Specifically, allowing the non-conforming condition on the 1/2 EDG to linger while performing maintenance activities on the Unit 2 EDG challenged the availability of emergency AC power to Unit 2. The inspectors reviewed this finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspections Findings for At-Power Situations." The postulated accident where the 1/2 EDG would have failed its safety function is a loss of offsite power to both units followed by a loss of coolant accident on Unit 2. The Significance Determination Phase 2 performed by the residents and validated by the regional senior risk analyst showed risk significance much lower than the $1x10^{-6}$ threshold and therefore Green. (Section 4OA2)

- Green. A finding of very low safety significance and NCV of 10 CFR 50.65(a)(4) were self-revealed on May 11, 2009, when the licensee staff failed to manage water level in the spent fuel pool and associated skimmer surge tanks resulting in the Unit 2 fuel pool cooling pumps tripping off while removing the Scorpion platform from the Unit 1 reactor cavity. Immediate corrective actions for this event included refilling the skimmer surge tank and restarting the fuel pool cooling pumps to restore alternate decay heat removal. The inspectors determined that the failure to take adequate action to manage the risk associated with a maintenance activity with a potential to affect a key shutdown safety function was a performance deficiency and a finding. Inspectors determined that the finding was cross-cutting in the area of Human Performance – Work Control for failure to coordinate work activities by incorporating actions to adequately address the need for work groups to communicate, coordinate and cooperate with each other during activities in which interdepartmental coordination is necessary to assure plant and human performance (H.3(b)).

  The inspectors determined the finding was more than minor because the failure to implement the management actions resulted in the critical safety function being degraded and the issue is associated with 10 CFR 50.65(a)(4) risk management. The inspectors performed a Phase 1 SDP evaluation and determined that the issue is Green because the Unit 1 pumps remained running with no issues during the event and plant operators were able to recover the Unit 2 cooling pumps before any discernable change in temperature occurred (answer to all questions of IMC 0609, Attachment 4, Table 4a, Mitigating Systems Cornerstone and Barrier Cornerstone were "no" and the issue screened as Green). Since the finding concerned risk management actions, the inspectors verified the finding was Green using IMC 0609, Appendix K flowcharts and validated that there was no change in risk thresholds as a result of the event. (Section 4OA3)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance and associated NCV of 10 CFR 50, Appendix B, Criterion V were self-revealed during the performance of the Unit 1 traversing incore probe (TIP) modification testing on March 27, 2009. During modification testing, the #2 TIP retracted past the shielded position into the reactor building as a result of failure of test personnel to follow the test procedure. The control room received a, "Rx Bldg Hi Radiation" alarm from the local area radiation monitor. Radiation Protection personnel were on scene to evacuate personnel, track dose rates and to set up boundaries to prevent entry. There were no over exposures and no danger to the health and safety of other radiological workers as a result of this event. The inspectors determined that this finding has a cross-cutting aspect in the area of Human Performance, Work Practice - Expectations. The test coordinator position did not have a qualification program or documented management expectations for procedure adherence (H.4(b)).

The inspectors determined that the failure of the test coordinator and instrument maintenance technicians to follow an approved procedure, TIC-2306, "Automated TIP Control Unit (ATCU) Modification Test," was a performance deficiency and a finding. This finding was more than minor because if left uncorrected, this performance deficiency has the potential to lead to a more significant safety concern. The inspectors performed a Phase 1 SDP screening. Inspection Manual Chapter 0609, Attachment 4, Table 4a, Mitigating Systems Cornerstone questions were all answered "no." Therefore the issue screened as Green, or very low safety significance. (Section 1R18)

B. <u>Licensee-Identified Violations</u>

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1

Unit 1 operated at full electrical output of 912 megawatts electric (MWe) from April 1 until beginning power coast down to the refueling outage on April 14. Power reduction for refueling outage Q1R20 began at 7:00 p.m. on April 26. The unit restarted from the refueling outage on May 22 at 5:21 p.m. During reactor core isolation cooling (RCIC) system testing after reaching full reactor pressure, a containment isolation valve was determined to have failed and plant staff determined that a unit shutdown would be required in order to troubleshoot, repair, and retest the valve. Operators commenced a unit shutdown from 19 percent thermal power at 12:00 a.m. on the morning of May 25 and began forced outage, Q1F59. Startup from the forced outage began on May 30 at 02:25 a.m. and electrical output was restored to 912 MWe on June 1 at 07:00 a.m. Thermal power was subsequently raised to 100 percent on June 3 at 11:40 a.m. Power remained at that power level for the remainder of the reporting period with the exception of planned power reductions for routine surveillances and control rod maneuvers.

Unit 2

Unit 2 operated at or near full electrical output of 912 MWe from April 1 until April 16 at 9:00 p.m. when a downpower was conducted to 250 MWe for main condenser leak check maintenance, rod pattern adjustment, and turbine testing. The unit returned to 912 MWe on April 19 at 7:20 p.m. and operated there until April 22 at 11:40 a.m. when operators raised thermal power to 100 percent after final electrical power restrictions were removed. The unit remained at 100 percent thermal power for the remainder of the reporting period with the exception of planned power reductions for routine surveillances and control rod maneuvers.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate Alternating Current 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 verified that procedural requirements in place at the time the last sample was performed for this inspection procedure remained in place and all revisions were reviewed to verify communications protocols between the transmission system operator (TSO) and the plant continued to address appropriate information exchange when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- the coordination between the TSO and the plant during off-normal or emergency events;
- the explanations for the events;

- the estimates of when the offsite power system would be returned to a normal state; and
- the notifications from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures continued to address 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 corrective action program (CAP) items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

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

b. Findings

No findings of significance 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. Specific documents reviewed during this inspection are listed in the Attachment to this report. The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures. The inspectors' reviews focused specifically on the following plant systems:

- Unit 1 and Unit 2 Torus (Suppression Pool) Cooling Systems, and
- Unit 1 and Unit 2 Isophase Bus Duct Cooling Systems.

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

b. Findings

No findings of significance 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:

- 1/2 Emergency Diesel Generator,
- Unit 1 250 Vdc System,
- Unit 2 250 Vdc System,
- Unit 1 125 Vdc System, and
- Unit 2 125 Vdc System.

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

These activities constituted five partial system walkdown samples as defined in IP 71111.04-05.

b. Findings

No findings of significance 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:

- Unit 1 Turbine Bldg. El. 595’-0”, LP Heater Bay Fire Zone 8.2.6.B;
- Unit 1 Turbine Bldg. El. 608’-6”, LP Heater Bay (West) Fire Zone 8.2.7.B;
- Unit 1 Turbine Bldg. El. 615’-6”, ‘A’ Battery Charger Room U-1 Fire Zone 6.1.A;
- Unit 1 Turbine Bldg. El. 615’-6”, ‘B’ Battery Charger Room U-1 Fire Zone 6.1.B; and
- Unit 2 Turbine Bldg. El. 595’-0”, Safe Shutdown Makeup Pump Room Fire Zone 5.0.

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

b. Findings

No findings of significance 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 CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant area(s) 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 1 Reactor Building Basement Torus Area.

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

a. Findings

No findings of significance were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 1A residual heat removal heat exchanger to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors reviewed the licensee's observations as compared against acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on test results. Inspectors also verified that test acceptance criteria considered differences between test conditions, design conditions, and testing conditions. Documents that were reviewed for this inspection are listed in the Attachment to this report.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07-05.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08G)

From April 20, 2009, through April 23, 2009, 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 1R08.2 below constituted one inspection sample as defined in IP 71111.08-05.

.1 Piping Systems Inservice Inspection

a. Inspection Scope

The inspectors observed or reviewed records of the following nondestructive 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 Examination of the high pressure coolant injection (HPCI), pipe to reducer weld, 2306-6, Report No. Q1R20-004;
- Ultrasonic Examination of the HPCI, elbow to elbow weld, 2325-9, Report No. Q1R20-003;
- Ultrasonic Examination of the HPCI, reducer to pipe weld, 2306-7, Report No. Q1R20-005;
- Ultrasonic Examination of the HPCI, elbow to pipe weld, 2325-10, Report No. Q1R20-001;
- Ultrasonic Examination of the HPCI, pipe to elbow weld, 2325-11, Report No. Q1R20-002; and
- Visual Examination (VT) of residual heat removal system component support 1009B-W-211, Report No. Q1R20-014.

During the prior outage non-destructive surface and volumetric examinations, the licensee did not identify any relevant/recordable indications. Therefore, no NRC review was completed for this inspection procedure attribute.

The licensee had not performed pressure boundary welding since the beginning of the preceding outage for Unit 1. Therefore, no NRC review was completed for this inspection procedure attribute.

b. Findings

No findings of significance were identified.

.2 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 of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On April 13, 2009, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator training crew evaluations 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.

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

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations (71111.12Q)

a. Inspection Scope

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

- Z1900: Fuel Pool Cooling and Cleanup.

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 one maintenance effectiveness sample as defined in IP 71111.12-05.

b. Findings

No findings of significance 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:

- Week of April 6 - 12, 2009: Switchyard work, Unit 1 125 Vdc battery and charger out-of-service, Unit 1 load drop, bus 23-1 under voltage testing with 1/2 emergency diesel generator unavailable to Unit 2;
- Week of April 20 - 26, 2009: Unit 2 condenser tube plugging, Unit 2 diesel generator cooling water pump replacement, switchyard work to open breakers 7-8;
- Week of April 13 - 18, 2009: Banana jack installation for 'A' standby gas treatment system, 'B' standby gas treatment system, 1/2 emergency diesel generator, Unit 2A core spray, Unit 2 emergency diesel generator, Unit 2B core spray, Unit 1 250 Vdc foam installation and Unit 2 condenser tube plugging;
- Outage schedule shutdown risk evaluations for Q1R20 week 1, April 27 - May 2, 2009: Reactor shutdown, removal of division 1 equipment, electrical distribution changes with emergent equipment issues delaying refueling activities;
- Outage schedule shutdown risk evaluation for Q1R20 Week 2, May 4 - 8, 2009: Unit 1 emergency diesel generator cooling water heat exchanger replacement, transformer 12 and bus 14 OOS, control rod drive replacement, 1/2 'B' standby gas treatment system inoperable, 'B' control room HVAC inoperable, transformer 18 replacement, GCB 8-9 work and refueling operations; and
- Emergent trip of RCIC during surveillance on May 24, 2009, containment isolation valve failures and subsequent shutdown for repair.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstone. 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.

These maintenance risk assessments and emergent work control activities constituted six samples as defined in IP 71111.13-05.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- IR 900389, Incorrect Tap Settings in Aux Power Calculation;
- IR 910091, Barometric Condenser Condensate Pump Tripped during QCOS 1300-05;
- IR 905945, Replacement Valve Not Suitable for End Use Application;

- IR 915723, Main Steam Line Break Conditions Impact Technical Requirement Manual Allowed Value Calculations for 1(2)-0263-73A(B); and
- IR 925804, 3E Relief Valve High Temperature (Approximately 290 Degrees Fahrenheit).

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations, to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also 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 five samples as defined in IP 71111.15-05.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

.1 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification(s):

- EC 372983, Lift Lead to Restore Control Rod Position Indication and Remove Nuisance Overtravel Alarm Indication.

The inspectors compared the temporary configuration changes and associated 10 CFR 50.59 screening and evaluation information 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 also compared the licensee's information to operating experience information to ensure that lessons learned from other utilities had been incorporated into the licensee's decision to implement the temporary modification. The inspectors verified the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. Lastly, the inspectors discussed the temporary modification with operating personnel to ensure that the individuals were aware of how extended operation with the temporary modification in place could impact overall plant performance. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

This inspection constituted one temporary modification sample as defined in IP 71111.18-05.

a. Findings

No findings of significance were identified.

.2 Permanent Plant Modifications

a. Inspection Scope

The following engineering design packages were reviewed and selected aspects were discussed with engineering personnel:

- EC366310, Replacement of the Reactor Recirculation Motor Generator Sets with Adjustable Speed Drives (ASDs); and
- EC 365238, Unit 1 Automated TIP Control Unit (ATCU) Installation.

These packages and related documentation were reviewed for adequacy of the associated 10 CFR 50.59 safety evaluation screening, consideration of design parameters, implementation of the modification, post-modification testing, and relevant procedures, design, and licensing documents were properly updated. The inspectors observed ongoing and completed work activities to verify that installation was consistent with the design control documents.

The adjustable speed drive modification installed electronic based controls and control panels to replace the rotating generators and scoop tube drive configuration of the existing recirculation motor generator sets. The ASD's main components consisted of multiple winding stepdown transformer, AC/DC variable AC converters, water cooling system with heat exchangers, and dual control and protective microprocessor systems with independent backup protection relays. While the voltage source to the recirculation pumps changed with this modification, the reactivity control methodology remained the same. The digital reactor recirculation control system remained the control system for recirculation pump speed, and interfaced via direct digital communication with the ASD system. There were no changes to the reactor protection system or the engineered safety feature actuation system (ESFAS) (including parameters measured, location of the measurements, setpoints, trip coincidence logic, final actuating devices or power supplies to any of these components). Thus, for any recirculation system transient or accident, RPS and ESFAS provided the same response as before the modification. The reactor recirculation pump speed, system pressure, and rate of change of flow remained the same. The maximum speed as determined by extended power uprate licensed values and reflected in the core operating limits report remained unchanged.

The Unit 1 ATCU modification removed the S. Levy computer, man-machine interface, interconnection cards, and power supplies and replaced them with five new General Electric (GE) ATCUs. The original GE flux probe monitor unit was also removed. In the new system, the ATCU included the flux signal amplification function so each of the five flux sensor cables landed directly at the ATCU for that channel. Inside each of the five drive mechanisms in the reactor building, the S. levy absolute position encoder transducer, support bracket, torque amplifier and torque transducer were removed and a new GE (Reuter-Stokes) position encoder transducer and bracket were installed. The existing traversing incore probe (TIP) system cables between the TIP components in the reactor building and panel 901-13 were reused, or abandoned in place as needed. Documents reviewed in the course of this inspection are listed in the Attachment to this report.

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

a. Findings

(1) Inadequate Procedural Adherence During Unit 1 Traversing Incore Probe Post-Maintenance Testing

Introduction: A self-revealed finding of very low safety significance (Green) was identified for failure of the test team to follow the procedure during the performance of the Unit 1 TIP modification testing.

Description: On March 27, 2009, modification testing was scheduled for the Unit 1 TIP control system. During performance of this testing, the TIP for the #2 TIP machine retracted into the reactor building, past the shielded position, onto the cable reel. The control room received a, "Rx Bldg Hi Radiation" alarm from the local area radiation monitor, and personnel were evacuated from the area. Radiation Protection was on scene to track dose rates and to set up boundaries to prevent entry. There were no over exposures and no danger to the health and safety of other radiological workers as a result of this event.

During the investigation of this event, inspectors identified that undocumented issues were present during the testing. The TIP modification test involved core top position calibrations for the new control modules. During performance of TIC-2306, "Automated TIP Control Unit (ATCU) Modification Test," the ATCU would freeze upon completion of hand cranking to the core top position. The next step directed the return of the detector to the parked position by using the TIP drive. This step was unable to be completed because the ATCU would not respond to control inputs. The test coordinator believed single steps could be performed out of sequence and made the decision to cycle power to reinitialize the ATCU. The test coordinator directed the removal of power by performing only step 6.1.2, which disconnected the power cable. Power to the ATCU was then restored by performing only step 6.3.1, which connected the power cable. No other steps were performed prior to resuming the test at step 6.3.46.

Upon completion of step 6.3.46, the detector would overshoot the park position by 7-inches. The next step, step 6.3.47, was to verify the detector stops at the parked position. The test coordinator directed the cycling of power to again reinitialize the ATCU, and the detector was returned to the parked position by using the TIP drive. Step 47 was then signed off as complete. These indications were noted for multiple channels of the #2 TIP machine.

Limitations Section 4.7 of TIC-2306, "Automated TIP Control Unit (ATCU) Modification Test," states in part that the test will be aborted if provisions of this procedure cannot address results attained, or if the procedure cannot be performed. The test coordinator made the decision to use steps of the procedure out of sequence to return the TIP system to a condition to continue testing. The justifications for continuing the test after identifying unexpected conditions were not documented and were not reviewed by supervision.

Analysis: The inspectors determined that the failure of the test coordinator and instrument maintenance technicians to follow the approved procedure, TIC-2306, "Automated TIP Control Unit (ATCU) Modification Test," was a performance deficiency and a finding. This performance deficiency challenged the Reactor Safety - Barrier Integrity Cornerstone attribute of design control for the containment barrier and was more than minor because if left uncorrected, this performance deficiency could lead to a more significant safety concern.

The inspectors performed a Phase 1 SDP screening. Inspection Manual Chapter 0609, Attachment 4, Table 4a, Containment Barrier questions were all answered "no." Therefore the issue screened as Green, or very low safety significance. The inspectors determined that this finding has a cross-cutting aspect in the area of Human Performance, Work Practice, Expectations (H.4(b)) because the licensee did not communicate clear expectations for procedure execution and compliance by test coordinators. The test coordinator felt at the time his decisions were appropriate to safely complete the modification testing. The lack of documented expectations and the failure to communicate expectations to test coordinators was identified as the root cause in the licensee's root cause analysis report (IR 901970-02).

Enforcement: Title 10 CFR 50, Appendix B, Criterion V states in part that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures.

Contrary to the above, TIC-2306, "Automated TIP Control Unit (ATCU) Modification Test," was not performed as written by the test coordinator and instrument maintenance technicians during post-modification acceptance testing on March 27, 2009. Corrective actions included formal development and communication of management expectations, including procedure compliance and supervisor engagement, for personnel while fulfilling a role as a test coordinator. Licensee management scheduled an increased oversight role of evolutions involving test coordinators until licensee management was satisfied that test coordinators fully understand the expectations of their position. The licensee also performed an extent of condition review for other testing activities such as logic tests, surveillance tests and other departmental modification tests.

Because this violation is of very low safety significance, and because the issue was entered into the CAP as Issue Report 901970, this issue is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy
(NCV 05000254/2009003-01).

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

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

- Unit 1 'B' MSIV local leak rate test and valve timing stroke after maintenance,
- Retest of the 1/2 ‘B’ Control Room Ventilation Chiller following compressor replacement due to high vibration amplitude,
- Unit 1B Recirculation Pump Discharge MOV (MOV-1001-5B) motor replacement,
- Unit 1B Core Spray Discharge Stop Check Valve maintenance, and
- Unit 1 LPCI Inboard Injection Valve (MOV-1001-29A) VOTES testing and limit switch setpoint verification.

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 five post-maintenance testing samples as defined in IP 71111.19-05.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

.1 Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the Shutdown Safety Management Plan and contingency plans for the Unit 1 refueling outage (Q1R20), conducted April 27 - May 24, 2009, 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 Q1R20 the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment to this report.

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the outage safety plan 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 outage safety plan (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.
- 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.
- Licensee identification and resolution of problems related to Q1R20 activities.

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

b. Findings

No findings of significance were identified.

.2 Other Outage Activities

a. Inspection Scope

The inspectors evaluated outage activities for a Unit 1 forced outage (Q1F59) that began on May 25, 2009, and continued through May 30, 2009. 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, startup and heatup activities, and identification and resolution of problems associated with the outage. In addition, the inspectors reviewed the repair activities for the Unit 1 Reactor Core Isolation Cooling (RCIC) steam exhaust stop check and swing check containment isolation valves. The review consisted of as found conditions of the check valves, compliance with technical specifications, appropriate notifications, probable failure mechanisms and the establishment of conditions for the leak rate testing of the RCIC valves.

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

b. Findings

No findings of significance 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:

- QCTS 0600-20, Unit 1 Core Spray Injection Valve Local Leak Rate Test (LLRT) (MO-1(2)-1402-24A/B, MO-1(2)-1402-25A/B) (ISO Valve);
- QCOS 1600-07, Unit 1 & 2 Reactor Boundary Leakage (RCS);
- QCOS 0202-08, Unit 1 Recirculation Discharge Valve Stroke Times for 5A and 5B (IST);
- QCTS 0600-11, Unit 1 High Pressure Coolant Injection (HPCI) Steam Supply Valves LLRT (ISO Valve);
- QCTS 0600-05, Unit 1 Inboard 'C' Main Stream Isolation Valve LLRT (ISO Valve);
- QCOS 1300-17, Reactor Coolant Isolation Cooling (RCIC) Pump Slow Roll After Maintenance (Routine);
- QOS 6500-03, Unit 1 14-1 Undervoltage Logic Test (Routine);
- QCOS 1300-05, Unit 1 RCIC Quarterly Operability Test (Routine); and
- QCOS 2300-05, Unit 1 HPCI Quarterly Operability Test (IST).

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

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, demonstrated operational readiness, and consistent with the system design basis;
- plant equipment calibration was correct, accurate, and properly documented;
- as-left setpoints were within required ranges, and the calibration frequency were in accordance with TS, the USAR, procedures, and applicable commitments;
- measuring and test equipment calibration was current;
- test equipment was used within the required range and accuracy, and applicable prerequisites described in the test procedures were satisfied;
- test frequencies met TS requirements to demonstrate operability and reliability, and 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;

- test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable;
- 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, two inservice testing samples, one reactor coolant system leak detection inspection sample, and three containment isolation valve samples as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings of significance 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 March 12, 2009, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations 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 weaknesses 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 CAP. 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 one sample as defined in IP 71114.06-05.

b. Findings

(1) Inadequate Procedural Guidance for Shutdown After Operating Basis Earthquake

Introduction: Inspectors identified a finding of very low safety significance (Green) for an inadequate procedure which would be used in response to an earthquake event. This procedure did not direct a shutdown in response to an earthquake event in excess of the operating basis earthquake (OBE) threshold as required by regulation.

Description: As part of an emergency preparedness drill on March 12, 2009, the initiating event for the scenario was a seismic event greater than the Quad Cities OBE. The inspectors questioned the licensee on the omission of a directed shutdown in procedure QCOA 0010-09 in the event of an OBE. The licensee reviewed this concern and determined that Quad Cities was not meeting the obligation outlined in 10 CFR 100, Appendix A. Title 10 CFR 100 Appendix A, Section V(a)(2) states, "If vibratory ground motion exceeding that of the Operating Basis Earthquake occurs, shutdown of the nuclear power plant will be required." Upon discovery, the licensee implemented immediate administrative changes to QCOA 0010-09 while formal procedure changes could be processed. The licensee completed appropriate procedure changes to QCOA 0010-09 in May 2009.

Analysis: The inspectors determined that the failure to provide adequate operating procedures was a performance deficiency and a finding. Prior to procedure revision, the licensee would not have performed a shutdown after an OBE as required by regulations. This finding was more than minor because this performance deficiency challenged the Reactor Safety - Mitigating Systems Cornerstone attribute of procedure quality.

The inspectors performed a Phase 1 SDP screening. Inspection Manual Chapter 0609, Attachment 4, Table 4a, Mitigating Systems Cornerstone questions were all answered "no." Therefore the issue screened as Green, or very low safety significance. The inspectors determined that this finding did not have a cross-cutting aspect. This procedure discrepancy was determined to be a latent issue not easily identified through the routine procedure revision process.

Enforcement: Title 10 CFR 50, Appendix B, Criterion V states in part that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures.

Contrary to the above, the procedure used in the response to an earthquake event, QCOA 0010-09, did not direct a shutdown if the earthquake was in excess of the OBE in accordance with 10 CFR 100, Appendix A. Corrective actions included implementing temporary and permanent changes to station operating procedures to restore regulatory compliance.

Because this violation is of very low safety significance, and because the issue was entered into the CAP as Issue Report 894959, this issue is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy
(NCV 05000254/2009003-02, 05000265/2009003-02).

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

.1 Review of Licensee Performance Indicators for the Occupational Exposure Cornerstone

a. Inspection Scope

The inspectors reviewed the licensee's Occupational Exposure Control Cornerstone performance indicator (PI) to determine whether the conditions resulting in any PI occurrences had been evaluated and whether identified problems had been entered into the licensee's CAP for resolution.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors reviewed licensee controls and surveys in the following radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant to determine if radiological controls including surveys, postings, and barricades were acceptable:

- Unit 1 drywell (including under-vessel and various drywell elevations);
- refuel floor of Unit 1 reactor building;
- radwaste building (various areas); and
- Units 1 and 2 reactor building basement.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed the radiation work permits (RWPs) and work packages used to access these areas and other high radiation work areas. The inspectors assessed the work control instructions and control barriers specified by the licensee. Electronic dosimeter alarm setpoints for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors interviewed workers to verify that they were aware of the actions required if their electronic dosimeters noticeably malfunctioned or alarmed.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors walked down and surveyed (using an NRC survey meter) these and other areas to verify that the prescribed RWP, procedure, and engineering controls were in place; that licensee surveys and postings were complete and accurate; and that air samplers were properly located.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed RWPs for work areas with the potential for airborne radioactivity to verify barrier integrity and engineering controls performance (e.g., high-efficiency particulate air ventilation system operation) and to determine if there was a potential for individual worker internal exposures in excess of 50 millirem committed effective dose equivalent. These areas included various Unit 1 drywell locations and the Unit 1 reactor cavity following reactor reassembly and cavity drain-down.

Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and had provided appropriate worker protection.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors assessed the adequacy of the licensee's internal dose assessment process for internal exposures in excess of 50 millirem committed effective dose equivalent. There were no internal exposures greater than 50 millirem since previously reviewed by the inspectors. Nevertheless, the inspectors reviewed the internal dose assessment results and associated calculations for any worker that showed any level of intake as evidenced by a positive whole body count result. All positive count results between March 2008 and May 2009 were reviewed.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors also reviewed the licensee's physical and programmatic controls for highly activated and/or contaminated materials (non-fuel) stored within the spent fuel pool or other storage pools.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed a sample of the licensee's self-assessments, audits, licensee event reports (LERs), and special reports related to the access control program to verify that identified problems were entered into the CAP for resolution.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed corrective action reports related to access controls and any high radiation area radiological incidents (issues that did not count as PI occurrences identified by the licensee in high radiation areas less than 1R/hr) including an incident that occurred on March 27, 2009, during testing of a new TIP automated control unit. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- initial problem identification, characterization, and tracking;
- disposition of operability/reportability issues;
- evaluation of safety significance/risk and priority for resolution;
- identification of repetitive problems;
- identification of contributing causes;
- identification and implementation of effective corrective actions;
- resolution of NCVs tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors evaluated the licensee's process for problem identification, characterization, and prioritization and verified that problems were entered into the CAP and resolved. For repetitive deficiencies and/or significant individual deficiencies in problem identification and resolution, the inspectors verified that the licensee's self-assessment activities were capable of identifying and addressing these deficiencies.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed licensee documentation packages for all PI events occurring since the last inspection to determine if any of these PI events involved dose rates in excess of 25 R/hr at 30 centimeters or in excess of 500 R/hr at 1 meter. Barriers were evaluated for failure and to determine if there were any barriers left to prevent personnel access. Unintended exposures exceeding 100 millirem total effective dose equivalent (or 5 rem shallow dose equivalent or 1.5 rem lens dose equivalent) were evaluated to determine if there were any regulatory overexposures or if there was a substantial potential for an overexposure.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed the following jobs that were being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers:

- Unit 1 incore instrumentation troubleshooting (under-vessel);
- Unit 1 reactor cavity survey and decontamination; and
- Unit 1 drywell cleanup activities.

The inspectors reviewed radiological job requirements for these activities, including RWP requirements and work procedure requirements, and attended pre-job briefings for under-vessel instrumentation trouble-shooting and for drywell basement cleanup work.

This inspection constitutes one sample as defined in IP 71121.01-5.

Job performance was observed with respect to the radiological control requirements to assess whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. The inspectors evaluated the adequacy of radiological controls, including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage, including any applicable audio and visual surveillance for remote job coverage; and contamination controls.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed radiological work in high radiation work areas having significant dose rate gradients to evaluate whether the licensee adequately monitored exposure to personnel and to assess the adequacy of licensee controls. These work areas involved areas where the dose rate gradients were severe; thereby increasing the necessity of providing multiple dosimeters or enhanced job controls.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.5 High Risk Significant, High Dose Rate, High Radiation Area and Very High Radiation Area Controls

a. Inspection Scope

The inspectors held discussions with radiation protection supervisors concerning high dose rate, high radiation area and very high radiation area controls and procedures, as applicable, including procedural changes that had occurred since the last inspection, in order to assess whether any procedure modifications substantially reduced the effectiveness and level of worker protection.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors discussed with radiation protection supervisors the controls that were in place for areas of the plant that had the potential to become very high radiation areas during certain plant operations. The inspectors assessed if plant operations required communication beforehand with the radiation protection group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors conducted plant walkdowns to assess the posting, locking and barrier quality of entrances to numerous high and locked high radiation areas.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation safety work requirements. The inspectors evaluated whether workers were aware of any significant radiological conditions in their workplace, of the RWP controls and limits in place, and of the level of radiological hazards present. The inspectors also observed worker performance to determine if workers accounted for these radiological hazards.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed radiological problem reports for which the cause of the event was due to radiation worker errors to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. Problems or issues with planned or completed corrective actions were discussed with radiation protection supervision.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation protection technician performance with respect to radiation safety work requirements. The inspectors evaluated whether technicians were aware of the radiological conditions in their workplace, the RWP controls and limits in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

This inspection constitutes one sample as defined in IP 71121.01-5.

The inspectors reviewed radiological problem reports for which the cause of the event was radiation protection technician error to determine if there was an observable pattern traceable to a similar cause and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

This inspection constitutes one sample as defined in IP 71121.01-5.

b. Findings

No findings of significance were identified.

2OS2 As-Low-As-Is-Reasonably-Achievable Planning and Controls (71121.02)

.1 Radiological Work Planning

a. Inspection Scope

The inspectors evaluated the licensee's list of Unit 1 refueling outage (Q1R20) work activities ranked by estimated exposure that were in progress and reviewed the following six work activities that were projected to exceed (or had exceeded) initial dose estimates, each with an accrued cumulative dose greater than 5 rem:

- Scaffold Work – Balance of Plant (RWP 10009849);

- Reactor Water Cleanup Regenerative Heat Exchanger Repair (RWP 10010725);
- Drywell Insulation Activities (RWP 10009889);
- Turbine System Valve Work (RWP 10009898);
- Drywell Scaffold Support (RWP 10009888); and
- Drywell Radiation Protection Support (RWP 10009874).

This sample was documented and credited in Inspection Report 05000254/2008002, 05000265/2008002; therefore, this supplemental review does not represent a sample.

The inspectors compared the results achieved (including dose rate reductions and person-rem used) with the intended dose established in the licensee's as-low-as-is-reasonably-achievable (ALARA) planning for these six work activities. Reasons for inconsistencies between intended and actual work activity doses were examined.

This sample was documented and credited in Inspection Report 05000254/2008002, 05000265/2008002; therefore, this supplemental review does not represent a sample.

The inspectors evaluated the interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling, and engineering groups to identify interface problems or missing program elements.

This inspection constitutes one optional sample as defined in IP 71121.02-5.

The licensee's ALARA work-in-progress reports (for ongoing and completed Q1R20 outage work activities) were evaluated to verify that outage jobs that accrued dose greater than estimated were evaluated, that actions were taken to reduce dose as the job progressed, and to verify that problems were entered into the licensee's CAP.

This sample was documented and credited in Inspection Report 05000254/2008002, 05000265/2008002; therefore, this supplemental review does not represent a sample.

b. Findings

No findings of significance were identified.

.2 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The licensee's process for adjusting exposure estimates or re-planning work (when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered) was evaluated. This included determining whether adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles or whether they resulted from failures to adequately plan or to control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process.

This sample was documented and credited in Inspection Report 05000254/2008002, 05000265/2008002; therefore, this supplemental review does not represent a sample.

b. Findings

No findings of significance were identified.

.3 Job Site Inspections and ALARA Control

a. Inspection Scope

The inspectors reviewed exposures of individuals from selected work groups that were involved in Q1R20 high dose work to evaluate any significant exposure variations among workers and to determine whether any significant exposure variations were the result of worker job skill differences or whether certain workers received higher doses because of poor ALARA work practices.

This inspection constitutes one optional sample as defined in IP 71121.02-5.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Reactor Coolant System Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the RCS Leakage performance indicator for Quad Cities Unit 1 and 2 for the period from the April 1, 2008 through the March 31, 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports, and NRC integrated inspection reports for the period of April 1, 2008 through March 31, 2009, to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified.

This inspection constituted two reactor coolant system leakage samples as defined in IP 71151-05.

b. Findings

No findings of significance were identified.

.2 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors sampled licensee submittals for the Occupational Radiological Occurrences performance indicator for the period from the second quarter 2008 through April 2009. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in the NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's assessment of the PI for occupational radiation safety to determine if indicator related data was adequately assessed and reported. To assess the adequacy of the licensee's PI data collection and analyses, the inspectors discussed with radiation protection staff the scope and breadth of its data review, and the results of those reviews. The inspectors independently reviewed electronic dosimetry dose rate and accumulated dose alarm and dose reports and the dose assignments for any intakes that occurred during the time period reviewed to determine if there were potentially unrecognized occurrences. The inspectors also conducted walkdowns of locked high radiation area entrances to determine the adequacy of the controls in place for these areas. Documents reviewed are listed in the Attachment to this report.

This inspection constitutes one occupational radiological occurrences sample as defined in IP 71151-05.

b. Findings

No findings of significance 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. Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that 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 attached List of Documents Reviewed.

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 of significance were identified.

.2 Daily Corrective Action Program Reviews

a. 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 of significance were identified.

.3 Selected Issue Follow-Up Inspection: IR 906008, 1/2 Emergency Diesel Generator Cooling Water Pump Failed to Swap Feeds

a. Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting a failure of the 1/2 EDG cooling water pump to transfer to Unit 2 when control power was transferred from Unit 1 to Unit 2 on April 10,2009. Investigation following the event identification revealed that on March 25 the control power fuse blew when operators were changing light bulbs and was not detected until the condition revealed itself during the surveillance activity on April 10. The failure of that fuse de-energized the 1/2 EDG control power transfer circuit and resulted in the EDG being inoperable to Unit 2 for 17 days. As a result, the station was not in compliance with Technical Specification 3.8.1, "AC Sources - Operating." This condition was later documented by the licensee in LER 05000265/2009-001-00 (See Section 4OA3 of this report for closure discussion for this LER.).

The inspectors reviewed the initial report and subsequent troubleshooting activities. The inspectors interviewed personnel involved in the event and station supervisory personnel. Subsequent to those interviews, inspectors reviewed the licensee's root cause evaluation report and corrective actions to prevent recurrence. Documents reviewed as part of this inspection are listed in the Attachment to this report.

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

b. Findings

Introduction: A Green finding and a Non-Cited Violation (NCV) of Quad Cities Unit 2 Renewed License No. DPR-30 condition 3.B were self revealed on April 10, 2009, when a previously unidentified blown fuse on a 1/2 EDG control power transfer circuit resulted in the EDG being inoperable to Unit 2 for 17 days.

Description: On April 10, 2009, during a monthly 1/2 EDG performance test, 1/2 EDG output power was transferred from Unit 1 to Unit 2. However, when the 1/2 EDG was loaded to Unit 2 the power supply for the 1/2 EDG auxiliary components did not automatically transfer to Unit 2 per design but rather remained aligned to Unit 1. Troubleshooting identified that the 1/2 EDG transfer logic circuit had a blown fuse which prevented the transfer from occurring. After troubleshooting verified no faults on the circuit on April 11, the fuse was replaced and the circuit was verified operable. With the circuit de-energized, there was no 125 Vdc logic power available to the transfer interlock circuit which would allow the 1/2 EDG to support a Unit 2 loss of coolant accident (LOCA) with a concurrent Unit 1 degraded voltage condition.

Follow-up investigation to the April 10 event determined that on March 25, 2009, the system engineer had performed a walkdown of the 1/2 EDG, noted that the blue, “Transfer Power Available” light in the 1/2 EDG room at panel 1/2-2212-127 was not illuminated, and notified operations. An operator attempted to replace the light bulb after verifying the installed bulb had burned out. When the replacement bulb was screwed in, the bulb “flashed” and then immediately burned out (March 25 at 12:00 p.m.).

The system engineer reported the condition to the control room and stated that based on what he could see, everything else looked fine and the problem appeared to be a bad light socket. He then generated Issue Report 897524 with all of the appropriate information included. At this time, operations determined that the light socket was bad based on the information provided by the system engineer, noted the deficiency, but did not evaluate if the circuit suffered any adverse consequences. The shift manager on the afternoon shift completed the operable basis and reportable basis for Issue Report 897524 that the system engineer had written on the Issue Report 897524. The afternoon shift manager also concluded that this was a light indication issue only, and did not consider pulling out any electrical prints, or asking Electrical Maintenance to test the circuit. His conclusion was based on the system engineer’s written recommendation in the Issue Report to only replace the light bulb socket and bulb and his previous conversation with the dayshift shift manager.

Undiscovered by the individuals involved at the time, a fuse had also blown when the light bulb “flashed” causing the 1/2 EDG transfer interlock circuit to be disabled. This blown fuse resulted in the 1/2 EDG being inoperable to Unit 2 from March 25, 2009, (12:00 p.m.) to April 11, 2009, (02:34 a.m.) when the fuse was replaced and the circuit was restored.

Analysis: Inspectors determined that the failure to take effective action to ensure the facility was operated in accordance with Technical Specifications was a performance deficiency warranting further evaluation. The inspectors determined the finding was more than minor because the finding is associated with the Mitigating Systems Cornerstone attribute of equipment reliability and affected the cornerstone objective by impacting availability, reliability and capability of the Unit 2 emergency electrical supplies. Specifically, allowing the non-conforming condition on the 1/2 EDG to linger while performing maintenance activities on the Unit 2 EDG challenged the availability of emergency AC power to Unit 2.

The inspectors reviewed this finding in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspections Findings for At-Power Situations." The postulated accident where the 1/2 EDG would have failed its safety function is in the case of a LOOP to both units, then a subsequent LOCA on Unit 2. By default, the 1/2 EDG will supply power to Unit 1. While loaded to Unit 1, if a LOCA signal is present from Unit 2, the 1/2 EDG will disconnect from Unit 1, and will auto transfer to Unit 2 and begin load sequencing for a LOCA. The auto transfer would not have occurred to Unit 2 with the blown fuse. Operators would have had the ability to transfer the 1/2 EDG to Unit 2 manually from the control room. During the period of March 25 to April 10, the Unit 2 EDG was inoperable during the performance of its 24 hour endurance run. At this time, the Unit 1 EDG and both station blackout diesels were operable. The Significance Determination Process performed by the residents showed risk significance much lower than 1×10^{-6} (Green). This SDP evaluation has been verified by the regional senior risk analyst.

Inspectors determined this finding to be cross-cutting in the area of Problem Identification and Resolution for the corrective action component because station personnel failed to investigate the non-conforming condition as directed by station procedures to adequately assess the impact on system operability and did not meet procedural requirements for evaluating operability (P.1(c)). Exelon procedure OP-AA-108-115, "Operability Determinations," described the process for determining equipment operability. Step 4.1.6 required Operations shift management to immediately determine operability from a detailed examination of the deficiency. This procedure also referenced OP-AA-108-115-1002, "Supplemental Consideration for On-shift Immediate Operability Determinations." This procedure identified two specific tasks required to be accomplished as part of the operability determination:

- Step 4.4 - Identify how the affected part, component, subsystem, etc., contributes to the overall function of the SSC; and
- Step 4.5 – Evaluate the effects of the condition and possible failure modes on the ability of the SSC to perform its required function.

Inspector interviews with the senior reactor operators performing the operability evaluation indicated that, contrary to the procedural requirement discussed above, they did not fully understand the circuit function and were relying on the unvalidated input from the subject matter expert to arrive at the operability evaluation. The failure of the licensee's staff to investigate the non-conforming condition to facilitate an adequate assessment of system operability without reliance on unvalidated assumptions did not meet procedural requirements and resulted in a failure to identify the inoperable condition in time to prevent the violation of Technical Specifications.

Enforcement: Quad Cities Unit 2 Renewed License No. DPR-30 condition 3.B stated in part that "The licensee shall operate the facility in accordance with the Technical Specifications." Technical Specification 3.8.1, "AC Sources – Operating" limiting condition for operation stated in part that two diesel generators shall be operable. With one of the required EDGs inoperable (Condition B of TS 3.8.1), required action B.4 directed the licensee to "Restore the required DG to OPERABLE status within 7 days."

When required action B.4 was not satisfied, TS 3.8.1 condition F required the unit to be in Mode 3 in 12 hours and to be in Mode 4 in 36 hours.

Contrary to the requirements above, the licensee did not identify the inoperable 1/2 diesel generator control circuit when the non-conforming condition was identified on March 25, 2009, and therefore did not take the required actions in the specified time frame to ensure Unit 2 continued to be operated in accordance with Technical Specifications. When the condition was self-revealed, the licensee investigated and on April 11, 2009, restored operability of the 1/2 EDG when the fuse was replaced and the circuit was restored. In addition to restoring operability of the circuit, the licensee's corrective actions included training for operators on the circuit function and operability impact, development of additional procedural guidance relating to validating information provided by subject matter experts, and additional management coaching and oversight to reinforce operator's effective questioning attitude and engineering's evaluation of off-normal plant indications.

Because this violation was of very low safety significance and the issue was entered into the licensee's CAP as Issue Report 897524, this violation is being treated as a NCV, consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000265/2009003-03)**.

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

.1 Trip of Unit 2 Fuel Pool Cooling Water Pumps During Scorpion Platform Removal

a. Inspection Scope

The inspectors reviewed the equipment response to a trip of the Unit 2 fuel pool cooling pumps on skimmer surge tank low level. The low level condition occurred as personnel on the refuel floor were removing the Scorpion platform from the Unit 1 reactor cavity. The Scorpion platform is used by the licensee to allow inspectors to examine reactor vessel internal components without relying on the refueling bridge. The Scorpion platform sits down into the water in the reactor cavity and rests on the outside cavity wall. It is low enough that the refueling bridge will pass over it, allowing inspection activities to continue while the bridge is in use. Initially both Unit 1 fuel pool cooling pumps ('A' and 'B') and both Unit 2 fuel pool cooling pumps ('A' and 'B') were operating in the alternate decay heat removal mode and being relied upon as the alternate means of shutdown cooling to remove decay heat from the irradiated fuel in the reactor core and the spent fuel pool. Documents reviewed in this inspection are listed in the Attachment to this report.

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

b. Findings

Introduction: A self-revealed finding of very low safety significance (Green) and NCV of 10 CFR 50.65(a)(4) was identified on May 11, 2009, when the licensee's staff failed to manage water level in the spent fuel pool and associated skimmer surge tanks while removing the Scorpion platform from the Unit 1 reactor cavity. Both Unit 2 fuel pool cooling pumps tripped as a result of the skimmer surge tank low level that occurred as the bridge was lifted out of the pool.

Description: On May 11, 2009, both loops of residual heat removal shutdown cooling were removed from service for a planned maintenance activity. Both Unit 1 fuel pool cooling pumps and both Unit 2 fuel pool cooling pumps were aligned for alternate decay heat removal configuration using QCOP 1000-44, “Alternate Decay Heat Removal.” This alignment satisfied the Technical Specification 3.9.8 requirement for an alternate decay heat removal method with the required train of shutdown cooling inoperable. In this condition, shutdown risk was considered acceptable and the fuel pool cooling equipment was administratively protected by controlling work with a potential to impact the pumps and to ensure continuation of the key shutdown safety function of decay heat removal.

On May 11, 2009, at 5:00 p.m., the refuel floor manager notified operators in the main control room that the reactor services group would be stopping fuel movement and breaking the open line of communication between the refuel floor and the main control room to remove the Scorpion platform from the Unit 1 reactor cavity. The activity of placing and removing the Scorpion platform into and out of the reactor cavity was controlled by work instructions in WO 01044112. The work instructions include an “impact statement” that states: “Installation and removal of the Scorpion platform will cause fluctuations in spent fuel pool level, Operations MUST either be in attendance on the refuel floor during installation and removal OR in constant communications with the Refuel Floor.” Neither the impact statement nor the work instructions identified the negative consequences of level change. While the impact statement provides information about the work activity to help the various work groups communicate more clearly, it is not part of the step-by-step work instructions governing the task execution. The procedure step in the body of the work instruction required the refuel floor operator to notify the nuclear station operator (NSO) of the pending removal of the Scorpion platform which the refuel team accomplished. With no preplanned specified action in the body of the procedure, the operating crew was then left to respond as they understood the condition.

Operators did not take action to manage or intervene in the activity in response to the initial communication of impending removal of the Scorpion platform when the refuel floor manager contacted the NSO. This was due to the operators’ inconsistent understanding of the activity and its potential impact on pool water level (and thus on the key shutdown safety component of decay heat removal) resulting in an incorrect assumption that the effect on fuel pool water level would be minimal. The refuel floor manager was satisfied with the communications to the control room because within the reactor services group there was the expectation that the operators had a full understanding of the work that was in progress and the potential impact.

At 6:21 p.m., the refuel floor again contacted the Unit 1 NSO to notify him that they were pulling the Scorpion platform out of the reactor cavity. At approximately 6:31 p.m., the main control room received Unit 2 alarm 902-4 D24, “Skimmer Surge Tank Low Level.” The operators announced the alarm and dispatched an equipment operator to the tank to verify level. At 6:34 p.m., alarm 902-4 G24, “Fuel Pool Cooling Pumps Trip,” was received for the Unit 2 ‘A’ and ‘B’ fuel pool cooling pumps. The Unit 2 operators referenced QCOA 1900-03, “Loss of Fuel Pool Cooling with Unit Shutdown for Refueling,” and determined that the fuel pool cooling pump trip was due to low Unit 2 skimmer surge tank level from the Scorpion platform being removed from the Unit 1 reactor cavity. At 6:36 p.m., Unit 2 alarm 902-4 D24, “Skimmer Surge Tank Low Level,” cleared. This was due to the Unit 1 skimmer surge tank level lowering through the crosstie and equalizing with the Unit 2 skimmer surge tank level, and due to the equipment operator filling the Unit 2 skimmer surge tank. At 6:43 p.m., the radwaste operator restarted the Unit 2 ‘A’ and ‘B’ fuel pool cooling pumps. The Unit 1 fuel pool cooling pumps had remained running throughout the event with no issues.

Analysis: The inspectors determined that the failure to take adequate action to manage the risk associated with a maintenance activity with a potential to affect a key shutdown safety function was a performance deficiency and a finding. The inspectors determined this finding was more than minor because the failure to implement the management actions resulted in the critical safety function being degraded and is associated with 10 CFR 50.65(a)(4) risk management. The inspectors performed a Phase 1 SDP evaluation and determined that the issue was of very low safety significance (Green) because the Unit 1 pumps remained running with no issues during the event and plant operators were able to recover the Unit 2 cooling pumps before any discernable change in temperature occurred (answers to all questions of IMC 0609, Attachment 4, Table 4a, Mitigating Systems Cornerstone and Barrier Cornerstone were “no” and the issue screened as Green). Since the finding concerned risk management actions, the inspectors verified the finding was Green using IMC 0609, Appendix K flowcharts and validated that there was no change in risk thresholds as a result of the event.

The inspectors also determined that the licensee had multiple opportunities in the outage preparation and work implementation process to identify the potential operational impact and properly coordinate the activities between the two different departments to reduce the risk to the key shutdown safety feature. Station work history indicated the same problem occurred during the platform removal from the Unit 2 reactor cavity following Q2R19 in March of 2008. As a result, inspectors determined that the finding was cross-cutting in the area of Human Performance - Work Control for failure to appropriately coordinate work activities by incorporating actions to address the need for work groups to communicate, coordinate and cooperate with each other during activities in which interdepartmental coordination is necessary to assure plant and human performance (H.3(b)).

Enforcement: Title 10 CFR 50.65(a)(4) requires, in part, that before performing maintenance activities (including but not limited to surveillances, post-maintenance testing, and corrective and preventative maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activity.

Contrary to the above, the licensee failed to manage the risk associated with removal of the Scorpion platform from the Unit 1 reactor cavity pool, in that, although the risk assessment in place considered the fuel pool cooling pumps to be protected equipment, the maintenance activity that had the potential to impact the equipment providing the key shutdown safety function was allowed to proceed with no compensatory or control measures in place to reduce or manage the risk to the protected equipment. As a result, skimmer tank water level was allowed to change enough to trip the Unit 2 fuel pool cooling pumps. Immediate corrective actions for this event included refilling the skimmer surge tank and restarting the fuel pool cooling pumps. Additional corrective actions included revising the implementing procedure to include specific actions to address the affect on fuel pool and skimmer water level when the platform is installed or removed and training for operators and reactor services personnel on expectations for detailed communications and questioning attitude.

Because this violation is of very low safety significance, and because the issue was entered into the CAP as Issue Report 867904, this issue is being treated as a NCV consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2009003-04, 05000265/2009003-04)**.

.2 (Closed) Licensee Event Report 05000265/2009-001-00: Failure of Common Unit Emergency Diesel Generator Auxiliaries to Transfer Power Sources to Support Unit 2

This event was discovered on April 10, 2009, during a monthly 1/2 EDG performance test when 1/2 EDG output power was transferred from Unit 1 to Unit 2. When the1/2 EDG was loaded to Unit 2, the power supply for the 1/2 EDG auxiliary components did not automatically transfer to Unit 2 per design but rather remained aligned to Unit 1. Troubleshooting identified that the 1/2 EDG transfer logic circuit had a blown fuse and was de-energized. With the circuit de-energized, there was no 125 Vdc logic power available to the transfer interlock circuit which would allow the 1/2 EDG to support a Unit 2 LOCA with a concurrent Unit 1 degraded voltage condition. This previously unidentified blown fuse resulted in the 1/2 EDG being inoperable to Unit 2 from March 25, 2009 (12:00 p.m.) to April 11, 2009, (02:34 a.m.) when the fuse was discovered and replaced. Documents reviewed as part of this inspection are listed in the Attachment to this report. Findings associated with this event are documented in section 4OA2.3 of this report. This LER is closed.

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

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On July 9, 2009, the inspectors presented the inspection results to T. Tulon 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 conducted:

- On April 23, 2009, the inspectors presented the ISI results to Mr. T. Tulon and other members of the licensee staff.
- On May 22, 2009, the results of the radiological access control and ALARA program inspection with Mr. T. Tulon and other licensee staff.

The licensee acknowledged the issues presented and the inspectors confirmed that none of the potential report input discussed was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Tulon, Site Vice President
R. Gideon, Plant Manager
R. Svaleson, Operations Manager
H. Madronero, Engineering Manager
W. Beck, Regulatory Assurance Manager
J. Burkhead, Nuclear Oversight Manager
K. Moser, Training Manager
V. Neels, Chemistry/Environ/Radwaste Manager
D. Collins, Radiation Protection Manager
A. Williams, Radiation Protection Engineering Supervisor
D. Thompson, Security Manager

Nuclear Regulatory Commission

M. Ring, Chief, Reactor Projects Branch 1

Illinois Emergency Management Agency

R. Zuffa, Unit Supervisor, Resident Inspector Section

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000254/2009003-01	NCV	Inadequate Procedural Adherence During Unit 1 TIP PM Testing
05000254/2009003-02; 05000265/2009003-02	NCV	Inadequate Procedural Guidance for Shutdown After Operating Basis Earthquake
05000265/2009003-03	NCV	1/2 EDGCWP Failed to Swap Feeds
05000254/2009003-04; 05000265/2009003-04	NCV	Trip of Unit 2 Fuel Pool Cooling Water Pumps During Scorpion Platform Removal

Closed

05000254/2009003-01	NCV	Inadequate Procedural Adherence During Unit 1 TIP PM Testing
05000254/2009003-02; 05000265/2009003-02	NCV	Inadequate Procedural Guidance for Shutdown After Operating Basis Earthquake
05000265/2009003-03	NCV	1/2 EDGCWP Failed to Swap Feeds
05000254/2009003-04; 05000265/2009003-04	NCV	Trip of Unit 2 Fuel Pool Cooling Water Pumps During Scorpion Platform Removal
05000265/2009-001-00	LER	Failure of Common Unit EDG Auxiliaries to Transfer Power Sources to Support Unit 2

LIST OF DOCUMENTS REVIEWED

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

Section 1EP6

- IR 894959; Seismic OBE Shutdown Needs Incorporation into Procedures; 03/19/09
- QCOA 0010-09; Earthquake; Revision 11
- EP-AA-1006; Quad Cities Annex Emergency Action Levels; Revision 27
- Quad Cities UFSAR, Section 3.7, Seismic Design

Section 1R01

- OP-AA-108-111-1001; Severe Weather and Natural Disaster Guidelines; Revision 03
- QCOS 0010-06; Key Phone Numbers and Checklists for Referenced 10 Block Procedures; Revision 12
- QCOA 6000-03; Low Switchyard Voltage; Revision 8
- QCOA 6100-03; Loss of Offsite Power; Revision 25
- Exelon Letter SVP-09-026 from Tim Tulon to Stephen Kuczynski; quad Cities Generating Station Certification of 2009 Summer Readiness; May 15, 2009
- IR 924666; 1-1001-7C Will Not Open; 05/28/2009
- WO 1239116; Valve Does Not Operate From the Control Room; 05/29/2009
- IR 808640; 2A Isophase Bus Duct Blower Belts are Dry, Brittle, & Cracked; 8/19/2008
- IR 862749; Isophase Bus Duct Cooling Augmentation TMOD Summer Readiness; 01/05/2009

Section 1R04

- QCOP 6600-02; Unit 0 Diesel Generator Preparation for Standby Operation
- QCOS 6900-01; Station Battery Weekly Surveillance; Revision 27
- QOP 6900-01; 250 VDC Electrical System; Revision 31
- QOP 6900-02; 125 VDC Electrical System; Revision 30

Section 1R05

- QCMMS 4100-01; Fire Extinguisher Inspection, Revision 29
- Pre-plan TB-77; Fire Zone 6.1.B, Unit 1 Turbine Bldg. El 615’-6”, “B” Battery Charger Room U-1; Revision 24
- Pre-plan TB-77; Fire Zone 6.1.A, Unit 1 Turbine Bldg. El 615-6”, “A” Battery Charger Room U-1; Revision 24
- Pre-plan TB-68; Fire Zone 8.2.6.B, Unit 1 Turbine Bldg. El. 595’-0” L.P. Heater Bay; Revision 17
- Pre-plan TB-81; Fire Zone 8.2.7.B, Unit 1 Turbine Bldg. El. 608’-6” LP Heater Bay (west)
- Pre-plan TB-70; Fire zone 5.0, Unit 2 Turbine Bldg. El. 595’-0” Safe Shutdown Pump Room; Revision 22

Section 1R06

- QCMPM 1500-03; Reactor Building Basement Submarine Door Preventative Maintenance; Revision 7
- QCAP 0250-06; Control of In-Plant Flood Barriers and Watertight "Submarine" Doors; Revision 10

Section 1R07

- IR 916984, PSU Q1R20 As Found Inspection of 1A RHR HX Upper Channel, 05/07/09
- WO# 835123, Open and Eddy-Current Test 1A RHR HX
- ER-AA-330-009 Attachment 3, ASME Section XI Repair/Replacement Plan, Revision 5
- CC-AA-501-1022 Attachment 1, High Risk/High Value Welding Screening Checklist, Revision 1

Section 1R08

- AR910274, Q1R20 RHR Pipe Support condition During ISI Inspection, April 22, 2009
- AR910522, Documentation of ISI Weld Reselection, April 22, 2009
- AR757382, Flaw Acceptance Code Case Not Applicable to Quad, March 31, 2008
- AR624605, Q1R19 – Incorrect Component Examined During ISI, May 2, 2007
- GE-ADM-1002, Procedure for Nondestructive Examination Data Review and Analysis of Recorded Indications, Version No. 5
- GE-ADM-1062, Procedure for Determining and Documenting Examination Requirements for Risk-Informed Inservice Inspections, Version No. 1
- GE-PDI-UT-1, PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds, Revision 6
- ER-AA-335-016, VT-3 Visual Examination of Component Supports, Attachments And Interiors of Reactor Vessels, Revision 5
- SVP-07-049, Quad Cities Nuclear Power Station Unit 1 90 – Day Post Outage ISI Letter, August 20, 2007

Section 1R12

- IR 918439; Unit 2 Fuel Pool Pumps Tripped Due to Refueling Activities; 05/11/2009
- IR 760561; Q2R19 1B FPC Pump Auto Tripped From SFP Scorpion Removal:
- USAR Section 5.4.7.2.3, Other Functions of the Residual Heat Removal Systems; Revision 6
- Z1900 System Evaluation performed by System engineer on 05/02/09 for Previous 2 year Interval

Section 1R13

- IR 923468; RCIC Turbine Trip During Performance of QCOS 1300-05; 5/24/2009
- IR 923536; HPCI Condensate Pump Shaft Seal Leak Approximately 60 DPM; 5/24/2009

Section 1R15

- IR 900389; Incorrect Tap Settings Utilized in Aux Power Calculation; 3/31/2009
- EC 374910, Revision 00; Incorrect Tap Settings Utilized in Aux Power Calculation
- EC 374910, Revision 01; Incorrect Tap Settings Utilized in Aux Power Calculation
- QDC-6700-E-1503, Revision 2; AC Auxiliary Analysis

- IR 910091; Barometric Condenser Condensate Pump Tripped During QCOS 1300-05; 4/21/2009
- QCOS 1300-05; Quarterly RCIC Pump Operability Test; Revision 47
- EC 375218, Revision 00; Effects on RCIC Operability w/loss of Barometric Condenser Pump
- EC 375236, Revision 00; OP EVAL for RCIC Barometric Condenser (Vacuum Tank) High Level
- Technical Specification 3.5.3 and Associated Basis; RCIC System
- IR 905945; Replacement Valve Not Suitable For End Use Application; 4/10/2009
- ECR 389841; Engineering Response to Questions from IR 905945; 4/8/2009
- IR 915723, MSLB Conditions Impact TRM Allowed Value Calcs for 1(2)-0263-73A(B)
- EC 370997, Revision 1; MSLB Calc 3C2-0181-001 Didn't Consider Opening to Reactor Building
- EC 370997, Revision 2; MSLB Calc 3C2-0181-001 Didn't Consider Opening to Reactor Building
- IR 782575; MSLB Calc 3C2-0181-001 Didn't Consider Opening to Reactor Building; 6/3/2008
- IR 923176; 3E Relief Valve Temp Trending Up as Rx Pressure Increased; 5/23/2009
- IR 925804; 3E Relief Valve High Temperature (Approx 290 Deg F); 5/30/2009
- IR 926537; Unit 1 3E Relief Valve Has High Tail Pipe Temp; 06/01/2009
- QCOS 0203-02; Safety and Relief Valve Temperature Surveillance; Revision 25
- QCOS 0203-03; Main Steam Relief Valve Operability Test; Revision 24
- ER-AB-331-1006; BWR Reactor Coolant System Leakage Monitor and Action Plan; Revision 1
- OP-AA-106-101-1006; OTDM for 3E Relief Valve High Temperature; Revision 6

Section 1R18

- EC 366310, Revision 002; Reactor recirculation MG Set Replacement with Adjustable Speed Drive (ASD) Units
- EC 372983, Revision 000; Lift Lead To Restore Control Rod Position indication and Remove Nuisance Overtravel Alarm Indication
- WO 01184076; Bad RPIS Indication For Unit 2 CRD 50-27, Alarm 902-5 A2; 11/14/2008
- WO 01185886; Restore Lead lifted for EC 372983 for RPIS 50-27 (N-7); 11/14/2008
- EC 365238, Replacement of the Unit 1 Automated TIP Control Unit (ATCU)
- TIC-1844, Revision 0; Automated TIP Control Unit (ATCU) Modification Test
- IR 898897; Unexpected Withdrawal of a TIP into the Reactor Building; 03/27/09
- IR 901970-02; Root Cause Evaluation Report: Lack of Management Expectations for Test Coordinator Performance Led to Increased Dose Rates in Unit 1 Reactor Building During TIP Modification Test
- HU-AA-102; Technical Human Performance Practices; Revision 2
- HU-AA-104-101; Procedure Use and Adherence; Revision 3
- CC-AA-107; Configuration Change Acceptance Testing Criteria; Revision 7
- QCOP 0700-06; Unit 2 Traversing In-Core Probe (TIP); Revision 12
- QCOP 0700-03; Local Power Range Monitoring (LPRM) Operation; Revision 14
- QCIPM 0756-01; LPRM Detector I-V Curve Data; Revision 09
- QCIPM 0756-03; LPRM Flux Amplifier Gain Adjustment; Revision 06

Section 1R19

- WO 01196025; 1/2 B CR HVAC Chiller High Vibration Amplitudes
- QCOP 5750-02; Reactor Building Ventilation; Revision 19
- WO 01237356; OP 1C RB Exhaust Fan Verify Trip on UV; 5/21/2009

- QCEM 0600-09; Installation of VOTES Sensor on Limitorque Motor Operated Valves; Revision 005
- QCEM 0600-12; Functional Testing and Limit Switch Verification of Motor Operated Valves; Revision 027
- QCOS 0250-04; Main Steam Isolation Valve Closure Timing; Revision 22
- QCOS 0250-01; Main Steam Isolation Valve Closure SCRAM Sensor Channel Functional Test; Revision 27
- QCOS 1400-04; Core Spray Pump Operability Test; Revision 15

Section 1R20

- GE/Hitachi Nonconformance Report No. WFSC-09-017; Control Rod Blade Drive Assemblies; including resolution dated 4/29/2009
- IR 912458; Vendor Did Not Store CRDs Per ANSI Level B Requirements; 04/28/2009
- ECR 390095; Improper CRD Storage at Vendor Facilities; 04/28/2009
- IR 923468, RCIC Turbine Trip During Performance of QCOS 1300-05; 05/24/09
- IR 923557, RCIC Stop Check Valve 1-1301-64 Will Not Close; 05/24/09
- WO 1238214, MM Repair 1-1301-41
- WO 1238274, RCIC Stop Check Valve 1-1301-64 Will Not Close
- Event Notification 45092, Inoperable RCIC Primary Containment Isolation Valves; 05/25/2009

Section 1R22

- QCOS 1300-17; RCIC Pump Test Slow Roll after Maintenance; Revision 24
- QCOS 1300-05; Quarterly RCIC Pump Operability Test; Revision 47
- QCOS 2300-05; Quarterly HPCI Pump Operability Test; Revision 63
- IR 923209; RCIC Condensate Pump Motor Failed to Pump Midway Thru Test; 05/23/2009
- IR 910091; Barometric Condenser Condensate Pump Tripped During QCOS 1300-05; 4/21/2009
- EC 375218, Revision 00; Effects on RCIC Operability w/loss of Barometric Condenser Pump
- EC 375236, Revision 00; OP EVAL for RCIC Barometric Condenser (Vacuum Tank) High Level
- Technical Specification 3.5.3 and Associated Basis; RCIC System
- QCTS 0600-20; Init 1 Unit 1 Core Spray Injection Valve Local Leak Rate Test (MO-1(2)-1402-24A/B, MO-1(2)-1402-25A/B); Revision 16
- QCOS 0202-08; Reactor Recirculation Cold Shutdown Power Operated Valve Test; Revision 13
- QCOS 0202-15; Unit 1 Reactor Recirculation Pump and Valve Logic Test; Revision 05
- QCTS 0600-11; HPCI Steam Supply Local Leak Rate Test (MO-1(2)-2301-4, MO-1(2)-2301-5); Revision 09
- QCTS 0600-06; Main Steam Line Drain Valve Local Leak Rate Test (MO-1(2)-220-1, MO-1(2)-220-2); Revision 11
- QCTS 0600-05; Main Steam Isolation Valve Local Leak Rate Test (AO-1(2)-203-1(A, B, C, D), AO-1(2)-203-2(A,B,C,D))
- QOS 6500-03; 4KV Bus 14-1 Undervoltage Functional Test; Revision 30

Section 2OS1

- RWP 10009896; Under-Vessel Instrumentation Work for Q1R20; Revision 0 and associated ALARA Plan; dated March 16, 2009
- RWP 10009901; Reactor Disassembly/Reassembly and Cavity Work; Revision 1 and associated ALARA Plan and TEDE ALARA Evaluations; Revision 0
- RP-AA-460; Controls for High and Locked High Radiation Areas; Revision 19
- Self-Assessment Report; ALARA Planning and Controls and Access Control to Radiologically Significant Areas; dated March 30, 2009
- NF-AA-390; Spent Fuel Pool Material Control; Revision 2
- Spent Fuel Pool Material Log/Inventory; May 10, 2009
- AR 00855549; Lock Mechanism Failure; December 12, 2008
- AR 00789362; Check-In Improvement of High Radiation Area Keys issued to Operations and Security; dated June 23, 2008
- AR 00881660; Individual Received Dose Rate Alarm; dated February 17, 2009
- AR 915694; Worker Enters Area on Incorrect RWP; dated May 4, 2009
- Nuclear Oversight Objective Evidence Report; High Radiation Area Controls; Assessment Conducted November 18 – 21, 2008
- Nuclear Oversight Objective Evidence Report; Radworker Performance and On-Line Dose Control; Assessment Conducted November 17 – 26, 2008
- ALARA Plan for TIP System Maintenance Outside of Drywell (RWP 10010496); dated March 25, 2009
- AR 00898897 and Associated Prompt Investigation; Unit 1 TIP Withdrew into the Drive Machine During Testing; dated March 27, 2009
- AR 00907243; Off-Gas Filter Building LHRA Door Lock Failure; dated April 14, 2009
- AR 00909636; High Radiation Area Turnstyle Found Unlocked; dated April 20, 2009

Section 2OS2

- AR 00917794; Inadequate ALARA Controls; dated May 9, 2009
- Balance of Plant Scaffold Work Dose Estimate Spread Sheets for Q1R20; undated
- AR 00917699; Q1R20 ALARA Scaffolds; dated May 9, 2009
- ALARA Plans for RWCU Heat Exchanger Leak Repair (RWP 10010725); Revision 0 and Revision 1 (dated May 9, 2009)
- ALARA Work-In-Progress Reviews for RWP 10010725; RWCU Heat Exchanger Repair; dated May 10, 11 and 12, 2009
- ALARA Post-Job Review for RWP 10010725; RWCU Heat Exchanger Repair; dated May 18, 2009
- ALARA Plan for Drywell Insulation Activities (RWP 10009889); Revision 0
- Drywell Insulation Work Dose Estimate Spread Sheets for Q1R20; undated
- ALARA Work-In-Progress Reviews for RWP 10009889; Drywell Insulation; dated May 7-10, 2009
- ALARA Plan for Turbine System Work (RWP 10009898); Revision 0
- ALARA Work-In-Progress Reviews for RWP 10009898; dated April 29, May 4, May 7,
- and May 11, 2009
- ALARA Plan for Drywell Scaffolds (RWP 10009888); Revision 0
- ALARA Work-In-Progress Review for RWP 10009888; dated May 7, 2009
- AR 00916283; Unnecessary Scaffold Built in Drywell; dated May 6, 2009
- ALARA Work-In-Progress Review for RWP 10009874; dated May 15, 2009

Section 4OA1

- NEI 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 5
- LS-AA-2100; Monthly Data Elements for NRC Reactor Coolant System (RCS) Leakage; Revision 5
- Electronic Dosimetry Alarm Transaction Reports; April 2008 – May 2009
- LS-AA-2140; Monthly PI Data Elements; April 2008 – April 2009

Section 4OA2

- IR 906008; 1/2 EDG Cooling Water Pump Failed to Swap Feeds; 04/10/2009
- WO 1216999; Troubleshooter for 1/2 EDG, 4/11/2009
- IR 897524; 2217-127 Transfer Power Available Light Out; 3/25/2009
- TS 3.8.1 AC Sources – Operating, Amendment 199/195

Section 4OA3

- IR 918439; Unit 2 Fuel Pool Pumps Tripped Due to Refueling Activities; 05/11/2009
- IR 760561; Q2R19 1B FPC Pump Auto Tripped From SFP Scorpion Removal:
- QDC-1900-M-0728, Revision 0; SFP, RHR, and RBCCW Heat Exchanger Analysis
- QDC-1900-N-1705, Revision 0; Alternate Decay Heat Removal (ADHR) System Qualification For Q1R20 Outage
- QCOA 1900-03; Loss of Fuel Pool Cooling with Unit Shutdown for Refueling; Revision 8
- QCOP 1000-44; Alternate Decay Heat Removal; Revision 18
- Work Order 1044112; Installation and removal of the Scorpion Platform; Task 23
- OU-AA-103; Shutdown Safety Management Program; Revision 8
- OU-QC-104; Shutdown Safety Management Program Quad Cities Annex; Revision 9
- ER-AA-600-1043; Shutdown Risk Management; Revision 4
- LER 265/09-001; Failure of Common Unit EDG Auxiliaries to Transfer Power Sources to Support Unit 2; report dated 06/09/2009

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
ALARA	As-Low-As-Is-Reasonably-Achievable
ASD	Adjustable Speed Driver
ASME	American Society of Mechanical Engineers
ATCU	Automated TIP Control Unit
CAP	Corrective Action Program
CFR	Code of Federal Regulations
EDG	Emergency Diesel Generator
ESFAS	Engineered Safety Feature Actuation System
GE	General Electric
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Issue Report
ISI	Inservice Inspection
LER	Licensee Event Report
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
MG	Motor-Generator
MWe	Megawatts Electric
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
NSO	Nuclear Station Operator
OBE	Operating Basis Earthquake
OOS	Out-of-Service
OSP	Outage Safety Plan
PARS	Publicly Available Records
PI	Performance Indicator
PM	Post-Maintenance
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RRCS	Reactor Recirculation Control System
RWP	Radiation Work Permit
SDP	Significance Determination Process
SSC	Structures, Systems, and Components
TIP	Traversing Incore Probe
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
Vdc	Volts Direct Current
WO	Work Order