July 29, 2005

Mr. Christopher M. Crane
President and Chief Nuclear Officer
Exelon Nuclear
Exelon Generation Company, LLC
Quad Cities Nuclear Power Station
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000254/2005003;
05000265/2005003

Dear Mr. Crane:

On June 30, 2005, 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 findings which were discussed on July 13, 2005, with Mr. Tulon and other members of your staff.

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

Based on the results of this inspection, the inspectors identified five issues of very low safety significance (Green). Four of these issues involve violations of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into the licensee's corrective program, the NRC is treating these findings and issues as Non-Cited Violations in accordance with Section V1.A.1 of the NRC's Enforcement Policy.

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

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be 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 05000254/2005003; 05000265/2005003
w/Attachment: Supplemental Information

cc w/encl: Site Vice President - Quad Cities Nuclear Power Station
Plant Manager - Quad Cities Nuclear Power Station
Regulatory Assurance Manager - Quad Cities Nuclear Power Station
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional
Operating Group
Vice President - Mid-West Operations Support
Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional
Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional
Operating Group
Document Control Desk - Licensing
Vice President - Law and Regulatory Affairs
Mid American Energy Company
Assistant Attorney General
Illinois Emergency Management Agency
State Liaison Officer, State of Illinois
State Liaison Officer, State of Iowa
Chairman, Illinois Commerce Commission
D. Tubbs, Manager of Nuclear
MidAmerican Energy Company

DOCUMENT NAME: G:\quad\ML052130446.wpd

To receive a copy of this document, indicate in the box:"C" = Copy without enclosure "**E**"= Copy with enclosure"**N**"= No copy

OFFICE	RIII							
NAME	MRing							
DATE	0729/05							

OFFICIAL RECORD COPY

ADAMS Distribution:
GYS
LWR
RidsNrrDipmIipb
GEG
KGO
KKB
CAA1
C. Pederson, DRS (hard copy - IR's only)
DRPIII
DRSIII
PLB1
JRK1
ROPreports@nrc.gov (inspection reports, final SDP letters, any letter with an IR number)

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	05000254/2005003; 05000265/2005003
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	April 1 through June 30, 2005
Inspectors:	K. Stoedter, Senior Resident Inspector M. Kurth, Resident Inspector R. Baker, Resident Inspector - Duane Arnold A. Barker, Project Engineer J. House, Senior Radiation Specialist D. Jones, Reactor Inspector D. Melendez-Colon, Reactor Engineer S. Sheldon, Reactor Inspector D. Tharp, Resident Inspector - Clinton R. Ganser, Illinois Emergency Management Agency
Observers:	M. Cashatt, BWR Instructor - Technical Training Center R. Lukes, Nuclear Safety Professional
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000254/2005003, 05000265/2005003; 04/01/2005-06/30/2005; Quad Cities Nuclear Power Station, Units 1 & 2; Operability Evaluations, Identification and Resolution of Problems, and Event Followup.

This report covers a 3-month period of baseline resident inspection, announced baseline inspections on the inservice inspection program and radiation protection, and the completion of Temporary Instruction 2515/163. The inspections were conducted by Region III inspectors and the resident inspectors. Five Green findings associated with four non-cited violations were identified. 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 3, dated July 2000.

A. <u>Inspector-Identified and Self-Revealed Findings</u>

Cornerstone: Initiating Events

- Green. A self-revealing finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, were identified on March 27, 2005, due to the failure to implement effective corrective actions following the overloading of an electrical bus. This resulted in an overload of an electrical bus during the Unit 1 refueling outage and the loss of the Unit 1 125 Volt battery chargers, the control room emergency ventilation system, and one half of the fuel pool cooling system.

  This finding was more than minor because the ineffective corrective actions resulted in the procedures used to monitor loading on cross connected electrical buses being inadequate. This finding was of very low safety significance since the loads supplied by the Unit 1 battery chargers could be supplied from an alternate source, the fuel pool cooling loss did not result in a significant increase in temperatures, the Unit 1 reactor vessel water level was greater than 23 feet above the vessel flange, and the likelihood of a fire or toxic gas release occurring coincident with the loss of the electrical bus was very low. Corrective actions for this issue included reviewing all procedures which allowed buses to be cross connected to ensure that specific information regarding the prevention of bus overloading was included, and establishing positive controls for cross connected equipment within the applicable procedures. (Section 4OA3.1)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a finding of very low safety significance in May 2005 while reviewing an evaluation used to justify the continued operability of commercial grade brass fittings installed on safety-related equipment. The primary cause of this finding was related to the cross-cutting area of Human Performance, in that, engineering personnel had information regarding the fact that 5 out of 14 fitting batches were unable to be tested. However, information which justified the continued operability of the untested fittings was not included in the associated operability evaluation.

This finding was more than minor because, if left uncorrected, the station could reach inappropriate conclusions regarding the continued operability of equipment important to safety. The finding was of very low safety significance because none of the safety-related equipment was determined to be inoperable. No violations of NRC requirements occurred since operability evaluations were not required by NRC regulations. (Section 1R15)

- Green. The inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, due to the failure to effectively implement the requirements contained in QCOS 1600-32, "Drywell/Torus Closeout," in May and June 2005. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution, in that, the inspectors had informed the licensee of previous deficiencies in the station's processes used to ensure that foreign material was not left in the drywell following the completion of a refueling or maintenance outage. However, it appeared that little action had been taken to address the inspectors' concerns.

  This finding was more than minor because if left uncorrected, the continued accumulation of foreign material in the drywell could lead to a condition in which material could block the emergency core cooling suction strainers, ventilation, spherical junction drain lines, or motor vents during normal operation or accident conditions. This finding was of very low safety significance because the material left in the drywell did not result in an actual loss of safety function. Corrective actions for this issue included the removal of material from the drywell and assigning outage work control personnel activities to ensure that future drywell and torus closeout activities effectively removed all foreign material prior to commencing startup activities. (Section 4OA2.4)

Cornerstone: Barrier Integrity

- Green. A finding of very low safety significance was identified on April 26, 2005, due to the unacceptable preconditioning of the Unit 1 main steam isolation valves prior to performing as-found stroke time testing. This finding resulted in a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI. The primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution, in that, licensee personnel had previous operating experience which indicated that performing maintenance prior to conducting main steam isolation valve as-found stroke time testing was not appropriate. The inspectors determined that although the licensee took actions to address the specific preconditioning concern, the actions taken to address the extent of condition were not timely.

  This issue was more than minor because it was associated with attributes of the barrier integrity and mitigating systems cornerstones and impacted the objectives of both cornerstones. The issue was of very low safety significance because the issue involved inadequate testing which did not degrade the ability of the main steam isolation valves to perform their function. Corrective actions for this issue included revising the normal unit shutdown procedure to ensure that the main steam isolation valve stroke time test was performed when required, revising the outage planning procedure to include steps which ensured that preconditioning issues were identified and addressed as part of the outage planning and scheduling processes, revising the outage scheduling template to ensure that the as-found main steam isolation valve stroke time testing could not be rescheduled, and performing an extent of condition review. (Section 4OA2.3)

- Green. A finding of very low safety significance and a Non-Cited Violation of Technical Specification 3.4.3 were identified on April 5, 2005, due to the inability of three main steam safety valves to actuate within plus or minus one percent of the setpoint.

  This finding was more than minor because if left uncorrected, the failure to ensure that the main steam safety valves actuated when required put the licensee at risk for exceeding their vessel overpressure limits following an accident or an anticipated transient without scram. This finding was of very low safety significance because the valves would have actuated within the plus or minus three percent assumed by the licensee’s current vessel overpressure analysis and allowed by the American Society of Mechanical Engineers Code. Corrective actions for this issue included the installation of new main steam safety valves and submitting a license amendment to change the main steam safety valve operating tolerance. (Section 4OA3.2)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period approximately 10 days into refueling outage 18. Unit 1 commenced startup activities on April 17, 2005. While preparing to synchronize the turbine with the electrical grid, operations personnel received an unexpected trip of the main turbine and generator. Engineering and maintenance personnel performed extensive troubleshooting and determined that the trip occurred due to a faulty backup reverse power relay. At 2:46 a.m. on April 19, 2005, operations personnel successfully synchronized the generator with the electrical grid. Approximately 1.5 hours later, operations personnel tripped the main turbine due to high bearing vibrations and a suspected malfunction of the electrohydraulic control system. Subsequent troubleshooting was unable to determine the cause of the malfunction. Operations personnel performed a final synchronization of Unit 1 to the electrical grid at 8:18 p.m. on April 19, 2005.

Engineering and operations personnel conducted Unit 1 power ascension activities from April 18 through April 21, 2005. On the evening of April 21, Unit 1 achieved 85 percent power. Unit 1 operated at this power level until May 28. From May 28 through June 2, 2005, the licensee conducted a planned steam dryer replacement outage. Following the dryer replacement, station personnel conducted three days of steam dryer testing. During the dryer testing, the licensee identified that the new steam dryer was unable to meet all of the test acceptance criteria at 85 percent power. As a result, Unit 1 operated at 82 percent power upon test completion. On June 8, 2005, the licensee completed evaluating the steam dryer test data which allowed Unit 1 reactor power to be increased to 85 percent. Unit 1 remained at this power level until June 16 when a reactor scram was received due to a high reactor pressure condition. The licensee determined that the high pressure condition was caused by a failure in the electrohydraulic control system. Unit 1 returned to power on June 19, 2005. After completing additional steam dryer testing, Unit 1 power levels remained at 85 percent for the remainder of the inspection period.

Unit 2 began the inspection period operating at 85 percent power. Unit 2 power levels were restricted to this level pending the resolution of previously identified extended power uprate concerns. On May 9, 2005, licensee personnel shut down Unit 2 to replace the steam dryer. Approximately nine days later, Unit 2 was synchronized to the electrical grid. From May 16 through 21, 2005, the licensee conducted multiple control rod pattern adjustments, power increases, and steam dryer performance tests as part of the power ascension process. Following this testing, the licensee reduced Unit 2 reactor power to 95 percent to ensure that plant operations remained within the steam dryer testing acceptance criteria until further analysis could be completed. On June 22, 2005, the licensee completed the dryer analysis which allowed Unit 2 to operate at 98 percent power. Unit 2 operated at this power level for the remainder of the inspection period.

1. REACTOR SAFETY

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

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors assessed the licensee's readiness for warm weather conditions by conducting detailed inspections on the following equipment:

- Unit 1 control rod drive system; and
- Units 1 and 2 turbine building closed cooling water systems.

The inspectors selected the Unit 1 control rod drive system as an inspection sample because this system was listed as an exception on the licensee's summer readiness checklist. In addition, the licensee believed that the degraded condition of both Unit 1 control rod drive pumps could have challenged continued unit operation. The turbine building closed cooling water systems were chosen for the second inspection sample due to material condition issues which had resulted in accumulated chemical deposits on the heat exchanger outlet valves.

The inspectors reviewed the Updated Final Safety Analysis Report, the licensee's seasonal readiness procedures, previously initiated issue reports, cause determinations, and trending evaluation packages to assess the licensee's actions in resolving the material condition issues associated with both of the inspection samples. The inspectors compared this information to the licensee's seasonal readiness exceptions list, system readiness reports, and open maintenance work requests to ensure that the material condition of the systems listed above were being evaluated against the continued ability of these systems to perform their functions. This inspection represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed partial walkdowns of the following risk-significant mitigating systems equipment during times when the equipment was of increased importance due to redundant systems or other equipment being unavailable:

- Unit 2 residual heat removal and residual heat removal service water while being relied upon to provide shutdown cooling; and

- Unit 2 control rod drive system during a time when the 1A control rod drive pump was degraded and the 1B control rod drive pump was out of service.

The inspectors utilized the valve and breaker checklists listed at the end of this report to verify that the components were properly positioned and that support systems were lined up as needed. The inspectors examined the material condition of the components and observed equipment operating parameters to verify that there were no obvious deficiencies. The inspectors reviewed outstanding work orders and issue reports to verify that those documents did not reveal issues that could affect the equipment inspected. The inspectors also used the information in the appropriate sections of the Updated Final Safety Analysis Report to determine the functional requirements of the systems. This activity represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed routine walk downs of accessible portions of the following fire zones:

- Fire Zone 1.1.1.2 - Unit 1 Reactor Building Ground Floor Elevation 595 Feet;
- Fire Zone 1.1.1.3 - Unit 1 Reactor Building Mezzanine Level;
- Fire Zone 1.1.1.4 - Unit 1 Reactor Building Third Floor;
- Fire Zone 1.1.1.5 - Unit 1 Reactor Building Standby Gas Treatment Floor East;
- Fire Zone 1.1.1.5 - Unit 1 Reactor Building Standby Gas Treatment Floor West;
- Fire Zone 5.0 - Safe Shutdown Makeup Pump Room;
- Fire Zone 8.2.6.A - Unit 1 Turbine Building Reactor Feed Pumps;
- Fire Zone 8.2.6.E - Unit 2 Turbine Building Reactor Feed Pumps;
- Fire Zone 8.2.7.A - Unit 1 Turbine Building Hydrogen Seal Oil Area;
- Fire Zone 8.2.8.E - Unit 1 Main Turbine Floor (Outside Shield Wall);
- Fire Zone 8.2.8.E - Unit 2 Main Turbine Floor (Outside Shield Wall);
- Fire Zone 9.1 - Unit 1 Turbine Building Diesel Generator Room; and
- Fire Zone 9.2 - Unit 2 Turbine Building Diesel Generator Room.

The inspectors verified that transient combustibles were controlled in accordance with the licensee's procedures. The inspectors observed the condition and placement of fire extinguishers and hoses against the Pre-Fire Plan fire zone maps. The physical condition of accessible passive fire protection features such as fire doors, fire dampers, fire barriers, fire zone penetration seals, and fire retardant structural steel coatings were also inspected to verify proper installation and physical condition. Lastly, the inspectors reviewed Issue Reports 336678 and 337623 which were generated based on the results of this inspection. These inspections represented the completion of thirteen quarterly inspection samples.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

.1 Review of External Flooding Protection Barriers and Procedures

a. Inspection Scope

The inspectors conducted an annual review of the licensee's external flooding procedures and analyses. The review included verifying that actions specified within the licensee's procedures were consistent with design bases documents, that the actions could be accomplished within the time specified in the documents, and that flooding-related equipment was readily available, appropriately labeled, and in good material condition. The inspectors reviewed completed maintenance work documents to ensure that preventive maintenance tasks on external flooding related equipment were completed as required. The inspectors also conducted a search of the licensee's corrective action database to verify that flooding problems entered into the corrective action program were adequately addressed. This represented the completion of one external flooding inspection sample.

b. Findings

No findings of significance were identified.

.2 Review of Internal Flooding Features for Risk-Significant Structures, Systems, and Components

a. Inspection Scope

The inspectors performed a review of potential internal flooding concerns for the following issues:

- Potential for Flooding Emergency Core Cooling System Corner Rooms due to Flooding of the Torus Basement Areas; and
- Potential for Flooding Residual Heat Removal Service Water Vaults During Maintenance Which Required Removal of the Bulkhead Doors.

The inspections focused on verifying that flooding mitigation plans and equipment were maintained as required and that the plans were consistent with design requirements and risk analysis assumptions. The inspection activities included, but were not limited to, visually inspecting the installed design measures, seals, and drain systems to verify their adequacy, reviewing the results of flooding related equipment surveillance tests to ensure that acceptance criteria were met, and reviewing the flooding and surveillance procedures for technical adequacy. Inspection activities also focused on verifying that flood mitigation plans, equipment design requirements, and risk analysis assumptions accounted for recent guidance provided in NRC Information Notice 2005-11, dated

May 6, 2005. The inspectors searched the licensee's corrective action database to verify that internal flooding protection issues had been entered into the licensee's corrective action program for resolution. This review represented the completion of two internal flooding inspection samples.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Piping Systems Inservice Inspection

a. Inspection Scope

From March 28 to April 1, 2005, the inspectors conducted a review of the implementation of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries during the Unit 1 outage (Q1R18). The inspectors selected the American Society of Mechanical Engineers Boiler and Pressure Vessel Code, Section XI, required examinations and Code components in order of risk priority as identified in Section 71111.08-03 of Inspection Procedure 71111.08, "Inservice Inspection Activities," based upon the inservice inspection activities available for review during the onsite inspection period.

The inspector conducted an on-site review of the following types of nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers Code, Section XI and Section V, requirements and to verify that indications and defects (if present) were dispositioned in accordance with the American Society of Mechanical Engineers Code, Section XI requirements. Specifically, the inspectors observed/reviewed the following examinations:

- Ultrasonic examination of an elbow-to-pipe weld (weld 02AS-S4), feedwater "B" inlet;
- Radiographic examination film of welds 1, 3, and 12 performed on a safe shutdown makeup pump pipe (1-2904-4"-B) replacement; and
- Automated ultrasonic examination of reactor core shroud weld VSC2-323.

The inspectors reviewed an examination with recordable indications that was accepted for continued service to verify that the licensee's acceptance was in accordance with the American Society of Mechanical Engineers Code or an NRC approved alternative. Specifically, the inspector reviewed the following record:

- Ultrasonic examination records (Q1R18-052) for residual heat removal elbow-flange weld (1006B-4) performed on March 15, 2005. A recordable indication was dispositioned as inside diameter geometry-counterbore.

The inspectors reviewed completed pressure boundary welds for American Society of Mechanical Engineers Code Class 1 or 2 systems to verify that the welding process and welding examinations were performed in accordance with American Society of Mechanical Engineers Code requirements or an NRC approved alternative. Specifically, the inspectors reviewed welds associated with the following work activities:

- Safe shutdown makeup pump discharge pipe (1-2905-4"-B) rerouting replacement (Welds 1 through 12).

The inspector performed a review of inservice inspection-related problems that were identified by the licensee and entered into the corrective action program. Additionally, the inspector's review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspector evaluated the threshold for identifying issues through interviews with licensee staff and a review of licensee actions to incorporate lessons learned from industry issues related to the inservice inspection program. The inspector performed these reviews to ensure compliance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements.

The reviews as discussed above counted as one inspection sample.

b. <u>Findings</u>

No findings of significance were identified.

1R12 <u>Maintenance Implementation</u> (71111.12)

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee's handling of performance issues and the associated implementation of the Maintenance Rule (10 CFR 50.65) to evaluate maintenance effectiveness for the systems and structures listed below. These inspection items were selected based on them being designated as risk significant under the Maintenance Rule, being in increased monitoring (Maintenance Rule category a(1) group), or due to an inspector identified issue or problem that potentially impacted work practices, reliability, or common cause failures:

- Containment; and
- Battery Room Ventilation.

The inspectors review included an examination of specific system or structural issues, an evaluation of maintenance rule performance criteria, maintenance work practices, common cause issues, extent of condition reviews, and trending of key parameters. The inspectors also reviewed the licensee's maintenance rule scoping, goal setting, performance monitoring, functional failure determinations, and current equipment performance status. This review represented the completion of two inspection samples.

b. Findings

During a review of the March 2005 Quarterly System Health Indicators, the inspectors noticed that the battery room ventilation system for both units was identified as being at risk of being classified as maintenance rule (a)(1) due to repetitive failures of the heating elements. The inspectors chose this system for further evaluation due to identifying previous maintenance rule issues on the same system.

History of Heater Element Failures

In April 1998, the licensee began experiencing an increase in the number of battery room ventilation heater failures. The licensee evaluated this issue and created a preventive maintenance task to check the current draw of the heater elements once per year. By January 2000, the battery room ventilation heater elements had experienced repetitive maintenance rule functional failures. This resulted in the battery room ventilation system being classified as maintenance rule (a)(1) on May 18, 2000. Based upon information provided by the heater vendor, the licensee believed that the failures were caused by uneven air flow through the elements and low air velocities. As a result, the licensee modified the Unit 1 battery room ventilation system on June 15, 2001, in an effort to reduce the number of heating element failures. The Unit 2 system was not modified as the licensee believed that the system performance was adequate.

During a review of issue reports, the inspectors determined that the Unit 1 and Unit 2 battery room ventilation system heaters were found degraded in November 2002. In response to the November 2002 heater degradation, the system engineer performed a calculation which showed that the battery room ventilation system was able to perform its safety function as long as the current draw from the heaters was 12 amps or greater. As a result, the November 2002 heater issues were not classified as maintenance rule functional failures.

On October 28, 2003, operations personnel initiated Issue Report 183554 when they discovered that the battery room ventilation heater current for both units was significantly less than 12 amps. The licensee classified this condition as a maintenance rule functional failure. The inspectors reviewed the licensee’s apparent cause report and agreed that the heating elements were failing due to a design issue. This conclusion was based upon vendor information which indicated that the installed heaters were not the correct type. The licensee planned to correct this condition by installing the appropriate heaters. In the interim, the licensee increased the preventive maintenance task frequency to twice per year.

Review of Activities Associated with the Battery Room Ventilation Modifications

The inspectors reviewed corrective action program assignments to determine the status of the battery room modifications. The inspectors determined that engineering personnel were given an assignment to initiate and present a battery room ventilation system design change to the Plant Health Subcommittee by December 11, 2003. The inspectors confirmed that this assignment was completed by the required date. The Plant Health Subcommittee assigned the design change a rating of 12.

On February 3, 2005, operations personnel initiated Issue Report 297568 to document that the Unit 1 battery room heaters were not drawing enough current. The licensee classified this issue as a maintenance preventable functional failure. In addition, the licensee conducted a functional failure cause evaluation and determined that the failure had occurred because the modification approved by the Plant Health Subcommittee in December 2003 had not been installed in a timely manner.

The licensee initiated Issue Report 314083 to document the untimely corrective actions. The system engineer determined that the corrective actions were untimely because the modification rating assigned by the Plant Health Subcommittee was so low that the modification would have never been installed. The licensee developed three actions in response to this discovery. First, the battery room ventilation modification was given a ranking high enough to ensure that the modification would be installed. Second, a service request was submitted to change the preventive maintenance task frequency from semi-annually to quarterly. Third, engineering personnel were assigned an action to consider changing ER-AA-2001, "Plant Health Committee," such that modifications for systems that are at risk of being classified as maintenance rule (a)(1) were given a higher rank.

The inspectors discussed the modification's initial low ranking with a member of the Plant Health Subcommittee. The inspectors explained that an action which only required engineering personnel to consider changing ER-AA-2001 may not appropriate since a decision could be made to not change the procedure. The inspectors explained that any time a modification was needed to correct a condition adverse to quality, the Plant Health Subcommittee was required by 10 CFR Part 50, Appendix B, Criterion XVI, to give the modification a ranking which ensured the condition adverse to quality was promptly corrected. The inspectors believed that a change needed to be made to ER-AA-2001 to incorporate the Appendix B information. At the conclusion of the inspection, the Plant Health Subcommittee member was evaluating the need for additional changes to ER-AA-2001. In addition, it was not clear whether other modifications needed to correct conditions adverse to quality were given the appropriate rating to ensure the conditions were corrected in a timely manner. Therefore, the inspectors considered this item to be unresolved pending a review of the Plant Health Committee's modification list to ensure that conditions adverse to quality were being corrected in a timely manner **(Unresolved Item (URI) 05000254/2005003-01; 05000265/2005003-01)**.

<u>Review of Battery Room Ventilation System Heater Currents</u>

The inspectors reviewed issue reports generated between October 2003 and February 2005 to determine whether additional battery room ventilation heater current problems had been identified. The inspectors found that operations personnel had initiated Issue Reports 265389 and 266803 to document that the Unit 1 and Unit 2 battery room ventilation heaters failed to draw more than 15 amps. The system engineer reviewed these issue reports and concluded that neither report constituted a maintenance rule functional failure. This conclusion was based upon information provided in Engineering Change 342493, "Evaluate Necessary Number of Heaters for the Battery Room Ventilation System to Maintain Batteries Above 65 Degree Design Limit."

The inspectors reviewed Engineering Change 342493 and found that some of the assumptions may not be appropriate. Specifically, the engineering change assumed an outside air temperature of -10 degrees for Unit 1 and 0 degrees for Unit 2. The inspectors consulted the Updated Final Safety Analysis Report and determined that the minimum historical outside air temperature for Quad Cities Station was -26 degrees. The inspectors questioned a systems engineering supervisor and learned that another section of the Updated Final Safety Analysis Report stated that the battery room ventilation system was designed to operate with a minimum outside air temperature of -6 degrees. Based upon this information, the inspectors questioned the supervisor regarding three areas:

- Why the temperatures assumed in the engineering change differed from the Updated Final Safety Analysis Report;
- Whether the initial classification of the October 2004 issue reports as non-maintenance rule functional failures was appropriate based upon the fact that the results of the engineering change may be invalid; and
- Was the battery room ventilation system inoperable during the times when outside air temperatures were less than -6 degrees.

The engineering supervisor initiated Issue Reports 345946 and 346051 in response to the inspectors concerns. However, licensee personnel were unable to fully address the inspectors concerns before the end of the inspection period. The inspectors concluded that issues regarding the adequacy of Engineering Change 342493, and the potential impacts on the maintenance rule classification of the battery room ventilation system, should be classified as unresolved pending a review of the licensee's subsequent actions **(URI 05000254/2005003-02; 05000265/2005003-02)**.

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

a. Inspection Scope

The inspectors reviewed the documents listed in the "List of Documents Reviewed" section of this report to determine if the risk associated with the listed activities agreed with the results provided by the licensee's risk assessment tool. In each case, the inspectors conducted walkdowns to ensure that redundant mitigating systems and/or barrier integrity equipment credited by the licensee's risk assessment remained available. When compensatory actions were required, the inspectors conducted plant inspections to validate that the compensatory actions were appropriately implemented. The inspectors also discussed emergent work activities with the shift manager and work week manager to ensure that these additional activities did not change the risk assessment results.

- Review of changes to online and shutdown risk due to emergent reports that the post loss of coolant accident switchyard voltage would be below required levels (various dates);

- Work Week May 23 - 28, 2005, including routine maintenance and surveillance and emergent work on the Unit 1 glycol coolers and the 1A control room ventilation air handling unit;
- Work Week May 31 - June 4, 2005, including routine Unit 2 maintenance and surveillance activities, Unit 1 steam dryer replacement outage activities, and emergent work on the Unit 1 X-2 interlock;
- Work Week June 13-19, 2005, including routine maintenance on the Unit 1 residual heat removal system, the 2A pumpback compressor, the Unit 2 station blackout diesel generator, and scheduled surveillances on the Unit 2 reactor core isolation cooling system; and
- Work Week June 27 through July 3, 2005, including modifications to the B fire pump, and routine maintenance on the Unit 2 250V battery charger, the Unit 1 emergency diesel generator air compressors, the Unit 1A reactor water cleanup demineralizer, the 2B pumpback compressor, and the Unit 2 instrument air compressor.

This inspection represented the completion of five inspection samples.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Evolutions (71111.14)

a. Inspection Scope

The inspectors monitored the licensee's performance of troubleshooting activities following the unexpected loss of electrical buses 18 and 19 on March 27, 2005. The inspectors conducted this inspection using the non-routine evolutions procedure since it was unclear whether the loss of the electrical buses was caused by an equipment problem or a personnel error. The inspectors attended meetings to monitor the licensee's troubleshooting progress and observed actual troubleshooting activities in the field. As part of the inspection effort, the inspectors compared the licensee's breaker testing procedure to industry guidance contained in several Nuclear Maintenance Assistance Center standards to ensure that the licensee's procedures would appropriately identify any potential breaker issues which could have contributed to the electrical bus loss. This review represented the completion of one inspection sample.

b. Findings

No findings of significance were identified with the troubleshooting efforts. However, the loss of the electrical buses resulted in the submittal of a Licensee Event Report (LER). Additional information regarding the loss of the electrical buses can be found in Section 4OA3 of this report.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors assessed the adequacy of the following operability evaluations or issue reports associated with equipment operability issues:

- Issue Report 325253 - Shell Thinning Identified on the B Feedwater Heaters;
- Issue Report 325625 - Address Why Degraded Primary Containment Coatings Was Not a Startup Issue;
- Issue Report 328851 - Commercial Grade Brass Fittings Used in Safety-Related Applications (Operability Evaluation 328851); and
- Issue Report 340660 - 2B Standby Liquid Control System Continuity Meter Relay Needs Replaced and Replacement Not Like for Like.

The inspectors reviewed the technical adequacy of the evaluations against the Technical Specifications, Updated Final Safety Analysis Report, and other design information; determined whether compensatory measures, if needed, were taken; and determined whether the evaluations were consistent with the requirements of LS-AA-105, "Operability Determination Process," Revision 0.

In addition, the inspectors reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance. Four inspection samples were completed during this inspection period.

b. Findings

Introduction: The inspectors identified one Green finding (FIN) due to the licensee's failure to adequately address the continued operability of several brass fittings as part of Operability Evaluation 328851.

Discussion: On May 3, 2005, engineering personnel completed Operability Evaluation 328851 to address the continued operability of multiple brass fittings which had been supplied by the vendor as commercial grade rather than safety-related. The licensee identified the need for an operability evaluation following a review which showed that the fittings had been installed on multiple pieces of safety-related equipment including the standby gas treatment, scram discharge volume, and primary containment isolation systems.

In response to this issue, the licensee determined that the fittings could be dedicated for safety-related use. However, the dedication process required that a representative sample from each batch of fittings be tested to determine that the fittings were of the proper dimensions and made of the proper materials. On May 2, 2005, the licensee received Exelon Power Labs Test Report QDC-55618, Revision 1. This test report stated that the fittings tested were of the proper material. The licensee had previously determined that the fittings were of the proper dimensions. The licensee incorporated this information into Operability Evaluation 328851 to demonstrate the continued operability of the brass fittings.

In late May 2005 the inspectors performed a review of Operability Evaluation 328851. As part of this review, the inspectors spoke with the operability evaluation's author and members of the procurement engineering staff. During discussions with the procurement engineering staff, the inspectors learned that the licensee was only able to test 9 out of 14 batches of fittings. The procurement engineering staff explained that the remaining 5 batches could not be tested because all of the fittings from these batches were installed in the plant.

Based on the above information, the inspectors conducted an additional review of Operability Evaluation 328851. The inspectors concluded that the operability evaluation did not address the fact that five batches of fittings were unable to be tested. As a result, the operability evaluation did not provide a justification for the continued operability of the untested fittings. The inspectors discussed this issue with the operability evaluation's author. The author stated that he needed to talk to his supervisor regarding the need to revise the operability evaluation. Approximately one month later, the inspectors questioned the author's supervisor regarding the need to update the operability evaluation. Initially the supervisor stated that the operability evaluation did not need to be revised because the overall conclusion would not change. After additional discussions with the inspectors, the supervisor agreed to revise the operability evaluation. However, the supervisor stated that his schedule would not support revising the evaluation by the end of the week. The inspectors were concerned by this statement since the operability of safety-related equipment was required by Technical Specifications.

Due to the initial unresponsiveness by the supervisor, the inspectors also discussed the above issues with senior engineering and plant management. Following these discussions, the inspectors were informed that Issue Report 345003 was written to address the inadequate operability evaluation and that the evaluation would be revised within 24 hours. During the followup discussions regarding this issue, senior engineering management learned that several other engineering supervisors also believed that operability evaluations did not need to include contrary information if this information did not change the overall conclusion. Engineering management has taken actions to change this belief. The inspectors reviewed the revised operability evaluation and had no additional concerns.

Analysis: The inspectors concluded that the failure to ensure that Operability Evaluation 328851 contained information to justify continued operability of the untested brass fittings was more than minor. This conclusion was based upon the determination that if left uncorrected, the failure to include pertinent information in operability evaluations could result in inappropriately concluding that equipment important to safety was operable. The finding also affected the cross-cutting area of Human Performance because members of the licensee's engineering staff failed to recognize that operability evaluations needed to include engineering judgement information if it was used to justify the continued operability of equipment which was not able to proven by another method. The inspectors reviewed Appendix B to IMC 0612 and determined that this finding was required to be evaluated by the SDP as it impacted the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors assessed the significance of this finding and concluded that this finding was of low safety significance (Green) because the licensee was subsequently able to justify continued operability of the untested fittings **(FIN 05000254/2005003-03; 05000265/2005003-03)**.

Enforcement: No violation of NRC requirements occurred since operability evaluations are not required by NRC regulations.

1R16 Operator Workarounds (71111.16)

.1 Quarterly Operator Workaround Reviews

a. Inspection Scope

The inspectors assessed the operator workaround issue listed below to determine the potential effects on system functionality. During this inspection, the inspectors reviewed the technical adequacy of the applicable workaround or issue report documentation against the Updated Final Safety Analysis Report and other design information to assess whether the workaround conflicted with any design basis information. The inspectors also compared the information in abnormal or emergency operating procedures to the equipment deficiency to ensure that the operators maintained the ability to operate equipment and implement important procedures when required.

- Issue Reports 325404, 339490, and 339503 - 1B Motor Generator Set Scoop Tube Locks Up.

This review represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

.2 Cumulative Assessment of Operator Workarounds

a. Inspection Scope

The inspectors assessed the cumulative effects of all operator workarounds at the station as of May 27, 2005. The inspectors utilized the Updated Final Safety Analysis Report and the Technical Specifications to determine the function of each system impacted by an operator workaround. Once the function was determined, the inspectors reviewed the contents of corrective action documents, modification packages, and procedure changes to determine the nature of the operator workaround and future actions to resolve each deficiency. After gaining a thorough understanding of each workaround, the inspectors interviewed licensee personnel and reviewed normal, abnormal, and emergency operating procedures to determine the potential effects of each workaround on the functionality of the corresponding systems. The inspectors also performed a word search on the corrective action program database to ensure that the licensee was entering issues associated with operator workarounds into the corrective action program with the appropriate characterization and significance. This review represented the completion of one cumulative review sample.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post maintenance testing activities listed below during the inspection period:

- TIC-1144 - Unit 1 250 Volt direct current (Vdc) Battery Service Test following battery replacement;
- QCIS 0200-16 - Unit 1 Main Steam Line High Flow Transmitter Loop Calibration and Functional Test following replacement of the flow switches;
- TIC-1204 - Reactor Recirculation Pump 1B Motor Uncoupled Run following motor replacement;
- Engineering Change 347763 - Upgrade Unit 1 Electromatic Relief Valves;
- Various Post Maintenance Tests following Unit 1 Main Steam Isolation Valve Maintenance;
- Work Orders 1402968 and 1402970 - Upgrade/Replacement Components for the Unit 1 Target Rock Safety Relief Valve;
- Work Request 175575 - Troubleshoot Unexpected Reverse Power Trip of Unit 1 Main Generator; and
- QCOS 6600-06 - Diesel Generator Cooling Water Pump Flow Rate Test following maintenance on the Unit ½ Diesel Generator Cooling Water Pump.

For each post maintenance activity selected, the inspectors reviewed the Technical Specifications and Updated Final Safety Analysis Report against the maintenance work package to determine the safety function(s) that may have been affected by the maintenance. Following this review the inspectors verified that the post maintenance test activity adequately tested the safety function(s) affected by the maintenance, that acceptance criteria were consistent with licensing and design basis information, and that the procedure was properly reviewed and approved. When possible the inspectors observed the post maintenance testing activity and verified that the structure, system, or component operated as expected; test equipment used was within its required range and accuracy; jumpers and lifted leads were appropriately controlled; test results were accurate, complete, and valid; test equipment was removed after testing; and any problems identified during testing were appropriately documented. These inspections represented the completion of eight inspection samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The licensee conducted four outages during the inspection period. From March 21 through April 19, 2005, the licensee conducted Unit 1 refueling outage activities. On May 9, 2005, the licensee began activities to replace the Unit 2 steam dryer. The Unit 1 steam dryer was replaced during an outage which began on May 28,2005. Lastly, the licensee conducted a forced outage in mid-June following a Unit 1 reactor scram. Prior to the first three outages, the inspectors reviewed the outage schedule and outage risk assessment. When applicable, the inspectors observed various portions of the unit shutdown and other outage activities from the control room to verify that outage related equipment was properly aligned, that the shutdown risk and reactivity control programs were properly managed, and that the licensee had implemented decay heat removal system procedure requirements as applicable.

The inspectors performed the following activities daily:

- attended control room operator and outage management turnover meetings to verify that the current shutdown risk status was well understood and communicated;
- performed walkdowns of the main control room to observe the alignment of systems important to shutdown risk;
- performed periodic walkdowns of the turbine and reactor buildings to observe ongoing work activities; and
- reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

Additionally, the inspectors observed the following specific activities, as appropriate:

- shutdown and cooldown to a cold shutdown condition (MODE 4);
- implementation of abnormal operating procedures to address any abnormal occurrences;
- initiation of the shutdown cooling mode of the residual heat removal system;
- control rod withdrawals to criticality and portions of the plant power ascension;
- surveillance tests throughout the duration of the outage;
- troubleshooting efforts for emergent plant equipment issues;
- reactor vessel disassembly and reassembly; and
- drywell closeout.

These outage observations represented the completion of one refueling outage and three other outage samples.

b. Findings

The inspectors identified a Green finding and a Non-Cited Violation associated with the drywell closeout activities. See Section 4OA2 of this report for additional details.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed surveillance testing activities and/or reviewed completed surveillance test packages for the tests listed below:

- QCOS 0250-04 - Main Steam Isolation Valve Closure Time Test;
- QCIS 2000-02 - Drywell Equipment/Floor Drain Sump Flow Indication Calibration;
- QCOS 0500-05 - Mode Switch in Shutdown, Scram Solenoid Valves, and Scram Discharge Volume Vent and Drain Test at Shutdown;
- QCTS 0210-02 - Battery Charger Testing for Safety Related 125 Vdc and 250 Vdc Battery Chargers; and
- QCOS 1600-32 - Drywell/Torus Closeout.

The inspectors verified that the structures, systems, and components tested were capable of performing their intended safety function by comparing the surveillance procedure or acceptance criteria and results to design basis information contained in Technical Specifications, the Updated Final Safety Analysis Report, and licensee procedures. The inspectors verified that each test was performed as written, the data was complete and met the requirements of the procedure, and the test equipment range and accuracy were consistent with the application by observing the performance of the activity. Following test completion, the inspectors conducted walkdowns of the associated areas to verify that test equipment had been removed and that the system or component was returned to its normal standby configuration. These observations represented the completion of five inspection samples.

b. Findings

No findings of significance were identified. Refer to Section 4OA2 of this report for further information regarding QCOS 1600-32, "Drywell/Torus Closeout."

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 discussed performance indicators with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators in the occupational exposure cornerstone that had not been reported and reviewed. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas, and potential airborne areas in the plant. Selected work packages and radiation work permits were reviewed to determine if radiological controls including surveys, postings, air sampling data and barricades were acceptable. Work packages and radiation work permits (RWPs) included but were not limited to:

- RWP 10004490; Recirc Pump, Remove/Install Motor and Impeller; Revision 2;
- RWP 10005674; U2 Steam Dryer: Move To U2 Dryer/Separator Pit; Revision 0; and
- RWP 10004457; U1 Disassembly/Reassembly/Cavity Work/Wall Cleaning; Revision 0.

This review represented one sample.

The identified radiologically significant work areas were walked down and surveyed to determine if the prescribed radiation work permits, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. This review represented one sample.

The inspectors reviewed selected radiation work permits and associated radiological controls used to access these and other radiologically significant areas, and evaluated the work control instructions and control barriers that were specified, in order to determine if the controls and requirements provided adequate worker protection. Site Technical Specification requirements for high radiation areas and locked high radiation areas were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. The inspectors determined whether pre-job briefings emphasized to workers the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This review represented one sample.

The inspectors reviewed the licensee's job planning records and interviewed licensee representatives to determine if there were airborne radioactivity areas in the plant with a potential for individual worker internal exposures of greater than 50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance, such as high efficiency particulate filtration ventilation system operation and use of respiratory protection, were evaluated for worker protection. Work areas having a history of, or the potential for, airborne transuranic isotopes were reviewed to determine if the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. This review represented one sample.

The adequacy of the licensee's internal dose assessment process for internal exposures greater than 50 millirem committed effective dose equivalent was evaluated to ascertain whether affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures were properly assessed in accordance with licensee procedures. This review represented one sample.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within the spent fuel or other storage pools. This included discussions with cognizant licensee representatives. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, and condition reports related to the access control program to determine if identified problems were entered into the corrective action program for resolution. This review represented one sample.

Corrective action reports related to access controls and high radiation area radiological incidents (non-performance indicator occurrences identified by the licensee in high radiation areas less than 1 Rem/hour) were reviewed. Staff members were interviewed and corrective action documents were reviewed to determine if 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 Non-Cited Violations (NCVs) tracked in the corrective action system; and
- implementation/consideration of risk-significant operational experience feedback.

This review represented one sample.

The inspectors evaluated the licensee's process for problem identification, characterization and prioritization in order to determine if problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors determined whether the licensee's self-assessment activities also identified and addressed these deficiencies. This review represented one sample.

The inspectors discussed performance indicators with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone that had not been reported and reviewed. There were none. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected three jobs being performed in radiation areas, potential airborne radioactivity areas, and high radiation areas for observation of work activities that presented the greatest radiological risk to workers and included areas where radiological gradients were present. This involved work that was estimated to result in higher collective doses, and included diving operations, drywell and reactor cavity work sites, along with other selected work areas.

The inspectors reviewed radiological job requirements including radiation work permits and work procedure requirements, and attended as low as is reasonably achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to ascertain whether radiological conditions in the work area were adequately communicated to workers through pre-job briefings and radiological condition postings. This review represented one sample.

The inspectors also evaluated the adequacy of radiological controls including required radiation, contamination and airborne surveys for system breaches and entry into high radiation areas. Radiation protection job coverage which included direct visual surveillance by radiation protection technicians along with the remote monitoring and teledosimetry systems, and contamination control processes were reviewed to assess the effectiveness of worker protection from radiological exposure. This review represented one sample.

Work in high radiation areas having significant dose rate gradients was observed to assess the application of dosimetry to effectively monitor exposure to personnel, and to evaluate the adequacy of licensee controls. The inspectors observed radiation protection coverage of diving operations and selected drywell jobs, which involved controlling worker locations based on radiation survey data and real time monitoring using teledosimetry in order to maintain personnel radiological exposure ALARA. This review represented one sample.

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 reviewed the licensee's performance indicators for high risk high radiation areas, and for all very high radiation areas to determine if workers were adequately protected from radiological overexposure. Discussions were held with radiation protection management concerning high dose rate/high radiation areas and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection. This was done to determine whether any procedure modifications would have substantially reduced the effectiveness and level of worker protection. This review represented one sample.

The inspectors evaluated the controls (including Procedures RP-AB-460, "Tip Area Access Controls," Revision 0 and RP-AA-460, "Controls for High and Very High Radiation Areas," Revision 7) that were in place for special areas that had the potential to become very high radiation areas during certain plant operations. Discussions were held with radiation protection supervisors to determine how the required communications between the radiation protection group and other involved groups would occur beforehand in order to allow corresponding timely actions to properly post and control the radiation hazards. This review represented one sample.

During plant walkdowns, the posting and locking of entrances to high dose rate high radiation areas, and very high radiation areas were reviewed for adequacy. This review represented one sample.

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 protection work requirements. The inspectors also evaluated whether workers were aware of the significant radiological conditions in their workplace, the radiation work permit controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This review represented one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed 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 review represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated radiation protection technician performance with respect to radiation protection work requirements. This was done to evaluate whether the technicians were aware of the radiological conditions in their workplace, the radiation work permit 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 review represented one sample.

Radiological problem reports, which found that the cause of an event was radiation protection technician error, were reviewed 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 review represented one sample.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

Site specific trends in collective exposures and source-term measurements were reviewed to evaluate the effect of the plant's source term on worker exposure. This review represented one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

This section is supported by Inspection Report 50-254/2004-02 and 50-265/2004-02, Section 2OS2(.2), Radiological Work Planning.

The inspectors reviewed the licensee's list of work activities, ranked by estimated exposure, that were in progress and selected the five work activities of highest exposure significance. This review represented one sample.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements in order to determine if the licensee had established procedures, along with engineering and work controls, that were based on sound radiation protection principles in order to achieve occupational exposures that were ALARA. This also involved determining that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence, industry norms, or special circumstances. This review represented one sample.

The inspectors compared the results achieved, including dose rate reductions and person-rem used, with the intended dose established in the licensee's ALARA planning for these work activities. Reasons for inconsistencies between intended and actual work activity doses were evaluated. This review represented one sample.

The interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups were evaluated to identify interface problems or missing program elements. This review represented one sample.
The integration of ALARA requirements into work procedures and radiation work permit documents was evaluated to determine if the licensee's radiological job planning would reduce dose. This review represented one sample.

The inspectors compared the person-hour estimates, provided by maintenance planning and other groups to the radiation protection group, with the actual work activity time requirements in order to evaluate the accuracy of these time estimates. This review represented one sample.

Shielding requests from the radiation protection group were evaluated with respect to dose rate reduction and reduced worker exposure, along with engineering shielding responses follow-up. This review represented one sample.

The inspectors reviewed work activity planning to establish that there was consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components and piping, job scheduling, along with shielding and scaffolding installation and removal activities. This review represented one sample.

The licensee's post-job (work activity) reviews were evaluated to determine if identified problems were entered into the licensee's corrective action program for resolution. This review represented one sample.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The licensee's exposure tracking system was evaluated to determine whether the level of exposure tracking detail, exposure report timeliness, and exposure report distribution was sufficient to support control of collective exposures. Radiation work permits were reviewed to determine if they covered too many work activities to allow work activity specific exposure trends to be detected and controlled. During the conduct of exposure significant work, the inspectors evaluated if licensee management was aware of the exposure status of the work and would intervene if exposure trends increased beyond exposure estimates. This review represented one sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and ALARA Controls

a. Inspection Scope

The inspectors selected five work activities in radiation areas, potential airborne radioactivity areas, and high radiation areas for observation, emphasizing work activities that presented the greatest radiological risk to workers. Jobs that were expected to result in significant collective doses and involved potentially changing or deteriorating radiological conditions were observed. These included diving operations, reactor cavity and drywell work. The licensee's use of ALARA controls for these work activities was evaluated using the following:

- The use of engineering controls to achieve dose reductions was evaluated to determine if procedures and controls were consistent with the ALARA reviews, that sufficient shielding of radiation sources was provided for, and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding. This review represented one sample.

- Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays. This review represented one sample.

- The inspectors attended ALARA pre-job briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included observations that first-line job supervisors ensured that work activities were conducted in a dose efficient manner by minimizing work crew sizes, ensuring that workers were properly trained, and that proper tools and equipment were available when jobs started. This review represented one sample.

Radiological exposures of individuals from selected work groups were reviewed to determine if there was any significant exposure variations among workers, and to determine whether 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 review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee’s corrective action program at an appropriate level, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and corrected. Minor issues entered into the licensee’s corrective action system as a result of the inspectors’ observations are included in the inspection scope portions of this report.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors interviewed licensee personnel and reviewed licensee system health reports, common cause analyses, trending reports, quality assurance assessments, performance indicators, maintenance rule assessments, maintenance backlog lists, and corrective action program search results to identify trends which had not been recognized by the licensee and documented as part of the corrective action program.

b. Findings

No findings or trends of significance were identified.

.3 Review of Licensee Response Regarding Identified Main Steam Isolation Valve Preconditioning

a. Inspection Scope

On April 25, 2005, a programs engineer initiated Issue Report 328437 to document the potential preconditioning of the Unit 1 main steam isolation valves. The inspectors reviewed Issue Report 328437 to verify that the licensee's problem identification was complete, accurate, and timely, that the proposed corrective actions would correct the identified problem, and that extent of condition concerns were addressed. The inspectors also reviewed the licensee's dispositioning of previous operating experience from Limerick Station.

b. Issues and Findings

Introduction: One Green finding and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XI were identified due to the unacceptable preconditioning of the Unit 1 main steam isolation valves during the Unit 1 2005 refueling outage. The preconditioning resulted in the failure to perform Technical Specification required as-found stroke time testing of the Unit 1 main steam isolation valves prior to performing maintenance. Although the licensee took action to address the specific preconditioning concern, the actions taken to address the extent of condition were not timely.

Description:

Identification of Issue and Initial Response

During the March 2005 Unit 1 refueling outage, a programs engineer reviewed the outage schedule and determined that the main steam isolation valve stroke time test had been bundled with other testing that occurred after performing valve maintenance. The engineer was concerned that performing the stroke time test after the valve maintenance, instead of before, could constitute unacceptable preconditioning as discussed in NRC Inspection Manual Part 9900.

The engineer conducted a word search of the licensee's outage work control procedures using the term "preconditioning." No procedures were identified. Based upon these results, the engineer concluded that none of the outage procedures contained guidance on preconditioning issues. A similar word search of the online work control procedures identified a paragraph regarding preconditioning issues.

The engineer recommended two actions in response to the above issues. The actions included:

- A revision to the normal unit shutdown procedure to ensure that the main steam isolation valve stroke time test was performed when required; and
- A revision to the outage planning procedure to include steps which ensured that preconditioning issues were identified and addressed as part of the outage planning and scheduling process.

The licensee also took actions to ensure that the main steam isolation valves received an as-found stroke time test at the next available opportunity. The inspectors noted that an as-found test was satisfactorily performed in May 2005 and June 2005.

Preconditioning Review

The inspectors reviewed the guidance contained in NRC Inspection Manual Part 9900, "Maintenance - Preconditioning of Structures, Systems, and Components Before Determining Operability," and discussed this issue with the cognizant Office of Nuclear Reactor Regulation personnel to determine whether the licensee had unacceptably preconditioned the main steam isolation valves.

Part 9900 defined acceptable preconditioning as the alteration, variation, manipulation, or adjustment of the physical condition of a component before Technical Specification surveillance testing or American Society of Mechanical Engineers Code testing for the purpose of protecting personnel or equipment or to meet the manufacturer's recommendations. Additional information in Part 9900 included that preconditioning for the purposes of personnel protection or equipment preservation should outweigh the benefits gained by testing only in the as-found condition. The preconditioning was to be evaluated and documented in advance of the surveillance.

The inspectors also determined that stroke time testing of the main steam isolation valves was a test covered by the guidance provided in NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants." The inspectors found that Section C.1.c of Part 9900 specifically stated that influencing test outcomes by performing valve stroking, preventive maintenance, pump venting or draining, or manipulating components does not meet the intent of the as-found testing expectations described in NUREG-1482, and may be unacceptable. The inspectors concluded that the licensee had unacceptably preconditioned the main steam isolation valves because the preventive maintenance performed prior to the testing was not done to protect personnel or equipment or to meet the manufacturer's recommendations. The preconditioning was also not evaluated or documented in advance since the licensee was unaware that they were preconditioning the equipment. The inspectors also based this conclusion upon the fact that the licensee had operating experience information which, if dispositioned appropriately, should have alerted the licensee to the potential preconditioning concern.

Effectiveness of Corrective Actions

The inspectors determined that the initial corrective actions were appropriate. However, actions taken to address the potential extent of condition were not timely. The inspectors discussed the potential preconditioning issue with the programs engineer and outage work control personnel immediately after reading the issue report. The inspectors were concerned that there may be several other tests, required by Technical Specifications, that were being inappropriately preconditioned. The programs engineer informed the inspectors that he believed this was an outage issue which needed to be addressed by the outage work control and operations departments. Outage work control personnel informed the inspectors that this was an operations department issue since it was operations responsibility to identify and address preconditioning issues as part of the outage schedule development and review.

Over the next two months the inspectors continued to discuss this issue with outage work control and operations personnel. Discussions with operations personnel were delayed due to the cognizant individuals being on vacation. Although the inspectors continued to prompt both groups, neither group left the inspectors with an impression that an extent of condition review would be performed. Following discussions with the inspectors in mid-June, operations personnel agreed to review all outage (cold shutdown) tests to ensure that other tests were not unacceptably preconditioned. The inspectors determined that this action was appropriate. However, the inspectors concluded that the amount of time needed to resolve the extent of condition was excessive.

Effective Use of Operating Experience

The inspectors noted that Issue Report 328437 contained information regarding a similar preconditioning issue that occurred at Limerick Station in 2003. The inspectors discussed this information with the programs engineer and learned that Limerick personnel had distributed internal operating experience to all other Exelon plants in April 2003. The inspectors reviewed a June 2004 Nuclear Oversight report and found that Quad Cities personnel had dispositioned the Limerick operating experience report by stating that the main steam isolation valves were stroke timed prior to any maintenance that could result in preconditioning. While this was true at the time, the inspectors found that the licensee had not taken actions to ensure that the main steam isolation valve stroke time testing activities could not be moved within the outage schedule. As a result, the main steam isolation valve as-found stroke time testing activities were inappropriately moved in the Q1R18 outage schedule. The licensee planned to share the lessons learned from this issue with all other outage scheduling individuals. The licensee was also in the process of changing the outage scheduling template to ensure that tests which were required to be performed at certain times were unable to be moved within the outage schedule.

Risk Analysis and Enforcement

Analysis: The inspectors determined that the failure to perform as-found stroke time testing of the main steam isolation valves was more than minor because the failure was associated with the barrier performance attribute of the barrier integrity cornerstone, and it affected the cornerstone objective of maintaining the functionality of containment by ensuring the reliability of containment isolation structures, systems, or components. This finding was also associated with the equipment performance attribute of the mitigating systems cornerstone objective of ensuring the reliability of the power conversion system to respond to initiating events. Lastly, the inspectors determined that this finding also affected the cross-cutting area of Problem Identification and Resolution because the licensee had operating experience which indicated that performing the main steam isolation valve as-found stroke time test after performing maintenance constituted preconditioning. In addition, the licensee was slow to address the potential extent of condition impacts.

The inspectors reviewed the phase 1 SDP worksheets for this issue and determined that a phase 2 evaluation was required due to impacting two or more cornerstones. The inspectors conducted a phase 2 evaluation and concluded that this finding was of very low safety significance (Green) because the issue involved inadequate testing which did not degrade the ability of the main steam isolation valves to perform their function.

Enforcement: 10 CFR Part 50, Appendix B, Criterion XI, “Test Control,” required that a test program be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is performed in accordance with written test procedures which incorporate the requirements and acceptance criteria contained in the applicable design documents. Contrary to the above, on March 21, 2005, the licensee failed to establish a test program for stroke timing the main steam isolation valves which assured that all testing required to demonstrate that the valves would perform satisfactorily in service was conducted prior to performing maintenance activities. Because this violation was of very low safety significance, and because the issue was entered into the licensee’s corrective action program as Issue Reports 328437 and 348206, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2005003-04)**. Corrective actions for this issue included revising the normal unit shutdown procedure to ensure that the main steam isolation valve stroke time test was performed when required, revising the outage planning procedure to include steps which ensured that preconditioning issues were identified and addressed as part of the outage planning and scheduling processes, revising the outage scheduling template to ensure that the as-found main steam isolation valve stroke time testing could not be rescheduled, and performing an extent of condition review.

.4 Review of Drywell Closeout Activities

Introduction

Approximately two years ago, the inspectors conducted a drywell closeout inspection and identified a number of items which were required to be removed prior to startup. The inspectors discussed the results of their drywell tour with licensee management and stated that actions needed to be taken to improve the overall drywell cleaning and closeout activities prior to the NRC performing their closeout inspection. During this inspection period, the inspectors had several opportunities to perform drywell closeout inspections. The inspectors took these opportunities to assess the effectiveness of corrective actions taken in response to the inspectors' previous comments since foreign material left in the drywell following a refueling outage may challenge plant safety systems during accident conditions.

Inspection Scope

The inspectors conducted Unit 1 drywell closeout inspections in April and May 2005. The closeout inspections were conducted by performing a visual walkdown of all drywell elevations. Specific attention was given to areas which could not normally be reached by hand, areas obstructed by equipment, poorly lit areas, open pipes, etc. as individuals tended to leave items in these locations. The inspectors also reviewed Issue Reports 325572 and 339884 which were initiated following the inspectors' tours.

Issues and Findings

On April 17, 2005, the inspectors toured the Unit 1 drywell prior to closure after a refueling and maintenance outage. The inspectors' tour was conducted after the licensee had performed a cleanliness inspection to remove foreign material from the drywell. The inspectors found an excessive number of objects which included several abrasive cleaning pads, a sling used for supporting heavy loads, wire brushes, wire cutters, two welding blankets, two scaffold knuckles, two rubber shoes and gloves, a yellow rag, several grey duct tape pieces, nuts, bolts, and tie wraps. The licensee removed the inspector identified items. The licensee also initiated Issue Report 325572 to document the large number of items found by the inspectors. This issue report was closed to the outage lessons learned list. No further corrective actions were taken.

On May 31, 2005, the inspectors performed another Unit 1 drywell closeout inspection prior to the end of a maintenance outage. The inspectors found a face shield, a flashlight, duct tape pieces, tie wrap pieces, and a 3.5 foot piece of pipe that was approximately 2.5 inches in diameter. The licensee removed the items identified. The licensee initiated Issue Report 339884 to document the amount of debris found in the drywell. In addition, the outage work control department was assigned activities to determine the corrective actions for this issue.

Based upon the results of the 2005 drywell closeout inspections, the inspectors determined that the licensee had not effectively resolved the circumstances which led to repeated inspector identified drywell closeout deficiencies. This concerned the inspectors since the foreign material left in the drywell could potentially impact the operation of safety-related equipment following an accident. The inspectors also reviewed QCOS 1600-32, “Drywell/Torus Closeout,” and concluded that while the procedure appeared to be adequate, the licensee was not effectively implementing the procedure to ensure that the drywell was free of foreign material at the conclusion of a maintenance or refueling outage.

Analysis: The inspectors determined that the failure to adequately implement the requirements of QCOS 1600-32 was more than minor because if left uncorrected, the continued accumulation of foreign material in the drywell could lead to a condition in which the material could block the emergency core cooling suction strainers, ventilation, spherical junction drain lines, or motor vents during normal operation or accident conditions. The inspectors also concluded that this finding should be assessed using the SDP since it was associated with the operability, availability, reliability, or function of mitigating systems equipment. The inspectors completed a phase 1 analysis and determined that this finding was of very low safety significance (Green) since the debris did not result in an actual loss of safety function for any system when the debris was present in the drywell and because the debris was subsequently removed when it was found.

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, required that activities affecting quality be prescribed by documented instructions, procedures, and drawings of a type appropriate to the circumstance. In addition, the activities affecting quality shall be accomplished in accordance with these instructions, procedures, and drawings. QCOS 1600-32, “Drywell/Torus Closeout,” was the procedure used by the licensee to perform drywell closeout inspections (an activity affecting quality). Step 1.a of Attachment A to QCOS 1600-32, required that debris which could block emergency core cooling suction strainers, ventilation, spherical junction drain lines, or motor vents during normal operation or accident conditions be removed. Contrary to the above, in April and May 2005, the licensee failed to adequately implement QCOS 1600-32 such that all debris which could potentially impact the above equipment during normal operations or accident conditions was removed. The debris was only identified and removed after being found by the NRC during drywell closeout inspection activities. Because this violation was of very low safety significance, and because the issue was entered into the licensee’s corrective action program as Issue Report 339884, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2005003-05)**. Corrective actions for this issue included removing the NRC identified debris from the drywell, informing personnel of the ineffective drywell cleaning and inspections, and assigning outage work control personnel activities to ensure that future drywell closeouts identified and removed debris prior to being identified by the NRC.

4OA3 Event Followup (71153)

.1 (Closed) LER 50-254/05-002-00: Trip of Unit 1 Division I 4 kiloVolt Emergency Bus Feed to 480 VAC Emergency Buses in Both Divisions Due to Ineffective Corrective Actions.

Introduction: A self-revealing Green finding and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI were identified due to the licensee's failure to implement effective corrective actions following the overloading of an electrical bus in the late 1980's. Due to the ineffective corrective actions, the licensee's procedures for cross connecting electrical buses failed to include positive controls to prevent the buses from being overloaded.

Description: On March 27, 2005, the main feed breaker between Unit 1 4160 Volt bus 13-1 and 480 Volt bus 18 unexpectedly opened. At the time the breaker opened, Unit 1 was in a refueling outage with fuel moves in progress. Decay heat removal was provided by the fuel pool cooling system. In addition, bus 18 was supplying power to bus 19 due to ongoing maintenance on 4160 Volt bus 14-1. The opening of the main feed breaker resulted in the loss of power to multiple pieces of equipment. Specifically, power was lost to two fuel pool cooling pumps, the Unit 1 125 Vdc battery chargers, and the control room emergency ventilation equipment. The licensee was able to restore power to each piece of equipment within approximately 45 minutes.

The inspectors observed the licensee's testing of the bus 18 feed breaker following this event. The test results showed that the feed breaker opened due to exceeding the long time over current setpoint. The licensee conducted a review of the electrical loads supplied by buses 18 and 19 prior to the event and confirmed that the feed breaker opened due to experiencing an overload condition.

The inspectors reviewed the licensee's root cause analysis for this event. As part of the root cause investigation, the licensee found that similar bus losses had occurred in February 1984 and November 1987. In response to these two events, the licensee placed additional precautions in various electrical procedures to alert operations personnel to the potential for experiencing unexpected breaker openings when certain electrical buses were cross connected. However, no positive controls were put in place to ensure that the additional loading experienced when cross tying two electrical buses would not result in the inadvertent and unexpected opening of the associated bus feed breakers.

Analysis: The inspectors determined that the failure to implement effective corrective actions for the two previous bus overload events was more than minor because it resulted in the procedures used to monitor loading on cross-tied electrical equipment being inadequate.

To evaluate the risk significance of this issue with respect to Unit 1, the inspectors reviewed IMC 0609, Appendix G, Table 1, "Shutdown Operations - Boiling Water Reactor Refueling with Level Greater than 23 Feet." The inspectors determined that the loss of buses 18 and 19 resulted in the licensee's inability to meet Items III.2 and III.3 of Table 1. The inspectors referred to the list of items which required a phase 2 analysis which appeared at the bottom of page T-20 of Table 1. The inspectors confirmed that neither Item III.2 or Item III.3 required a phase 2 analysis, therefore, this finding was of very low safety significance (Green) with respect to Unit 1.

With regards to Unit 2, the inspectors and the RIII Senior Reactor Analyst determined that the initiating event cornerstone and the barrier integrity cornerstone were affected by the loss of the battery chargers. The barrier integrity cornerstone was affected because the loss of buses 18 and 19 resulted in a loss of power to the control room emergency ventilation system. The inspectors determined that the mitigating systems cornerstone was not affected because power to the loads supplied by the Unit 1 125 Vdc chargers remained available from alternate power supplies. Based upon this information, the inspectors determined that a phase 2 analysis was required due to the loss of the chargers. However, the loss of power to the control room emergency ventilation system required a phase 3 analysis since the power loss represented a finding which degraded the ability to protect the control room against smoke or a toxic atmosphere.

The inspectors referenced information provided in IMC 0609, Appendix A, Attachment 2, to complete the analysis for the battery chargers. As instructed by Attachment 2, the inspectors evaluated the loss of the battery chargers as a finding which increased the likelihood of a loss of a direct current bus special initiator. The inspectors found that the current revision of the SDP worksheets did not include a worksheet for the loss of a direct current bus; however a draft revision of the worksheets which had been benchmarked with the licensee's probabilistic risk assessment was available for internal use only. The inspectors and the senior reactor analyst used the draft worksheets to conduct a phase 2 analysis. The result was that the loss of the battery chargers was of very low safety significance (Green) since the loads supplied by the Unit 1 battery chargers could be fed from an alternate electrical supply. The senior reactor analyst conducted a qualitative phase 3 analysis to evaluate the loss of power to the control room emergency ventilation system. The analyst determined that the likelihood of a fire or a toxic release event occurring concurrent with a loss of buses 18 and 19 was low. Additionally, if that low likelihood event occurred, recovery of the control room ventilation system prior to evacuation would have been possible. Therefore, this condition was also determined to be of very low safety significance (Green).

<u>Enforcement</u>: 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, as of March 27, 2005, the licensee had failed to establish measures to assure that the conditions which led to the loss of multiple electrically cross tied buses (a condition adverse to quality) were promptly corrected. As a result, an identical electrical bus loss occurred on March 27, 2005. Because this violation was of very low safety significance, and because the issue was entered into the licensee's corrective action program as Issue Report 317820, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2005003-06; 05000265/2005003-06)**. Corrective actions for this issue included reviewing all bus cross tie procedures to ensure that specific information regarding the prevention of bus overloading conditions was included, revising procedures which did not address potential bus overloading concerns, and establishing positive controls (such as information regarding equipment that must be placed in pull to lock) for cross tied equipment within the applicable procedures.

.2 (Closed) LER 50-254/05-003-00: Three Main Steam Safety Valves Outside of Technical Specification Allowed Tolerance.

Introduction: A Green finding and a Non-Cited Violation were identified due to the failure of three main steam safety valves to actuate within plus or minus one percent of the nameplate value during as-found testing.

Description: On April 5, 2005, the licensee was informed that three main steam safety valves failed to meet as-found testing acceptance criteria. The licensee's Technical Specifications required that each main steam safety valve actuate within plus or minus one percent of the nameplate value to ensure that the vessel did not experience an overpressure condition post-accident. However, the tested valves actuated at -1.7 percent, -2.0 percent, and -2.3 percent of their respective values.

The inspectors reviewed the licensee's overpressure analyses and learned that the analyses assumed that the main steam safety valves actuated within plus or minus three percent of the name plate value rather than plus or minus one percent. The inspectors discussed this issue with regulatory assurance and engineering personnel since the inspectors had identified a similar condition approximately one year ago. The inspectors were aware that engineering personnel had performed a Monte Carlo analysis using the historic main steam safety valve test results. The analysis results were used to show that the main steam safety valves would continue to perform their safety function until the technical specification amendment to change the valve operating tolerance was submitted and approved. However, the inspectors were concerned that the amendment had not been submitted to the NRC.

The licensee explained that the NRC was currently reviewing a similar Monte Carlo analysis for Dresden Station. The licensee believed that they could apply the NRC's approval of the Dresden analysis to Quad Cities since the results of the Dresden analysis bounded the main steam safety valve performance at both stations. The inspectors informed the licensee that applying the results of the Dresden analysis to Quad Cities without informing the NRC of this intent would not be appropriate. Based upon this discussion, the licensee planned to submit additional information on this subject to the NRC. Per previous discussions between the Office of Nuclear Reactor Regulation and Exelon Corporation, the respective technical specification amendments were to be submitted within six months following the approval of the Dresden Monte Carlo analysis.

Analysis: The inspectors determined that the failure to ensure that the main steam safety valves maintained the ability to actuate within plus or minus 1 percent of the nameplate value was more than minor because it led to the continued degradation of additional main steam safety valves and put the licensee at risk for exceeding their vessel overpressure limits following an accident or an anticipated transient without scram. The inspectors also determined that this finding should be evaluated using the SDP because the finding was associated with the operability and functionality of a mitigating system. The inspectors conducted a phase 1 screening and determined that a phase 2 evaluation was needed as this finding impacted both the mitigating systems and barrier integrity cornerstones.

The inspectors used the Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 1, dated May 2, 2002, to complete the phase 2 evaluation. The actual dates of the valve failures could not be determined since these valves cannot be accessed or tested during reactor operation. Because of this, the inspectors assumed that the exposure time was greater than 30 days. For each SDP worksheet completed, the inspectors assumed that all remaining mitigating systems equipment was available. The inspectors allowed full credit for the main steam safety valve actuation since the valves would have actuated prior to reaching the nameplate value. Using these assumptions, the inspectors evaluated one core damage sequence on the anticipated transients without scram worksheet. The result of this sequence was eight points. Based on the counting rule, the overall increase in risk and safety was determined to be very low (Green).

Enforcement: Technical Specification 3.4.3 required the safety function of all 9 main steam safety valves to be operable in Modes 1, 2, and 3. To maintain operability, each safety valve was required to actuate within plus or minus one percent of the nameplate value. Technical Specification Limiting Condition for Operation 3.4.3.A stated that with one safety valve inoperable, actions must be taken to place the respective unit in Mode 3 within 12 hours and in Mode 4 within 36 hours. Contrary to the above, on April 5, 2005, the licensee was informed that three main steam safety valves would not have actuated within plus or minus one percent of the nameplate value during the operating cycle. Since the condition of the valves was unknown to the licensee during the operating cycle, actions were not taken to comply with the Technical Specification requirements. However, because this issue is of very low safety significance, and the issue was entered into the corrective action program as Issue Report 321351, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2005003-07)**. Corrective actions for this issue included installing new main steam safety valves, submitting the Quad Cities specific information to the NRC, and submitting a license amendment to change the main steam safety valve operating tolerance.

.3 (Closed) 60-Day Phone In Report (EN # 41770): Invalid Actuation During Excess Flow Check Valve Testing.

On April 15, 2005, while conducting excess flow check valve testing as part of the refueling outage activities, Unit 1 received an invalid anticipated transient without scram channel A trip signal and invalid reactor low-low water level trips on the A and C channels of the emergency core cooling system actuation circuitry. When this event occurred, the licensee was also performing the reactor pressure vessel hydrostatic test. Reactor pressure was approximately 787 psig at the time of the event. All equipment operated as expected. In addition, no pressure or level transients occurred following the invalid actuations.

The licensee subsequently determined that a leaking drain valve at an instrument rack where the excess flow check valve testing was being performed caused a slow depressurization of the high-side sensing line for level transmitters associated with anticipated transient without scram channel A and emergency core cooling system channels A and C, resulting in an erroneous level signal and the invalid actuation.

The inspectors discussed the excess flow check valve testing methodology and the test procedure adequacy with maintenance personnel. The inspectors determined that the testing methodology was appropriate. In addition, the inspectors concluded that the excess flow check valve test procedure was appropriately written and followed. Based upon this information, the inspectors determined that the invalid actuation was not caused by a performance deficiency. This event did not constitute a violation of NRC requirements since the test procedure was determined to be adequate.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R15 of this report had, as its primary cause, a human performance deficiency, in that, engineering personnel had information regarding the fact that 5 out of 14 fitting batches were unable to be tested. However, information which justified the continued operability of the untested fittings was not included in the associated operability evaluation on this subject.

.2 A finding described in Section 4OA2.3 of this report had, as its primary cause, a problem identification and resolution deficiency, in that, licensee personnel had previous operating experience which indicated that performing maintenance prior to conducting as-found stroke time testing of the main steam isolation valves was not appropriate. In addition, the licensee's extent of condition review for this issue was not timely.

.3 A finding described in Section 4OA2.4 of this report had, as its primary cause, a problem identification and resolution deficiency, in that, the inspectors had informed the licensee of previous problems regarding the thoroughness of the drywell cleaning and closeout activities. However, effective corrective actions were not implemented to prevent continued deficiencies from occurring.

4OA5 Other Activities

.1 (Closed) URI 05000254/2004002-02; 05000265/2004002-02: Extended Power Uprate Concerns.

By early 2004, Quad Cities Station had experienced three steam dryer failures. The licensee also experienced unexpected failures or degradations of multiple pieces of plant equipment due to extended power uprate implementation. Due to the number of and the nature of these problems, the inspectors opened a URI that could only be closed after the licensee demonstrated that the extended power uprate vulnerabilities had been identified and addressed and the steam dryers were replaced. Over the last 18 months, the licensee conducted numerous reviews and evaluations of the dryers and plant equipment. The results of these efforts were communicated to the NRC during numerous public meetings, conference calls, and document submittals. In addition, the licensee recently completed planned outages on each unit to address the identified equipment vulnerabilities/deficiencies and to replace both steam dryers. Based upon these actions, this item is closed.

.2 <u>(Closed) URI 05000254/2005002-02; 05000265/2005002-02</u>: Drywell Floor Drain Sump Pump 1B Degraded.

While reviewing the above issue, the inspectors determined that the method for operating the drywell floor drain sump pumps may have changed at some time in the past. Specifically, the Updated Final Safety Analysis Report described that the operation of this system was automatic. However, operations personnel maintained the sump pump discharge valves closed which prevented the sump pumps from starting automatically.

Due to the conflicting information, the inspectors opened the above URI to allow additional time to review any relevant procedures, drawings, or documents. The inspectors discussed this issue with the drywell floor drain system engineer on May 26, 2005 . The system engineer provided the inspectors with copies of the original drywell floor drain system plant drawings and operating procedures. The drawings showed that the pump discharge valves were normally closed valves. In addition, the operating procedures showed that the sump pumps could operate in an automatic or a manual mode. However, the automatic mode could only be accomplished after opening the pump discharge valves. A review of previous Updated Final Safety Analysis Report editions concluded that information on the drywell floor drain system was not included in the report until the mid-1980's or 1990's. When the information was incorporated, it appears that the information regarding the need to open the pump discharge valves prior to accomplishing automatic pump operation was inadvertently omitted. Based upon the above information, the inspectors concluded that the conflicting information in the current Updated Final Safety Analysis Report was due to an editorial error rather than a change in the method of operating the drywell floor drain system. As a result, no violations of NRC requirements occurred.

.3 <u>(Closed) URI 05000254/2005002-01; 05000265/2005002-01</u>: Appropriate Classification of Reactor Building Siding.

During a review of modifications to support replacement of the steam dryers, the inspectors encountered several modification packages which classified the reactor building siding as a non-safety related component. At the time of the inspection, the inspectors believed that the licensee’s classification of the siding may not have been appropriate since the siding formed part of the secondary containment barrier. The inspectors were presented with several pieces of information regarding the siding’s classification. However, the conclusions within these pieces of information conflicted with each other.

The inspectors provided all of the information to members of the Office of Nuclear Reactor Regulation for additional review. After reviewing the information and having discussions with individuals familiar with previously identified Quad Cities reactor building siding issues, the Office of Nuclear Reactor Regulation concluded that the licensee’s classification of the reactor building siding as non-safety related was appropriate. As a result, no violations of NRC requirements occurred.

.4 Implementation of Temporary Instruction (TI) 2515/163 - Operational Readiness of Offsite Power

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

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

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

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

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

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

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

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

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

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

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

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

The information gathered while completing this Temporary Instruction was forwarded to the Office of Nuclear Reactor Regulation for further review and evaluation.

.5 Implementation of NRC Inspection Procedure 71004 - Extended Power Uprates

a. Inspection Scope

From March to June 2005, the inspectors monitored the licensee's activities associated with the replacement of both steam dryers. The inspectors observed workers modifying the dryer and discussed the dryer design with individuals from General Electric and United States Tool and Die. After the dryers arrived at the station, the inspectors monitored the activities associated with lifting the dryer up to the refueling floor which included utilizing a new secondary containment enclosure. The inspectors reviewed activities associated with testing this new enclosure during the previous inspection period. During the associated dryer replacement outages, the inspectors observed individuals removing the old dryer and installing the new dryer via direct observation from the refueling floor or the outage control center. The inspectors also reviewed issue reports, General Electric design reports, and held discussions with multiple personnel to gain insights into the licensee's resolution of several fit-up issues identified while installing the first new dryer. Once the dryers were installed, the inspectors observed station personnel test the new dryers. These observations consisted of monitoring power ascension activities by operations personnel, the taking and evaluation of dryer and other plant data by engineering personnel, attendance at twice daily conference calls to discuss technical issues associated with the dryer testing, and independently assessing the resolution of issue reports written during the testing evolutions.

b. Findings

No findings of significance were identified.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Tulon and other members of licensee management at the conclusion of the inspection on July 13, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Baseline procedure 71111.08, with Mr. Moser and other members of your staff on April 1, 2005. The licensee confirmed that none of the potential report input discussed was considered proprietary; and

- The access control to radiologically significant areas program and the ALARA planning and controls program with Mr. T. Tulon on April 7 and May 12, 2005.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
T. Tulon, Site Vice President
R. Gideon, Plant Manager
R. Armitage, Training Manager
D. Barker, Work Control Manager
W. Beck, Regulatory Assurance Manager
D. Bucknell, Program Engineer
T. Hanley, Maintenance Manager
D. Hieggelke, Nuclear Oversight Manager
R. May, NDE Level III
K. Moser, Deputy Engineering Manager
V. Neels, Chemistry/Environ/Radwaste Manager
K. Ohr, Radiation Protection Manager
M. Perito, Operations Manager
G. Powell, ALARA Coordinator
K. Moser, Site Engineering Director
T. Wojcik, Engineering Programs Supervisor

Nuclear Regulatory Commission
G. Dick, NRR Project Manager
M. Ring, Chief, Reactor Projects Branch 1
L. Rossbach, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000254/2005003-01; 05000265/2005003-01	URI	Appropriateness of Plant Health Committee Modification Ranking Process
05000254/2005003-02; 05000265/2005003-02	URI	Battery Room Ventilation System Heater Currents
05000254/2005003-03; 05000265/2005003-03	FIN	Failure to Adequately Address the Continued Operability of Several Brass Fittings as Part of Operability Evaluation 328851

05000254/2005003-04	NCV	Failure to Ensure Test Program for Stroke Timing the Main Steam Isolation Valves was Appropriate
05000254/2005003-05	NCV	Drywell Closeout Activities
05000254/2005003-06; 05000265/2005003-06	NCV	Failure to Implement Corrective Actions for The Two Previous Bus Overload Events
05000254/2005003-07	NCV	Three Main Steam Safety Valves Outside of Technical Specification Allowed Tolerance

<u>Closed</u>

05000254/2005003-03; 05000265/2005003-03	FIN	Failure to Adequately Address the Continued Operability of Several Brass Fittings as Part of Operability Evaluation 328851
05000254/2005003-04	NCV	Failure to Ensure Test Program for Stroke Timing the Main Steam Isolation Valves was Appropriate
05000254/2005003-05	NCV	Drywell Closeout Activities
05000254/2005003-06; 05000265/2005003-06	NCV	Failure to Implement Corrective Actions for The Two Previous Bus Overload Events
05000254/2005003-07	NCV	Three Main Steam Safety Valves Outside of Technical Specification Allowed Tolerance
05000254/2005002-00	LER	Trip of Unit 1 Division I 4 kiloVolt Emergency Bus Feed to 480 VAC Emergency Buses in Both Divisions Due to Ineffective Corrective Actions
05000254/2005003-00	LER	Three Main Steam Safety Valves Outside of Technical Specification Allowed Tolerance
05000254/2004002-02; 05000265/2004002-02	URI	Extended Power Uprate Concerns
05000254/2005002-02; 05000265/2005002-02	URI	Drywell Floor Drain Sump Pump 1B Degraded
05000254/2005002-01; 05000265/2005002-01	URI	Appropriate Classification of Reactor Building Siding

Discussed

None.

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

WC-AA-107; Seasonal Readiness; Revision 1
Updated Final Safety Analysis Report
Summer of 2005 - Action Item List; dated May 14, 2005
List of Work Orders Impacting Summer Readiness
Issue Report 215777; U-1 A CRD Pump Degrading Trend; dated April 19, 2004
Issue Report 307482; 1B CRD Pump Discharge Pressure Trend; dated March 2, 2005
Issue Report 321284; Summer Readiness Deficiencies; dated April 5, 2005
Issue Report 322064; Nuclear Oversight Identified Summer Readiness Enhancements; dated April 7, 2005
Condition Report 328354; 2B CRD Pump Removed from Work Schedule with No New Work Date; dated April 25, 2005
Issue Report 142224; Reactor Vent Heating Coil Draining Issues; dated January 31, 2003
Work Order 162339; Chemical Deposits on 1A EHC Cooler TBCCW Outlet Valve; dated December 1, 2004
Work Order 162338; Chemical Deposits on 1B EHC Cooler TBCCW Outlet Valve; dated December 1, 2004
Work Order 158626; Surface Corrosion on TBCCW Pump Flanges/Hardware; dated October 22, 2004

1R04 Equipment Alignment

Open Work Requests for the Control Rod Drive System; dated June 6, 2005
QCOP 0300-33; CRD Pump Cross-Tie Operation Using Unit 2 CRD Pumps; Revision 1
QOM 2-0300-01; Unit 2 CRD Valve Checklist; Revision 10
QOM 1-0300-01; Unit 1 Control Rod Valve Checklist (Turbine Building at CRD Pumps); Revision 4
Piping and Instrumentation Diagram M-41, Sheet 4; Diagram of Control Rod Drive Hydraulic Piping; Revision K
Piping and Instrumentation Diagram M-83, Sheet 4; Diagram of Control Rod Drive Hydraulic Piping; Revision I

1R05 Fire Protection

Fire Hazards Analysis for Quad Cities Units 1 and 2
Pre-Fire Plans

1R06 Flood Protection

Updated Final Safety Analysis Report Section 3.4; Water Level (Flood) Design
Technical Requirements Manual Specification 3.7.f; Flood Protection
NRC Information Notice 2005-11; Internal Flooding/Spray-Down of Safety Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains; dated May 6, 2005
QCOA 0010-16; Flood Emergency Procedure; Revision 8
QCOP 4100-11; Using Diesel Fire Pumps Via Safe Shutdown Hose Line for Reactor Vessel Level Control or Flood Emergency Injection Source; Revision 9
QCAP 0250-06; Control of In-Plant Watertight "Submarine" Doors; Revision 7
Engineering Apparent Cause Evaluation 210972; Unit 2 Drywell Equipment Drain Sump Failed to Run; dated June 28, 2004

1R08 Inservice Inspection Activities

Issue Report 311474; QAP 0350-07; References Out of Date; Revision 4; dated March 11, 2005
Issue Report 316116; Improper PT Cleaner Batch Number Listed on NDE Reports; dated March 23, 2005
ISWT-PDI-AUT1/0/0/1, 2; Automated Inside Surface Ultrasonic Examination of Ferritic Vessel Wall Greater Than 4.0 Inches in Thickness; dated October 2001
ER-AA-335-005; Radiographic Examination; Revision 0

1R12 Maintenance Effectiveness

Work Order 325216-01; Perform IWE Preoutage/Outage Examinations; dated October 21, 2002
NRC Bulletin 96-03; Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors' dated May 6, 1996
Williams Speciality Services Report; Maintenance Inspection of Safety Related Coating Systems for Quad Cities Generating Station Refueling Outage Q1R18; dated April 4, 2005
ER-QC-330-1000; Primary Containment and Coatings Inspections; Revision 0
QCAP 0400-27; Containment Debris Material Control Program; Revision 0
Outage Scope Change Request Form 0566.0001; Torus Access Hatch Cover Needs Coating Repair; dated April 11, 2005
NRC Generic Letter 98-04; Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss of Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment; dated July 14, 1998
Issue Report 322400; Prior to Startup - Torus Access Hatch Covers Need Coating Repair; dated April 8, 2005
Issue Report 322402; Prior to Startup - Coating Deficiencies Inside Drywell and Torus; dated April 8, 2005
Exelon's Reponse to Bulletin 96-03; dated October 31, 1996
Letter SVP-98-369; Results of the Review of the NRC's Safety Evaluation of the Boiling Water Reactor Owners' Group Report, "Utility Resolution Guidance for Resolution of ECCS Suction Strainer Blockage;" dated December 18, 1998

Exelon's Response to Generic Letter 98-04; dated November 12, 1998
ER-AA-330-007; Visual Examination of Section XI Class MC Surfaces and Class CC Liners; Revision 3
ER-AA-335-018; General, VT-1, VT-1C, VT-3, and VT-3C, Visual Examination of ASME Class MC and CC Containment Surfaces and Components; Revision 2
ASTM Standard D 5163-05; Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant
Slides from Engineering Department's Presentation to the Plant Health Committee; Torus/Drywell Coatings 10-Year Plan; date unavailable
American Society of Mechanical Engineers Boiler and Pressure Vessel Code Section XI Rules for Inservice Inspection of Nuclear Power Plant Components; Subsection IWE Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants; Summer 1992 Edition
Regulatory Guide 1.54; Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants; Revision 1 July 2000
Maintenance Rule Panel Dates for Battery Room Ventilation Issues; dated May 26, 2005
Maintenance Rule Battery Room Ventilation Heater Issue Timeline; dated May 26, 2005

1R13 Maintenance Risk Assessment and Emergent Work

Engineering Change 355003; Provide Operations with Minimum Switchyard Voltage Values for Various Plant Configurations; dated April 15, 2005
Issue Report 316874; Predicted Post LOCA Switchyard Voltage Low; dated March 24, 2005
Issue Report 323640; Outage Lesson Learned - Predicted Post LOCA Switchyard Voltage Low; dated April 12, 2005
Issue Report 325267; Calculated Post LOCA Switchyard Voltage Low; dated April 15, 2005
QCOA 6000-02; Main Generator Abnormal Operation; Revision 3

1R15 Operability Evaluations

NRC Bulletin 96-03; Potential Plugging of Emergency Core Cooling Suction Strainers by Debris in Boiling Water Reactors' dated May 6, 1996
Williams Speciality Services Report; Maintenance Inspection of Safety Related Coating Systems for Quad Cities Generating Station Refueling Outage Q1R18; dated April 4, 2005
ER-QC-330-1000; Primary Containment and Coatings Inspections; Revision 0
QCAP 0400-27; Containment Debris Material Control Program; Revision 0
Outage Scope Change Request Form 0566.0001; Torus Access Hatch Cover Needs Coating Repair; dated April 11, 2005
NRC Generic Letter 98-04; Potential for Degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss of Coolant Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment; dated July 14, 1998
Issue Report 322400; Prior to Startup - Torus Access Hatch Covers Need Coating Repair; dated April 8, 2005
Issue Report 322402; Prior to Startup - Coating Deficiencies Inside Drywell and Torus; dated April 8, 2005

Exelon's Reponse to Bulletin 96-03; dated October 31, 1996
Letter SVP-98-369; Results of the Review of the NRC's Safety Evaluation of the Boiling Water Reactor Owners' Group Report, "Utility Resolution Guidance for Resolution of ECCS Suction Strainer Blockage;" dated December 18, 1998
Exelon's Response to Generic Letter 98-04; dated November 12, 1998
ER-AA-330-007; Visual Examination of Section XI Class MC Surfaces and Class CC Liners; Revision 3
ER-AA-335-018; General, VT-1, VT-1C, VT-3, and VT-3C, Visual Examination of ASME Class MC and CC Containment Surfaces and Components; Revision 2
ASTM Standard D 5163-05; Establishing Procedures to Monitor the Performance of Coating Service Level I Coating Systems in an Operating Nuclear Power Plant
Work Request 179684; SBLC Continuity Meter Relay Needs Replaced; dated May 2005

1R16 Operator Workarounds

Issue Report 340236; Scoop Tube Lockup to be Considered for Operator Workaround/Operator Challenge List; dated June 1, 2005

1R19 Post Maintenance Testing

Engineering Change 345323; Main steam line flow switch replacement; Revisions 0 and 1
Work Order 671754; Main Steam Line Flow Switch Replacement for Engineering Change 345323
Work Order 793634; 1B Recirculation Motor Generator Set Field Breaker Troubleshooting; dated April 12, 2005
Issue Report 323751; Prior to Startup - 1B Recirc Motor Generator Field Breaker Did Not Trip; dated April 12, 2005
QCOS 0250-08; Main Steam Isolation Valve Fail Safe Test; dated April 13, 2005
QCOS 4700-02; Inboard Main Steam Isolation Valve and Target Rock Valve Pneumatic System Leak Check; dated April 12, 2005
QCOS 0250-09; Main Steam Isolation Valve Solenoid Test; dated April 12, 2005
Issue Report 175125; 1-0590-102F Reactor Protection System Relay Did Not Open During 2B Outboard Main Steam Isolation Valve Testing; dated April 13, 2005
Outage Scope Change Request Form 0575.0001; 2C Outboard Main Steam Isolation Valve Limit Switch is Bent; dated April 13, 2005
Engineering Change 350693; Evaluation of Vibration Endurance Testing of the Target Rock Valve and Associated Changes to Internals; Revision 0
Work Order 1402968; Special Tolerances for the Target Rock Safety Relief Valve Spring; dated January 12, 2005
Work Order 1402970; Target Rock Safety Relief Valve Bellows Cap Electrolyzed with Chrome; dated January 26, 2005
Engineering Change 347763; Remove Actuator Tieback Supports on Unit 1 Electromatic Relief Valves and Upgrade Actuators and Drain Line Flanges, Revision 0
QCOS 0250-01; Main Steam Isolation Valve Closure Scram Sensor Channel Functional Test; Revision 19
TIC-1144; Service Test Procedure for the New Unit 1 250 Volt Safety Related Battery

1R22 Surveillance Testing

Issue Report 340591; Unit 1 Drywell Airlock Leakage Indication Exceeds Technical Specification Administrative Limits; dated June 2, 2005
Issue Report 340898; Unit 1 Airlock Inner Door Gasket Deformed Causing Local Leak Rate Testing Failure; dated June 3, 2005
QCOS 0500-05; Mode Switch in Shutdown, Scram Solenoid Valves, and Scram Discharge Volume Vent and Drain Test at Shutdown; dated April 16 and 17, 2005
Issue Report 326218; During Q1R18 Control Rod Drive Drain and Vent Valves Failed Timing; dated April 19, 2005
Issue Report 324599; Scram Discharge Volume Drain Valve - In-service Testing, 1-0302-22D; dated April 14, 2005
Issue Report 324595; Scram Discharge Volume Inboard Drain Valve, 1-0302-22C; dated April 14, 2005
QCOS 1600-32; Drywell/Torus Closeout; dated April 17, 2005
Issue Report 325572; Q1R18 Drywell Closeout Q1R18; dated April 17, 2005
Issue Report 339884; Final Drywell Closeout Deficiencies During Q1M18; dated May 31, 2005

2OS1 Access Control to Radiologically Significant Areas; and
2OS2 As Low As Is Reasonably Achievable (ALARA) Planning and Controls

RWP 10004490; Recirc Pump, Remove/Install Motor and Impeller; Revision 2
RWP 10004446; U1 Main Turbine: Sandblasting Activities; Revision 0
RWP 10004986; U1/U2 Reactor Steam Dryer Demolition: Diving Activities; Revision 1
RWP 10005674; U2 Steam Dryer: Move To U2 Dryer/Separator Pit; Revision 0
RWP 10004457; U1 Disassembly/Reassembly/Cavity Work/Wall Cleaning; Revision 0
NF-AA-390; Spent Fuel Pool Material Control and Material Log; Revision 1
Nuclear Oversight Quarterly Reports; January-December 2004
Self-Assessment Reports; Access Control, Source Term Reduction, ALARA Planning and Controls, and Evaluation of ALARA Practices; dated October 2004-March 2005
AR00310140; NRC ID'D Issues During U2 RCIC Surveillance; dated March 8, 2005
AR00321347; NRC Observed Poor Radworker Practices; dated April 5, 2005
AR00317535; RAM Event Near Miss; dated March 26, 2005
AR00320471; Q1R18 OLL Estimate Venture Worker Hours Incorrect; dated March 31, 2005
AR00321215; NOS ID'D Poor Contamination Control Practices; dated April 5, 2005
AR00315955; Q1R18 OLL Unit 1 Rx Water Steaming; dated March 22, 2005
AR00258713; Tigerlock Area Exhaust Fan Potential Unmonitored Release; dated September 24, 2004
IR310120; Prompt Investigation Report: Reactor Recirculation Motor Shipping Container Opened Without RP Support; dated March 8, 2005
RP-AA-400; ALARA Program; Revision 3
RP-AA-220; Bioassay Program; Revision 2
RP-AA-400-1001; Establishing Collective Radiation Exposure Estimates and Goals; Revision 0
RP-AA-460; TIP Area Access Controls; Revision 0
RP-AA-301; Radiological Air Sampling Program; Revision 0
RP-AA-4002; Radiation Protection Refuel Outage Readiness; Revision 1
RP-AA-401; Operational ALARA Planning and Controls; Revision 4
RP-AA-460; Controls for High and Very High Radiation Areas; Revision 7

4OA2 Identification and Resolution of Problems

Limerick NRC Inspection Report 50-352/2002003 and 50-353/2002003; dated April 2003.
Nuclear Event Report LI-03-016 (Green); Potential Main Steam Isolation Vale Preconditioning Prior to In-Service Test; dated April 4, 2003
Nuclear Oversight Objective Evidence Report NOSA-QDC-04-05; dated June 1-10, 2004
QCOS 1600-32; Drywell/Torus Closeout; dated April 17, 2005
Issue Report 325572; Q1R18 Drywell Closeout Q1R18; dated April 17, 2005
Issue Report 339884; Final Drywell Closeout Deficiencies During Q1M18; dated May 31, 2005
Brio Report for Issue Reports on Breakers from January 1 - June 27, 2005; dated June 28, 2005
Brio Report for Issue Reports on Dampers from January 1 - June 27, 2005; dated June 28, 2005
Brio Report for Issue Reports on Reactor Feed Pumps from January 1 - June 27, 2005; dated June 28, 2005
Brio Report for Issue Reports on Leaks from January 1 - June 27, 2005; dated June 28, 2005
Brio Report for Issue Reports on Pump Motors from January 1 - June 27, 2005; dated June 28, 2005
Brio Report for Issue Reports on the Control Rod Drive System from January 1 - June 27, 2005; dated June 28, 2005

4OA3 Event Followup

Corporate Root Cause Report 299641-03; Single Failure Vulnerability of Safety Related Division 1 and 2 Protective Relay Circuitry; dated March 8, 2005
Prompt Investigation Report for Issue Report 297548; Quad Cities Station - 4160 Volt Relay Vulnerability; dated February 3, 2005
Issue Report 325313; Invalid Engineering Safety Function Actuation During Reactor Vessel Hydro; dated April 15, 2005
Prompt Investigation Report for Issue Report 325313; dated April 16, 2005
Apparent Cause Report for Issue Report 325313; dated May 17, 2005

4OA5 Other Activities

Issue Report 334825; Summary of Events and Recommendations for New Dryer Issues; dated May 12, 2005
Issue Report 337395; Dryer Strain Gauge S7 Exceeds Level 2 Criteria at 912 Megawatts Electric; dated May 22, 2005
Issue Report 337415; Rock 2202-5 Vibration Level Increase Exceeds Ten Percent; dated May 22, 2005
Issue Report 337433; Unit 2 Reactor Water Levels Channel Indicators Differ by 4 Inches; dated May 22, 2005
Issue Report 339728; New Unit 1 Dryer Installation Problem; dated May 31, 2005
Issue Report 339966; Lost Connection to 12A Strain Gauge While Troubleshooting; dated June 1, 2005

Issue Report 340112; Strain Gauge Problems; dated June 1, 2005
Issue Report 340929; Strain Gauge S36 and S3 Determined to be Inoperable; dated June 3, 2005
Issue Report 340943; TIC-1252 Test Condition 8 Data Set Truncated Due to Strain Gauge Noise; dated June 4, 2005
Issue Report 340961; TIC-1252 Level 1 Criteria Exceeded for Strain Gauge on Main Steam Line C; dated June 4, 2005
Issue Report 341056; TIC-1252 Level 2 Criteria Exceed Acoustic Analysis; dated June 5, 2005
Issue Report 341273; High Station MVAR Loading Impeded Steam Dryer Testing; dated June 6, 2005
Issue Report 341151; Feedwater Line 1-3271B-1" Vibration Exceeds EPRI Criteria at 2887 Megawatts Thermal; dated June 5, 2005
Engineering Change 355836; Evaluate Potential Fatigue Issues for the Unit 1 Steam Dryer; Revision 0
TIC-1252; Quad Cities Unit 1 Power Ascension Test Procedure for the Reactor Vessel Steam Dryer Replacement; Revision 0
TIC-1262; Quad Cities Unit 1 Power Ascension Test Procedure for the Reactor Vessel Steam Dryer Replacement; Revision 0
TODI QDC-05-019; Quad Cities Units 1 and 2 Strain Gauge Information; Revision 1
EE-AA-600-1042; On-line Risk Management; Revision 3
OP-AA-108-107-1002; Interface Agreement Between Exelon Energy Delivery and Exelon Generation for Switchyard Operations; Revision 0
QCOA 6000-02; Main Generator Abnormal Operation; Revision 4
QCOA 6100-04; Station Blackout; Revision 9
WC-AA-101; On-line Work Control Process; Revision 10

LIST OF ACRONYMS USED

ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As Is Reasonably Achievable
CFR	Code of Federal Regulations
FIN	Finding
IMC	Inspection Manual Chapter
LER	Licensee Event Report
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
RWP	Radiation Work Permit
SDP	Significance Determination Process
URI	Unresolved Item
Vdc	Volt direct current