October 27, 2003

Mr. John L. Skolds, President
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 05000254/2003009;
05000265/2003009

Dear Mr. Skolds:

On September 30, 2003, 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 September 30, 2003, 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 four issues of very low safety significance (Green). Three of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of these Non-Cited Violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the 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, 801 Warrenville Road, Lisle, IL 60532-4351; 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.

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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 05000254/2003009; 05000265/2003009
w/Attachment: Supplemental Information

cc w/encl:
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Quad Cities Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Quad Cities
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	05000254/2003009; 05000265/2003009
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	July 1 through September 30, 2003
Inspectors:	K. Stoedter, Senior Resident Inspector R. Telson, Acting Senior Resident Inspector M. Kurth, Resident Inspector S. Caudill, Resident Inspector - Duane Arnold J. Jacobson, Senior Inspector R. Ganser, Illinois Emergency Management Agency
Observers:	A. Garmoe, Summer Intern A. Wichman, Summer Intern
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000254/2003009, 05000265/2003009; 07/01/03-09/30/03; Quad Cities Nuclear Power Station, Units 1 & 2; Surveillance Testing, Problem Identification and Resolution, and Event Followup.

This report covers a 3-month period of baseline resident inspection. The inspection was conducted by Region III inspectors and the resident inspectors. Three Non-Cited Violations (NCV) and four Green Findings 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. Inspector-Identified and Self-Revealed Findings

Cornerstone: Initiating Events

- Green. A self-revealing half scram occurred on July 10, 2003, due to the failure to fully evaluate a change to the test equipment configuration specified in surveillance procedure QCIS 0500-01, "Unit 1 Division 1 Low Condenser Vacuum Scram Calibration and Functional Test." The failure to properly evaluate the configuration change was considered a human performance issue and a Non-Cited Violation of Technical Specification 5.4.1.

  This finding was more than minor because it impacted the procedure quality, configuration control, and design control attributes of the initiating events cornerstone, and affected the cornerstone objective of limiting the likelihood of events that upset plant stability. The inspectors determined that the finding was of very low safety significance because the exposure time was short, all other mitigating systems were available, and the condenser could have been recovered if needed. The licensee's immediate corrective actions included removing the test equipment, restoring the low condenser vacuum circuitry, and properly determining an alternate means to perform the surveillance test. (Section 1R22)

- Green. The inspectors determined that the failure to perform visual inspection of the dryer's internal surfaces and complete an extent of condition review which evaluated the full spectrum of frequencies acting on the Unit 2 steam dryer following a June 2002 failure contributed to a repetitive failure in June 2003.

  This finding was more than minor because it impacted the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective of limiting the likelihood of events that upset plant stability. The inspectors determined that this finding was of very low risk significance because the failed steam dryer did not contribute to a loss of safety function for any mitigating system. The licensee's corrective actions included repairing the steam dryer and implementing additional measures to ensure that appropriate extent of condition reviews were completed when required. (Section 4OA2.3)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a Green finding and a Non-Cited Violation due to the failure to follow procedures after discovering that a shutdown cooling suction valve would not operate from the control room. The failure to follow procedures resulted in several human performance issues including: the failure to initiate a work request when required, the performance of troubleshooting activities prior to developing a formal troubleshooting plan, the use of repetitive cycling to resolve equipment deficiencies, and the use of the equipment cycling results as a basis for continued component operability. The deficiencies in work request initiation subsequently contributed to the licensee's failure to correct this equipment deficiency.

  The inspectors determined that the failure to follow procedures after discovering this equipment deficiency was more than minor because if left uncorrected, this practice could lead to the failure to appropriately identify and correct subsequent deficiencies. The inspectors determined that the finding was of very low safety significance because the shutdown cooling suction valve could be manually operated if needed and adequate decay heat removal could be maintained using the remaining residual heat removal equipment. The licensee's corrective actions included maintaining the ability to manually open the suction valve, performing preventive maintenance on the valve's breaker, and re-enforcing the actions to be taken upon discovering an equipment deficiency. (Section 4OA2.2)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Green finding and a Non-Cited Violation due to the discovery of a reactor coolant pressure boundary leak on the Unit 1 reactor pressure vessel head vent piping in May 2003.

  The inspectors determined that the presence of a reactor coolant system pressure boundary leak was more than minor because it impacted the equipment performance attribute and the objective of the initiating events cornerstone and the reactor coolant system and barrier performance attribute and objectives of the barrier integrity cornerstone. The inspectors determined that this finding was of very low safety significance because additional equipment not credited in the Probabilistic Risk Assessment was available to mitigate the leak and the contribution of this type of event to the baseline core damage frequency was small. Corrective actions included cutting out the weld defect which caused the leak and repairing the pipe. (Section 4OA3.2)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at full power, with the exception of minor power reductions for condenser flow reversal activities, until September 14, when operations personnel lowered reactor power to 850 megawatts electric (MWe) to conduct control rod maneuvers. Unit 1 returned to full power later the same day. On September 21, operations personnel lowered reactor power to 600 MWe to perform additional control rod maneuvers and conduct maintenance on the 1A reactor feedwater pump. Unit 1 ended the inspection period operating at full power.

Unit 2 began the inspection period at 845 MWe following completion of the steam dryer repairs. On July 29, operations personnel began increasing power to 912 MWe. At approximately 890 MWe, the control room received multiple sequence of event recorder alarms for the 3D power operated relief valve (PORV). In addition, chatter was observed on the 1D/2D main steam isolation valve closure relay and the C main steam line low pressure relay. Due to the relay chatter and the 3D PORV alarm frequency, the operators returned Unit 2 to 845 MWe on July 30. A second power ascension from 845 MWe to 912 MWe was conducted from August 13 through August 16. On August 17, operations personnel discovered a leak on the 2B condensate pump inboard bearing cooling water supply line which required a power reduction to 775 MWe to repair. Following this repair, Unit 2 operated at full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope

On July 20 and 27, 2003, the licensee entered QCOA 0010-10, “Tornado Watch/Warning or Severe Winds,” due to experiencing severe thunderstorms and high winds in the area. Following these occurrences, the inspectors reviewed QCOA 0010-10 to determine the actions to be taken prior to experiencing this type of weather condition. The inspectors toured outside areas, including the switchyard, and verified that the licensee appropriately controlled items which could become missiles during adverse weather conditions. The inspectors also interviewed operations personnel on shift during the adverse weather conditions to ensure that actions listed in QCOA 0010-10 were completed as required.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Partial Walkdowns

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 1 scram discharge volume;
- Unit 1 high pressure coolant injection and the safe shutdown makeup pump;
- Unit 1 residual heat removal loop A; and
- Unit 2 residual heat removal loop B.

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 required. The inspectors examined the material condition of each accessible component and observed equipment operating parameters to confirm that there were no obvious material condition deficiencies. The inspectors reviewed work orders and condition reports associated with the inspected equipment to verify that those documents did not reveal issues that could affect equipment functionality. The inspectors used the information in the appropriate sections of the Updated Final Safety Analysis Report to determine the functional requirements of the systems.

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

During the week of September 15, the inspectors performed a complete walkdown of the emergency diesel generators (one sample). The diesel generators were selected due to their high safety-significance and risk-significance. The inspection consisted of the following activities:

- a review of plant procedures (including selected abnormal and emergency procedures), drawings, the system health report, Technical Specifications, and the Updated Final Safety Analysis Report to determine overall system health, proper system alignment, and the system's licensing basis;
- a review of outstanding maintenance work requests to determine items in need of repair;
- a review of outstanding or completed temporary and permanent modifications to the system; and
- an electrical and mechanical walkdown of the system to verify proper alignment, component accessibility, availability, and condition.

The inspectors also reviewed selected issues documented in condition reports to verify that the issues were appropriately addressed.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed a routine walkdown of accessible portions of the following risk significant fire zones:

- Fire Zone 1.1.1.6, Unit ½ Reactor Building 690'-6" Elevation;
- Fire Zone 6.3, Unit ½ Auxiliary Instrument Room;
- Fire Zone 8.2.1.A, Unit 1 Condensate Pump Room;
- Fire Zone 8.2.3.A, Unit 1 Control Rod Drive Pump Area;
- Fire Zone 8.2.7.A, Unit 1 Turbine Building Hydrogen Seal Oil Area and Motor Control Centers; and
- Fire Zone 8.2.8.E, Unit 1 Main Turbine Floor.

The inspectors verified that transient combustibles were controlled in accordance with the licensee's procedures. During a walkdown of each fire zone, the inspectors observed the physical condition of fire suppression devices and passive fire protection equipment such as fire doors, barriers, and penetration seals. 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.

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

External Flooding Review

a. Inspection Scope

The inspectors conducted an annual review of the licensee's external flooding procedures. The review included discussing the procedure steps with operations, maintenance, engineering, and security personnel to confirm that the actions could be accomplished within the required time; verifying that flooding-related equipment was readily available, in the specified location, appropriately labeled, and in good material condition; ensuring that preventive maintenance tasks on external flooding related equipment were completed; and verifying that flooding problems entered into the corrective action program were adequately addressed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On July 18 and September 8, 2003, the inspectors observed operations crews in the simulator (two samples). The July 18 scenario consisted of a reactor recirculation pump speed signal failure, a reactor recirculation pump drive motor breaker trip, and a recirculation loop discharge pipe rupture. The scenario simulated on September 8, included a master feedwater regulator valve controller failure, a spurious turbine trip, an anticipated transient without scram, fuel damage, and a containment breach.

The inspectors evaluated crew performance in the areas of:

- clarity and formality of communications;
- ability to make timely actions in the safe direction;
- prioritization, interpretation, and verification of alarms;
- procedure use;
- control board manipulations;
- oversight and direction from supervisors; and
- group dynamics.

Crew performance in these areas was compared to licensee management expectations and guidelines as presented in the following documents:

- OP-AA-101-111, “Rules and Responsibilities of On-Shift Personnel,” Revision 0;
- OP-AA-103-102, “Watchstanding Practices,” Revision 1;
- OP-AA-103-104, “Reactivity Management Controls,” Revision 1; and
- OP-AA-104-101, “Communications,” Revision 0.

The inspectors verified that the crews completed the critical tasks listed in the above scenarios. If critical tasks were not met, the inspectors verified that crew and operator performance errors were detected and adequately addressed by the evaluators. The inspectors verified that the evaluators effectively identified crews requiring remediation and appropriately indicated when removal from shift activities was warranted. Lastly, the inspectors observed the licensee’s critique to verify that weaknesses identified during this observation were noted by the evaluators and discussed with the respective crews.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

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 system listed below. This system was selected based on it 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 system work practices, reliability, or common cause failures:

- Reactor Building Ventilation (Function Z5704).

The inspectors review included an examination of specific system 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.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk and Emergent Work (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 activities listed below 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.

- Work Week July 7 through 11, 2003, including Unit 1 high pressure coolant injection surveillance testing;
- Work Week July 20 through 25, 2003, including Unit 2 "A" containment air monitor system maintenance and Unit 1 high pressure coolant injection vacuum breaker functional testing;

- Unit 2 high pressure coolant injection surveillance testing conducted on August 13;

- Work Week August 18 through 22, including a 2A control rod drive pump oil change and 1A service air compressor maintenance; and

- Unit 2 reactor core isolation cooling system bearing oil change out and subsequent testing conducted on September 3.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors assessed the operability evaluations associated with the following condition reports or issues:

- Condition Report 154716, Failure of Valve 2-1001-43A to Open on Two Attempts, dated April 19, 2003;

- Condition Report 165978, Specific Valve Lineups have Potential to Render High Pressure Coolant Injection System Inoperable, dated July 2, 2003;

- Condition Report 167467, Unit 2 Diesel Generator Cooling Water Pump Vibration Analysis Adverse Trending, dated July 14, 2003;

- Condition Report 167721, 1A Drywell Radiation Detector Not Fully Inserted, dated July 14, 2003;

- Condition Report 168367, Extended Power Uprate Loadings on the Unit 1 Steam Dryer May Produce Flow Induced Pressure Oscillation Forces that Exceed Allowables, dated July 24, 2003;

- Condition Report 169869, Non-conforming Design for Main Steam Line Low Pressure due to Extended Power Uprate, dated July 31, 2003; and

- Potential Seismic Qualification Issue due to Lack of Doors on Auxiliary Equipment Electric Room Panels, various dates.

The inspectors reviewed the technical adequacy of each evaluation 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. The inspectors also reviewed issues entered into the corrective action program to verify that the issues were appropriately characterized and corrected.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors assessed the following operator workaround:

- 03-00 OWA, Containment H_2O_2 Monitor Torus Sample Line Heat Trace Temperature Issue, dated February 27, 2003.

The inspectors reviewed the details of the workaround to assess any potential effect on the functionality of mitigating systems. The inspectors reviewed the technical adequacy of the workaround documentation against the Updated Final Safety Analysis Report and other design information to assess if the workaround conflicted with any design basis information. When procedure changes were required, the inspectors verified that the procedure changes were technically correct and implemented in a timely manner. Lastly, the inspectors compared the information in abnormal and emergency operating procedures to the workaround information to ensure that the operators maintained the ability to implement these procedures when required.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed documentation associated with repairs to the Unit 2 steam dryer which failed in June 2003. The review included evaluating the results of GE Nuclear Energy (GENE) Field Deviation Disposition Requests, GENE design drawings for the dryer modifications, repair welding and inspection procedures, GE and Stearns-Roger assembly drawings of the dryer, and stress results from the licensee's computerized finite element analysis of the modified dryer structure. The inspectors also met with Exelon personnel to discuss the dryer repairs and the analytical basis supporting the repair.

b. Findings

Prior to completing this inspection, the NRC initiated a special inspection to review the circumstances which led to the repeat dryer failure and assess the adequacy of the licensee's dryer repairs. The results of this inspection were documented in NRC Inspection Report 05000265/2003011.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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.

- QCOP 1400-01, Core Spray System Preparation For Standby Operation, Revision 14, on May 21;
- QCIS 2400-01, Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test, Revision 13, on July 14;
- QCOS 6600-43, Unit ½ Diesel Generator Load Test, Revision 12, on July 18;
- QCOS 1300-05, Quarterly Reactor Core Isolation Cooling Pump Operability Test, on September 3; and
- QCOS 1000-04, Residual Heat Removal Service Water Pump Operability Test, Revision 36, and QCOS 1000-06, Residual Heat Removal Pump/Loop Operability Test, Revision 34, on September 5.

b. Findings

No findings of significance were identified.

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:

- QCIS 2400-01, Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test, Revision 13, on September 19, 2002, and March 13 and 19, 2003;
- QCIS 0500-01, Unit 1 Division 1 Low Condenser Vacuum Scram Calibration and Functional Test, Revision 10, on July 11, 2003;

- QCOS 2300-15, High Pressure Coolant Injection Drain Pot Level Switch, Drain Valve, Gland Seal Condenser High Level Alarm, and Steam Line Drain Functional Verification, Revision 18, on July 11, 2003;

- QCOS 6600-02, 03, 05, 06, 15, and 42, Unit 2 Emergency Diesel Generator Surveillance Procedures, Various Revisions, on August 6 and 7, 2003;

- QCOS 2300-05, Unit 2 Quarterly High Pressure Coolant Injection Pump Operability Test, Revision 47, on August 13, 2003; and

- QCOS 1300-05, Unit 2 Quarterly Reactor Core Isolation Cooling Pump Operability Test, Revision 35, on September 13, 2003.

The inspectors verified that the structures, systems, and components tested were capable of performing their intended safety function by comparing the surveillance procedure 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 test 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 surveillance test. Following test completion, the inspectors conducted walkdowns of the test areas to verify that the test equipment had been removed and that the system was returned to its normal standby configuration.

b. Findings

Low Condenser Vacuum Scram Calibration and Functional Test

Introduction: A self-revealing half scram occurred due to the failure to fully evaluate a change to the test equipment configuration specified in surveillance procedure QCIS 0500-01, "Unit 1 Division 1 Low Condenser Vacuum Scram Calibration and Functional Test." This issue was considered to be of very low safety significance (Green) and was dispositioned as a Non-Cited Violation.

Description: On July 10 instrument maintenance technicians attempted to conduct surveillance testing in accordance with QCIS 0500-01. This surveillance test implemented the use of a test box to prevent the initiation of reactor protection system half scrams during testing. Step H.6 of QCIS 0500-01 directed the technicians to install a test box on specific terminal posts within the reactor protection system cabinets. During the installation, the technicians encountered difficulty due to a recorder already being installed in the same location and clearance issues inside the cabinet.

The technicians immediately communicated their inability to install the test box to operations personnel. The instrument maintenance supervisor was not contacted. The technicians and operators reviewed QCIS 0500-01, the associated electrical prints, and the recorder installation and identified a point on the recorder which they believed was electrically equivalent to the procedurally specified terminal posts. Based upon this review, a decision was made to install the test box at the equivalent point and continue performing the surveillance. During as found testing of low condenser vacuum switch 1-0503-A, an unexpected half scram occurred on reactor protection system channel A. Following the half scram, the technicians stopped all work and placed the equipment in a safe condition.

The licensee determined that the half scram occurred because the operators and the technicians failed to fully evaluate the affects of connecting the test box to the back of the recorder prior to installation. Although the alternate point chosen by the technicians and the operators was electrically equivalent to the point specified in QCIS 0500-01, the fact that the recorder test leads contained 0.1 amp fuses which would blow when subjected to the 1.12 amp current experienced during the surveillance test was not recognized.

Analysis: The inspectors determined that the failure to fully evaluate the impact of installing the test box to the back of the recorder prior to installation was more than minor because it involved the procedure quality, configuration control, and design control attributes of the initiating events cornerstone and resulted in a half scram which upset plant stability. This issue affected the cross-cutting area of human performance in that the technicians and the operators did not recognize the need to implement the temporary procedure change process and evaluate the impact of installing the test box in an alternate location prior to installation.

The inspectors determined that this finding should be evaluated using the Significance Determination Process described in Inspection Manual Chapter 0609, "Significance Determination Process," because the finding was associated with an increase in the likelihood of an initiating event. The inspectors consulted the Significance Determination Process Phase 1 Worksheet and determined that a Phase 2 evaluation was required based upon the finding contributing to both the likelihood of a reactor trip and that the condenser (mitigating equipment) would not be available.

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 inspectors determined that the exposure time was less than 3 days since the plant was restored to a safe condition immediately following the half scram. For each Significance Determination Process worksheet completed, the inspectors assumed that all mitigating systems equipment was available except for the condenser. The inspectors allowed credit for recovering the condenser. Using these assumptions, the inspectors evaluated six core damage sequences. Worksheet results ranged from 9 to 14 points. The most dominant core damage sequence involved a transient and the loss of the power conversion system with the containment heat removal and late inventory makeup equipment available. The inspectors concluded that this finding was of very low safety significance (Green) because the exposure time was short, all other mitigating systems were available, and the condenser could have been recovered if needed.

Enforcement: Technical Specification 5.4.1 required that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Section 1.a of Regulatory Guide 1.33 required administrative procedures governing the procedure adherence process. Procedure HU-AA-104-101, "Procedure Use and Adherence," was the procedure established by the licensee to implement the requirements of Technical Specification 5.4.1 and Regulatory Guide 1.33, Section 1.a. Procedure HU-AA-104-101, Step 4.1.1, required procedures to be followed as written. Step 4.1.7 of HU-AA-104-101 required a procedure user to stop and notify their supervisor when a procedure could not be performed as written. Lastly, Step 4.2.1 required that a procedure change request be initiated when a procedure could not be performed as written. Contrary to the above, on July 10, 2003, the technicians failed to notify their supervisor after identifying that QCIS 0500-01 could not be performed as written. In addition, neither the technicians nor the operators initiated a procedure change request to revise QCIS 0500-01 prior to installing the required test equipment in an alternate location. This violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2003009-01)**. This violation is in the licensee's corrective action program as Condition Report 167044. Immediate corrective actions included removing the test equipment, restoring the condenser vacuum circuitry, and determining another method to safely perform the surveillance test. Other corrective actions included briefing instrument maintenance personnel on procedure adherence and notification requirements and continuing the implementation of the instrument maintenance department performance improvement initiative.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed documentation for the following temporary configuration changes:

- Engineering Change 340650, Setpoint Change for Containment H_2O_2 Monitor Torus Sample Heat Trace Controllers TIC 2-2400-2A and TIC 2-2400-2B, dated April 30, 2003;

- Engineering Changes 343683 and 344103, Change the Setpoint for the Main Steam Line Low Pressure Reactor Protection System Switch, dated August 5, 2003; and

- Engineering Change 344148; Lift Leads at 2-2202-32 Panel to Eliminate a False Open Indication on the PORV 2-0203-3D Annunciator Circuit; dated August 4, 2003.

The inspectors assessed the acceptability of each temporary configuration change by comparing the 10 CFR 50.59 screening and evaluation information against the Updated Final Safety Analysis Report and Technical Specifications. The comparisons were performed to ensure that the new configurations remained consistent with design basis information. The inspectors performed field verifications to ensure that the modifications were installed as directed; the modifications operated as expected; modification testing adequately demonstrated continued system operability, availability, and reliability, and that operation of the modifications did not impact the operability of any interfacing systems. The inspectors also reviewed condition reports initiated during or following the temporary modification installation to ensure that problems encountered during the installation were appropriately resolved.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On September 15, the inspectors observed an operations crew participate in an emergency preparedness simulator drill which contributed to the Emergency Preparedness Drill and Exercise Performance Indicator. The inspectors monitored the operations crew's response to a drywell radiation monitor failure, a reactor recirculation pump seal failure, and a small break loss of coolant accident which resulted in high drywell temperature, a loss of reactor water level indication, and flooding the reactor pressure vessel. The inspectors verified that appropriate actions were taken by the operators, the proper emergency procedures were implemented, and that the shift manager made the appropriate emergency classifications in a timely manner. The inspectors attended the licensee's critique to verify that training personnel and operations department management adequately evaluated the crew's ability to implement the emergency plan.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Mitigating Systems Performance Indicator Verification

a. Inspection Scope

The inspectors interviewed licensee personnel and reviewed Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," licensee memoranda, operator logs, condition reports, and previous NRC inspection reports to verify the accuracy of the performance indicators listed below for both units from January 2002 until April 2003:

- Safety System Functional Failures;
- Residual Heat Removal Unavailability; and
- Alternating Current Power Unavailability.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Record Keeping Weakness Results in Determining Root Cause Based Upon Reasonable Assurance Rather than Fact

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the problem identification and resolution program following the discovery of a large amount of air in the 1B core spray discharge piping. The inspectors reviewed the root cause investigation charter to determine the scope of the investigation and the root cause report to determine the circumstances which resulted in the 1B core spray system being inoperable. The inspectors interviewed the root cause investigation team, operations personnel, the root cause sponsoring manager, and members of the management review committee to assess the actions taken to determine the root cause and the proposed corrective actions.

b. Issues

On May 20, during a Unit 1 shutdown, operations personnel conducted testing in accordance with QCTS 0600-20, "Core Spray Isolation Valve Local Leak Rate Test." The 1B core spray discharge piping was drained to complete the test. Upon test completion, operations personnel filled and vented the 1B core spray system as directed by system operating procedure QCOP 1400-01, "Core Spray System Preparation for Standby Operation."

On May 29, operations personnel placed Unit 1 in a mode which required the 1B core spray system to be operable. Approximately 5 days later, the licensee discovered approximately 7 minutes of air in the discharge piping while conducting the 1B core spray vent verification test using surveillance procedure QCOS 1400-10, "Core Spray Operability Verification." (See Inspection Report 05000254/2003005; 05000265/2003005 for details.)

The licensee initiated a condition report and root cause investigation for this event. The root cause investigation team concluded that the large amount of air was introduced into the 1B core spray system due to the failure to complete a procedure step in QCOP 1400-01 on May 21. While the inspectors agreed with this root cause, they were concerned that the licensee stated that the root cause determination was based on "reasonable assurance" rather than fact.

The inspectors questioned the root cause investigation team to determine why the root cause determination was based upon reasonable assurance. The inspectors learned that the term "reasonable assurance" was used because the actual copy of QCOP 1400-01 used on May 21 was no longer available. In addition, the operators that restored the IB core spray system to service could not recall if the procedure step in

QCOP 1400-01 had been performed. The inspectors noted that the root cause report did not contain a discussion regarding the difficulties encountered by the root cause team due to unavailability of the QCOP 1400-01 completed on May 21. However, a condition report on this topic was initiated during the inspection.

The inspectors questioned members of the operations department to determine why the QCOP 1400-01 conducted on May 21 was not kept. The inspectors were informed that operating procedures were not required to be kept because this type of procedure was not typically considered a record which demonstrated the capability for safe operation. Conversely, surveillance procedures such as QCOS 1400-10 were kept for the life of the plant since they formed a basis for continued safe operation. The inspectors concluded that although operating procedures like QCOP 1400-01 were not required to be kept, operations personnel used QCOP 1400-01 in place of QCOS 1400-10 to demonstrate compliance with Technical Specification Surveillance Requirement 3.5.1.1 on May 21. As a result, the QCOP 1400-01 used on May 21 should have been kept since it formed the basis which demonstrated the capability for safe operation..

The inspectors consulted Inspection Manual Chapter 0612, Appendix E, "Examples of Minor Issues," Section 1.c, and determined that the record keeping issue was more than minor. This determination was based on the fact that a thorough review of the QCOP 1400-01 used on May 21 may have identified the procedure steps that were not performed. In addition, the results of a subsequent venting test showed that the 1B core spray system was inoperable. The failure to ensure the 1B core spray system was operable prior to changing Unit 1 operating modes on May 29 resulted in the licensee violating Technical Specification 3.0.4. This violation of Technical Specification requirements was documented in Section 4OA7 of Inspection Report 05000254/2003005; 05000265/2003005. The document retention issues were included in Condition Report 172680. Corrective actions for this issue included initiating an Operations Department Standing Order which explained the appropriate methods to be used when returning equipment to an operable status and revising the equipment operability procedure to clarify the document retention requirements.

.2 Procedure Implementation Weaknesses Result in Failure to Identify Root Cause and Implement Appropriate Corrective Actions

a. Inspection Scope

As part of the residual heat removal system unavailability performance indicator inspection, the inspectors performed a word search of all condition reports initiated during the last year looking for equipment failures associated with the residual heat removal system. The inspectors used their system knowledge to review the word search results and selected Condition Report 154716 for further inspection. Condition Report 154716 documented two unsuccessful attempts to open residual heat removal A shutdown cooling suction valve 2-1001-43A from the control room. The inspectors interviewed operations, maintenance, and engineering personnel and reviewed pertinent control room log entries to determine the sequence of events prior to the valve's failure to open, the actions taken to determine the cause of the valve failure, and the licensee's corrective actions. The inspectors reviewed the Updated Final Safety Analysis Report and the Technical Specifications to determine the operability requirements and the licensing and design basis of the valve.

b. Findings

Introduction

The inspectors identified a Green finding and a Non-Cited Violation due to the failure to follow procedures after discovering that a shutdown cooling suction valve would not operate from the control room. The failure to follow procedures resulted in several human performance issues including: the failure to initiate a work request, the performance of troubleshooting activities prior to developing a formal troubleshooting plan, the use of repetitive cycling to resolve equipment deficiencies, and the use of the equipment cycling results as a basis for continued component operability. The work request initiation deficiencies subsequently contributed to the licensee's failure to promptly identify and correct this equipment deficiency.

Description

On April 19, 2003, valve 2-1001-43A failed to open from the control room. Operations personnel attempted to open the valve a second time and were unsuccessful. After the two unsuccessful attempts, operations personnel checked the valve's breaker. No abnormal conditions were identified. Following the breaker check, the operators contacted the electrical maintenance department for assistance. The electricians recommended that the operators cycle the breaker. Following the breaker cycling, operations personnel successfully opened valve 2-1001-43A from the control room.

Operations personnel initiated Condition Report 154716 to document the valve's failure to open. The inspectors performed a review of this event and identified the following deficiencies:

- Procedure OP-AA-108-105, "Equipment Deficiency Identification and Documentation," Step 3.2.3, required operations personnel to initiate a work request following the identification of an equipment deficiency. Although operations personnel documented the failure of valve 2-1001-43A to open in the control room logs and in a condition report, a work request was not initiated.

- Procedure MA-AA-716-004, "Conduct of Troubleshooting," Step 2.5 defined troubleshooting as a task that involved detection, diagnosis and repair of faulty equipment. In addition, Step 4.2.2 of the same procedure required that all physical troubleshooting work be done via the work control process. The inspectors determined that neither operations nor electrical maintenance personnel identified the need to generate a work request and enter the work control process prior to conducting troubleshooting on valve 2-1001-43A. As a result, the troubleshooting performed on valve 2-1001-43A was performed outside the work control process and was not documented on any retained record.

- Procedure OP-AA-108-105, Step 4.1.1, stated that coaxing (which included cycling) was not normally an acceptable method for correcting equipment deficiencies. Step 4.1.2 stated that coaxing should not be used as a means of maintaining operability. The inspectors determined that operations and maintenance personnel used the results of the breaker cycling to inappropriately determine that the deficiency associated with valve 2-1001-43A had been corrected. This same logic was also used to inappropriately justify the continued operability of valve 2-1001-43A from the control room.

- The supervisory review section of Condition Report 154716 stated that the valve’s failure to open could have been attributed to a deficiency with the valve’s breaker or operator. However, a work request to troubleshoot and/or repair the breaker or operator was not generated. As a result, the actual condition of the valve’s breaker and operator were unknown.

- Two supervisors, multiple departmental corrective action program coordinators and the management review committee reviewed Condition Report 154716 prior to the condition report being closed. However, none of these individuals recognized that the root cause of the valve’s failure to stroke had not been identified. Since the cause was not identified, corrective actions were not implemented.

Analysis

The inspectors consulted the Technical Specification Bases for the residual heat removal shutdown cooling equipment and determined that valve 2-1001-43A could be considered operable as long as the ability to reposition the valve locally was available. The inspectors determined that although an electrical problem could exist with the breaker or valve operator, this problem should not impact the ability to operate valve 2-1001-43A locally using the declutch lever and valve handwheel.

The inspectors determined that the failure to follow procedures after discovering this equipment deficiency was more than minor because if left uncorrected, this practice could lead to the failure to appropriately identify and correct subsequent deficiencies. Since Quad Cities Unit 2 was in a shut down condition when this issue occurred, the inspectors assessed the significance of this issue using Inspection Manual Chapter 0609, Appendix G, “Shutdown Operations Significance Determination Process,” Table 1, for boiling water reactors in cold shutdown with a time to boil of greater than 2 hours and a reactor coolant system level less than 23 feet above the top of the flange. Page T-21 of Table 1 required two residual heat removal shutdown cooling subsystems to be operable with one system in operation. The inspectors determined that the Table 1 requirement was met as the remaining three residual heat removal pumps were available to perform the shutdown cooling function and the B pump was placed in service. The inspectors referred to Page T-22 of Table 1 and determined that the failure to identify and correct the deficiency which led to the inability to operate valve 2-1001-43A from the control room was of very low risk significance (Green) since 2-1001-43A could be operated locally and adequate decay heat removal capability was maintained.

Enforcement

Criterion V of 10 CFR Part 50, Appendix B required that activities affecting quality be prescribed by documented instructions, procedures, or drawings appropriate to the circumstance. Contrary to the above, on April 19, 2003, the licensee performed troubleshooting on a safety-related residual heat removal valve (an activity affecting quality) without documented instructions, procedures, or drawings appropriate to the circumstance. This lack of documented instructions, procedures, and drawings contributed to the failure to promptly identify and correct the conditions which resulted in the valve's failure to open. This violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC's Enforcement Policy **(NCV 05000265/2003009-02)**. This issue was entered into the licensee's corrective action program as Condition Report 169407. Corrective actions for this issue included discussing this event with various departments, emphasizing the process to be used when equipment deficiencies occur, and performing an inspection of the breaker associated with valve 2-1001-43A.

.3 Review of 2002 Steam Dryer Failure Corrective Actions

a. Inspection Scope

The inspectors reviewed the corrective actions from the 2002 Unit 2 steam dryer failure, interviewed licensee personnel, and attended meetings between the NRC and Quad Cities management to determine if corrective actions following the 2002 dryer failure should have prevented the 2003 failure.

b. Findings

Introduction: One Green finding was identified due to the failure to perform a visual examination of the internal steam dryer surfaces and complete an extent of condition review which evaluated the full range of frequencies acting upon the Unit 2 dryer following the June 2002 failure. This problem identification and resolution weakness contributed to a second steam dryer failure in June 2003.

Description: In February 2002, the licensee implemented a 17.8 percent extended power uprate on Quad Cities Unit 2. Approximately 3 months later, unexpected changes in reactor power, pressure, level, main steam line flow and moisture carryover began to occur. The licensee determined that the unexpected changes in the above parameters were caused by a failure of the steam dryer cover plate (see Inspection Report 05000265/2002007 for details). The cover plate failed because of high-cycle fatigue due to high frequency acoustic resonance. Corrective actions included modifying both Unit 2 steam dryer cover plates and completing an extent of condition review on the remaining dryer components.

In June 2003, the licensee experienced a second failure of the Unit 2 steam dryer (see Inspection Report 05000265/2003011 for details). The licensee conducted a root cause analysis and determined that the second dryer failure occurred due to high cycle fatigue resulting from low frequency pressure oscillations.

The inspectors discussed both dryer failures with licensee personnel. The licensee stated that the results of a post-mortem examination of the fractured dryer surfaces showed that the dryer cracks began on the inside of the dryer. In addition, the inspectors determined that the extent of condition review performed following the first dryer failure focused on other high frequencies acting on the dryer rather than evaluating the full spectrum of frequencies acting on the dryer.

Analysis: The inspectors determined that the failure to conduct an extent of condition review which considered a broad frequency range and conduct a visual inspection of the dryer's internal surfaces following the 2002 dryer failure was more than minor because it impacted the equipment performance attribute of the initiating events cornerstone and affected the cornerstone objective of limiting the likelihood of events that upset plant stability. The inspectors also determined that this finding should be evaluated using the Significance Determination Process described in Inspection Manual Chapter 0609, "Significance Determination Process," because the finding impacted the structural integrity of the dryer which was required to ensure the operability of multiple mitigating systems. The inspectors completed the Phase 1 Significance Determination Process Worksheet and concluded that this finding was of very low safety significance (Green) as the dryer failure did not result in a loss of safety function for any mitigating system **(FIN 05000265/2003009-03)**. In addition, the dryer failure did not impact any of the assumptions included in the licensee's Individual Plant Examination of External Events.

Enforcement: This issue was not subject to NRC enforcement action since the steam dryer is a non-safety-related component. The licensee initiated Condition Report 162964 to document the extent of condition review issues. Corrective actions included implementing additional reviews to ensure that the extent of condition issues are identified and evaluated.

4OA3 Event Follow-up (71153)

.1 Review of Power Ascension Following Unit 2 Dryer Failure

a. Inspection Scope

The inspectors assessed the licensee's readiness for conducting a Unit 2 power ascension from 845 MWe to 912 MWe by attending the Plant Onsite Review Committee meetings, reviewing the power ascension procedures to verify that plant parameters used to assess steam dryer structural integrity were incorporated, and conducting a review of previously identified problems to ensure that the problems were appropriately corrected prior to increasing reactor power. During power ascension activities, the inspectors monitored the plant parameters listed in the power ascension procedure and determined that the dryer performed as expected. The licensee suspended the power ascension and initiated Condition Reports 169535 and 169596 on July 30 when two safety-related relays began chattering and frequent alarms associated with the 3D PORV were received. Prior to resuming the power ascension on August 13, the inspectors discussed the resolution of the condition reports listed above with operations, engineering, and maintenance personnel to verify that additional relay chattering should not have an adverse impact on plant safety. Resolution of the 3D PORV alarms was documented in Section 1R23 of this report.

b. Findings

No findings of significance were identified.

.2 Review of Licensee Event Reports

a. Inspection Scope

The inspectors performed an onsite review of records to evaluate the root cause and corrective actions for the licensee event reports discussed in the “Findings” section below. The inspectors evaluated the timeliness, completeness, and adequacy of the root cause and corrective actions in accordance with the requirements of 10 CFR Part 50, Appendix B, as appropriate.

b. Findings

(Closed) Licensee Event Report 05000254/2003-002-00: Mode Change with Core Spray Loop Inoperable due to Failure to Properly Fill and Vent. The inspectors documented a licensee identified violation in Section 4OA7 of Inspection Report 05000254/2003005; 05000265/2003005 based upon an initial review of this event. On August 1, 2003, the licensee submitted the event report which documented the root cause and corrective action information. The inspectors reviewed the event report and determined that the documented information did not change the inspectors’ initial assessment of the event.

(Closed) Licensee Event Report 05000265/2003-002-00: Self-Actuation of Main Steam Relief Valve due to Excessive Leakage Through Pilot Valve Seat. The inspectors documented a finding in Section 1R2 of Inspection Report 05000265/2003006 based on the initial review of the event. On June 12, 2003, the licensee submitted the event report which documented the root cause and corrective action information. The inspectors reviewed the event report and determined that the documented information did not change the inspectors’ initial assessment of the event.

(Closed) Licensee Event Report 05000265/2003-004-00: Reactor Shutdown due to Degraded Reactor Steam Dryer as a Result of Increased Steam Velocities from Extended Power Uprate. This issue was discussed in Section 4OA2.3 of this report. One Green finding was identified due to the licensee’s failure to assess the full range of frequencies acting upon the dryer following the first failure.

(Closed) Licensee Event Report 05000254/2003-001-00: Unit 1 Reactor Shutdown Due to Reactor Head Vent Steam Leak Constituting Pressure Boundary Leakage. The inspectors evaluated the facts and circumstances surrounding the reactor head vent pressure boundary leakage.

Introduction: The inspectors identified a Green finding and a Non-Cited Violation due to the discovery of a reactor coolant system pressure boundary leak on the Unit 1 reactor pressure vessel heat vent piping.

Description: During a May 20, 2003, drywell entry, the licensee identified a steam leak on the Unit 1 reactor pressure vessel head vent line. The reactor pressure vessel head vent line was a carbon steel pipe approximately 2 inches in diameter. The leak was determined to be upstream of the isolation valves and located at a coupling socket weld joint in a vertical pipe section.

After shutting down Unit 1, the licensee cut out the coupling socket weld joint. The joint was sent to an offsite laboratory for analysis. The laboratory analysis (Project Number QDC-65394) identified the characteristics of the leakage path surfaces on the failed reactor head vent line. Specifically, the report stated, “Leaking steam had eroded a portion of the surrounding weld.” In addition, a caption included with Figure 5 of the report stated, “The leak path was oxidized/corroded and appeared to have been eroded from the escaping steam.” The cause of the leak was a poor quality weld as shown by the significant amount of porosity, lack of fusion and excessive overlap in the failure region. The defect continued until the leak occurred due to long term corrosion and possible fatigue. A causal factor for the poor weld quality was due to the piping being located in close proximity to the bioshield wall making it difficult for welding access. This was an original construction weld dating back to 1970. Also based on a review of the licensee’s failure analysis information, an NRC engineering specialist determined that the steam leak had existed for greater than 12 hours.

The inspectors reviewed drywell leakage data to determine when the leak began. The inspectors determined that the average drywell unidentified leakage trended upward from approximately 0.25 gallons per minute to 0.67 gallons per minute between February 17 and May 20. The inspectors reviewed the results of the licensee’s May 20 drywell entry and determined that the increase in drywell unidentified leakage was most likely due to the leaking reactor head vent piping weld. However, the inspectors noted that the licensee also discovered a puddle of water near the C drywell cooler which could have been caused by a leak or the accumulation of condensation. The licensee isolated the cooler and elected not to investigate this potential leak. Based on this information, the inspectors concluded that no other leaks, other than the reactor head vent piping weld, contributed to the increase in drywell unidentified leakage.

Analysis: The inspectors determined that the leak in the reactor pressure vessel head vent line was also a reactor coolant system pressure boundary leak. The inspectors determined there were two performance deficiencies associated with the leak: (1) poor initial weld quality and (2) operating with increased unidentified leakage and failing to identify the source of leakage. Ultimately, the leakage was determined to be reactor coolant pressure boundary leakage. The inspectors determined that the operation of Unit 1 with reactor coolant pressure boundary leakage was more than minor because it impacted the equipment performance attribute of the initiating events cornerstone and the reactor coolant system and barrier performance attribute of the barrier integrity cornerstone.

The inspectors determined that this finding should also be evaluated using the Significance Determination Process in accordance with Inspection Manual Chapter 0609, “Significance Determination Process,” because the finding was associated with an increase in the likelihood of an initiating event and was associated with maintaining the integrity of the reactor coolant system. The inspectors consulted the Significance Determination Process Phase 1 Worksheet and determined that a Phase 2 evaluation was required due to the finding impacting both the initiating events and the barrier integrity cornerstones.

Using the Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station Units 1 and 2, Revision 1, dated May 2, 2002, the inspectors determined that the exposure time was greater than 30 days since the leak existed from February 17 until May 20. The inspectors also determined that a Significance Determination Process Worksheet was not available to assess the significance of the reactor head vent leak. The inspectors discussed the worksheet issue with the senior reactor analyst and were instructed to use the small break loss of coolant accident worksheet in an effort to bound the size of the leak. Prior to completing the worksheet, the inspectors assumed that all mitigating capability was available. Using this assumption, the inspectors evaluated four core damage sequences. The small break loss of coolant accident with early containment control sequence (SLOCA -EC) was given a value of 6 points and was considered to be potentially risk significant. Due to these results, the senior reactor analyst was required to complete a Phase 3 evaluation of this issue.

During the Phase 3 evaluation, the senior reactor analyst identified that the SLOCA-EC sequence was overly conservative. Specifically, the early containment control portion of the sequence represented vapor suppression of the containment. Early containment control was considered to be successful if 12 out of 12 vacuum breakers functioned. In reviewing the licensee's probabilistic risk assessment, the senior reactor analyst noted that the licensee defined success of vapor suppression as either 12 out of 12 vacuum breakers functioning (a passive action), actuating the containment sprays or completing a reactor pressure vessel blowdown; however, the Significance Determination Process worksheets did not allow additional credit for the containment sprays or the blowdown. If additional credit was provided for the containment sprays (a multi-train system) in the early containment control function, the full point value for the sequence would be 8. This would result in the sequence being of very low risk significance. Additionally, the licensee's probabilistic risk assessment identified the small break loss of coolant accident's contribution to the overall core damage frequency to be less than 1 percent of the baseline core damage frequency of 2.2 E-06 per reactor-year. This results in an overall contribution from all sources of small piping breaks to be less than 2.2 E-08 per reactor-year. Lastly, the NRC has recently removed the SLOCA-EC sequence from the Significance Determination Process worksheets at recently benchmarked plants due to its small contribution to small break loss of coolant accidents. Based upon the information discussed above, the inspectors concluded that this finding was of very low safety significance (Green).

<u>Enforcement</u>: Technical Specification 3.4.4 stated that no reactor coolant pressure boundary leakage was allowed when the reactor was operated in Modes 1, 2, or 3. When pressure boundary leakage existed, Technical Specification 3.4.4, Condition C, required that the licensee be in Mode 3 within 12 hours and Mode 4 within 36 hours. Contrary to the above, a reactor coolant pressure boundary leak existed on the Unit 1 reactor while operating in Mode 1 from February 17 until May 19, 2003. This violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2003009-04)**. This violation is in the licensee's corrective action program as Condition Report 159607. Corrective actions for this issue

consisted of repairing the leak to eliminate the reactor coolant pressure boundary leakage and examining additional welds both upstream and downstream of the leak.

4OA4 <u>Cross-Cutting Aspects of Findings</u>

A finding described in Section 1R22 of this report had, as its primary cause, a human performance deficiency, in that, operations and maintenance personnel failed to implement the procedure change process when a surveillance procedure could not be performed as written.

A finding described in Section 4OA2.2 of this report had, as its primary cause, a human performance deficiency, in that, operations and maintenance personnel failed to follow procedural requirements when a safety-related valve failed to operate as expected from the control room. The procedure adherence deficiencies contributed to a subsequent failure to identify the cause of the equipment malfunction and the failure to implement appropriate corrective actions.

A finding described in Section 4OA2.3 of this report had, as its primary cause, a problem identification and resolution deficiency, in that, the full spectrum of frequencies acting on the Unit 2 steam dryer were not addressed as part of an extent of condition review following the 2002 steam dryer failure. This resulted in a second failure of the steam dryer in June 2003.

4OA5 <u>Other Activities</u>

<u>Review of Institute Of Nuclear Power Operations Report</u>

The inspectors completed a review of the final report for the Institute of Nuclear Power Operations, June 2003 Evaluation, dated September 10, 2003.

4OA6 <u>Meetings</u>

The inspectors presented the inspection results to Mr. T. Tulon and other members of licensee management at the conclusion of the inspection on September 30, 2003. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. Some analyses performed by GE were considered proprietary. Those portions of the analytical work by GE considered proprietary were reviewed by the NRC inspectors; however, they are not discussed in detail in this report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
T. Tulon, Site Vice President
B. Swenson, Plant Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
G. Boerschig, Work Control Manager
R. Gideon, Engineering Manager
T. Hanley, Maintenance Manager
D. Hieggelke, Nuclear Oversight Manager
K. Leech, Security Manager
K. Moser, Chemistry/Environ/Radwaste Manager
M. Perito, Operations Manager

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000254/2003009-01	NCV	Unexpected Half Scram Occurred due to Failure to Evaluate Change in Equipment Configuration via the Procedure Change Process Prior to Installation
05000265/2003009-02	NCV	Condition Adverse to Quality not Identified and Corrected due to Failure to Follow Troubleshooting and Equipment Deficiency Procedures
05000265/2003009-03	FIN	Failure to Perform Thorough Extent of Condition Review and Internal Dryer Inspection Following First Steam Dryer Failure
05000254/2003009-04	NCV	Operation of Unit 1 with Reactor Coolant Pressure Boundary Leakage which Exceeded Technical Specification Requirements

Closed

05000254/2003009-01	NCV	Unexpected Half Scram Occurred due to Failure to Evaluate Change in Equipment Configuration via the Procedure Change Process Prior to Installation

05000265/2003009-02	NCV	Condition Adverse to Quality not Identified and Corrected due to Failure to Follow Troubleshooting and Equipment Deficiency Procedures
05000265/2003009-03	FIN	Failure to Perform Thorough Extent of Condition Review and Internal Dryer Inspection Following First Steam Dryer Failure
05000254/2003009-04	NCV	Operation of Unit 1 with Reactor Coolant Pressure Boundary Leakage which Exceeded Technical Specification Requirements
05000254/2003-002-00	LER	Mode Change with Core Spray Loop Inoperable due to Failure to Properly Fill and Vent
05000265/2003-004-00	LER	Reactor Shutdown due to Degraded Reactor Steam Dryer as a Result of Increased Steam Velocities from Extended Power Uprate
05000254/2003-001-00	LER	Unit 1 Reactor Shutdown Due to Reactor Head Vent Steam Leak Constituting Pressure Boundary Leakage
05000265/2003-002-00	LER	Self-Actuation of Main Steam Relief Valve Due to Excessive Leakage Through Pilot Valve Seat

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

Updated Final Safety Analysis Report

QCOA 0010-10; Tornado Watch/Warning or Severe Winds; Revision 11

Control Room Logs dated July 20 and 27, 2003

1R04 Equipment Alignment

QOM 1-0300-04; Unit 1 Control Rod Drive Valve Checklist; Revision 4

QCOP 0300-32; CRD Scram Discharge Volume Isolation and Draining; Revision 7

QCOP 1000-02; RHR System Preparation for Standby Operation; Revision 22

QCOP 2300-01; HPCI Preparation for Standby Operation; Revision 39

QCOP 2900-01; Safe Shutdown Makeup Pump System Preparation for Standby Operation; Revision 19

Condition Report 170249; 4KV Switchgear 31 Direct Current Transfer Control Switch out of Position on Safe Shutdown Makeup Pump Local Panel; dated August 4, 2003

Piping and Instrumentation Diagram M-69; Diagram of Service Water Piping Diesel Generator Cooling Water; Revision N

Piping and Instrumentation Diagram M-22; Diagram of Service Water Piping Diesel Generator Cooling Water; Revision U

Technical Specifications

Updated Final Safety Analysis Report

Monthly System Health Report for the Emergency Diesel Generators

Maintenance Rule Evaluation History for the Emergency Diesel Generators; dated September 3, 2003

Open Emergency Diesel Generator Work Orders; dated September 3, 2003

QOM 1-6600-01; Unit 1 Diesel Generator Valve Checklist; Revision 16

QOM 1-6600-02; Unit 1 Diesel Generator System Fuse and Breaker Checklist; Revision 3

QOM 2-6600-01; Unit 2 Diesel Generator Valve Checklist; Revision 18

QOM 2-6600-02; Diesel Generator 2 Fuse Checklist; Revision 4

QOM ½-6600-01; Unit ½ Diesel Generator Valve Checklist; Revision 12

QCOP 6600-01; Diesel Generator 1(2) Preparation for Standby Operation; Revision 29

QCOP 6600-04; Diesel Generator ½ Preparation for Standby Operation; Revision 22

Figure 8.3-1; Emergency Power System; Revision 5

1R05 Fire Protection

OP-AA-201-001; Fire Marshall Tours; Revision 1

Various Sections; Quad Cities Pre-Fire Plans; dated 2002

Various Sections; Quad Cities Fire Hazards Analysis; Revision 13; dated August 2001

1R06 Flood Protection

Updated Final Safety Analysis Report

Technical Requirements Manual

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 8

QCOA 0010-14; Lock and Dam #14 Failure; Revision 7

QCOP 4100-02; Portable Diesel Pump Operation; Revision 6

Work Order 474079; Perform Maintenance on the External Portable Pump Used for Flood Mitigation; dated July 10, 2003

Condition Report 103243; 12-volt Battery for the Darley Portable Pump (external flooding response equipment) is Drained Out; dated April 10, 2002

1R11 Licensed Operator Requalification

LOCT-1171 EPU; Recirculation Pump Speed Signal Failure - Recirculation Pump Drive Motor Breaker Trip - Recirculation Loop Discharge Pipe Rupture

LOCT-0102 EPU; Master Feedwater Regulator Valve Controller- Spurious Turbine Trip-ATWS, Fuel Damage and Containment Break

QGA 100; Reactor Pressure Vessel Control; Revision 7

QGA 101; RPV Control (ATWS); Revision 10

QGA 200; Primary Containment Control; Revision 8

QGA 500-1; RPV Blowdown; Revision 11

EP-AA-1006; Radiological Emergency Plan Annex for Quad Cities Station; Revision 18

1R12 Maintenance Effectiveness

Listing of Maintenance Rule Performance Criteria for Function Z5704 - Reactor Building Ventilation System; dated July 16, 2003

Technical Specifications

QCOP 5750-02; Reactor Building Ventilation System; Revision 16

QCOS 5750-10; Reactor Building Ventilation Isolation Dampers Pneumatic Accumulator System Pressure Decay and Fail Safe Test; Revision 9

Operator/Initial Continuing Training Lesson Plan LNF-5750.doc; Plant Building Ventilation; Revision 2

Condition Report 152288; Reactor Building Ventilation Dampers Failed QCOS 5750-10; dated April 4, 2003

Condition Report 93865; Unit 1 Reactor Building Exhaust Fans Tripped and Caused Loss of Building Differential Pressure; dated September 18, 2001

Condition Report 100785; 2A and 2C Reactor Building Exhaust Fans Tripped Unexpectedly; dated February 24, 2002

Condition Report 110665; 2A and 2B Reactor Building Exhaust Fans Trip and Auto Start due to Weather; dated June 5, 2002

Condition Report 131349; Standby Gas Treatment System Started to Control Reactor Building Differential Pressure; dated November 12, 2002

Condition Report 156774; 2A Reactor Building Supply Fan Damper Did Not Fully Close When System Placed in Standby; dated May 1, 2003

Condition Report 154869; Area Alarm High Temperature Steam Leak Detection Alarm Received; dated April 21, 2003

Maintenance Rule Evaluation History Report for Function Z5704; dated January - June 2003

List of Open Maintenance Work Requests on the Reactor Building Ventilation System; dated August 6, 2003

Reactor Building Ventilation Unavailability Trend; dated August 6, 2003

Piping and Instrument Diagram M-373; Diagram of Unit 2 Reactor Building Ventilation and Drywell Air Conditioning; Sheet 1; Revision AM

1R13 Maintenance Risk Assessment and Emergent Work

Work Week Safety Profile; Weeks of July 6, 20, and August 10, 17, and 31, 2003

Online Work Schedules; Weeks of July 6, 20, and August 10, 17, and 31, 2003

OU-QC-104; Daily Risk Factor Chart, Attachment 1; Revision 1

WC-AA-104; Review and Screening for Production Risk; Revision 4

Condition Report 165978; Specific Valve Lineups Have Potential to Render HPCI Inoperable; dated July 2, 2003

QCOS 2300-05; Quarterly HPCI Pump Operability Test; Revision 47

1R15 Operability Evaluations

Condition Report 169869; Non-conforming Design for Main Steam Line Low Pressure; dated July 30, 2003

Condition Report 169596; Main Steam Line Low Pressure Relay Chatter; dated July 30, 2003

Condition Report 169407; Troubleshooting Should Have Been Better Documented; dated July 29, 2003

Condition Report 154716; Failure of Valve 2-1001-43A to Open on Two Attempts; dated April 19, 2003

Condition Report 167467; Unit 2 Diesel Generator Cooling Water Pump Vibration Analysis Adverse Trending; dated July 14, 2003

Condition Report 165978; Specific Valve Lineups have Potential to Render High Pressure Coolant Injection System Inoperable; dated July 2, 2003

Condition Report 167721; 1A Drywell Radiation Detector Not Fully Inserted; dated July 14, 2003

QCIS 2400-01; Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test; Revision 13

LS-AA-105; Operability Determinations; Revision 1

Updated Final Safety Analysis Report

Technical Specifications

NRC Administrative Letter 98-10; Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety; dated December 1998

QCNPS Calculation NED-I-EIC-033; Main Steam Line Low Pressure Setpoint Error Analysis at Normal Operating Conditions; Revision 4A

QCNPS Calculation QDC-0261-I-0813; Instrument Drift Analysis for Barksdale Model B2T; Revision 00

QCOS 6600-06; Diesel Generator Cooling Water Pump Flow Rate Test; Revision 25

QCAP 0400-17; Station Lubrication Program; Revision 24

MA-AA-716-230-1005; CSI RBMWARE Database Setup Guideline; Revision 0

MA-AA-716-230-1002; Vibration Analysis Acceptance Guideline; Revision 0

Engineering Change Request 55973; Determine Why Electrical Panels in the Auxiliary Electric Room and the Relay House do not have Panel Covers; dated July 6, 1999

Condition Report Q1999-02019; Unguarded Electrical Panels; dated June 14, 1999

Condition Report Q2001-01964; Several Panels in the Auxiliary Electric Room do not have Back Panels; dated June 22, 2001

Condition Report 145704; Missing Electrical Panel Covers; dated February 21, 2003

Condition Report 168367; Extended Power Uprate Loadings on the Unit 1 Steam Dryer may Produce Flow Induced Pressure Oscillation Forces that Exceed Allowables; dated July 24, 2003

1R16 Operator Workarounds

OWA 03-00; Containment H_2O_2 Monitor Torus Sample Line Heat Trace Temperature Issue (Units 1 and 2); dated February 27, 2003

EC 340650; Setpoint Change for CAM H_2O_2 Monitor Torus Sample Line Heat Trace Controllers TIC 2-2400-2A and TIC 2-2400-2B; dated April 30, 2003

Condition Report 138067; Containment H_2O_2 Monitor Torus Sample Line Temperature; dated January 3, 2003

QCOP 2400-01; CAM Subsystem Operation; Revision 14

EC 344736; CAM System Sample Line Heat Trace; dated September 17, 2003

Condition Report 175405; Heat Tracing Not Functioning Properly; dated September 11, 2003

QGA 200-5; Hydrogen Control; Revision 5

1R17 Permanent Plant Modifications

GE Drawing series 728E947; Steam Dryer; dated December 2, 1966

Stearns-Roger Assembly Drawing L-21571; Steam Dryer, General Electric, Dresden; and L-21573 through L-21581; Steam Dryer, Dresden - Quad Cities; dated 1968-1969

GE Drawing 104R921, Sheets 2 and 3; Reactor Assembly; Quad Cities 1&2; dated May 29, 1968

GE Field Deviation Disposition Request No. EE2-0525; Description of Quad Cities Steam Dryer Installation of (Vortex) Mitigation Braces; dated June 19, 2003

GE Field Deviation Disposition Request No. EE2-0532; Description of Removal of Cracked Sections of Dryer Hood and Replacement of Removed Sections; dated June 18, 2003

Commonwealth Edison Drawing No. M-101; Main Steam Piping Plans and Sections; Rev. M

GE Drawing 105E3655; Steam Dryer (Modifications); Rev. 1 (Proprietary)

GE Report GENE-0000-0018-0985-0; Stress Analyses for The Quad Cities Unit 2, Stream Dryer Repair (Proprietary); Revision 1

ANSYS Computer Code Version 6.1

GE Procedure GENE-0000-012-0018-1651; Root Cause Evaluation Process (Proprietary); dated June 2003

GE Report GENE-0000-012-0017-6545; Reverse Stress Analyses for The Quad Cities Unit 2 Stream Dryer Repair; (to be published)

GE Design Specification 26A5450; Hold Down Replacement, Steam Dryer (Proprietary); Revision 1

GE Report GENE-0000-0017-7600-01; Quad Cities Unit 2 Dryer Repair CFD Class 3 (Proprietary); dated June 2003

GE Document DRF-0000-0009-4020; Dryer Test Design Review (Proprietary)

GE Document GENE-189-11-0292; Steam Dryer Vibration Measurement Program Class III (Proprietary); dated March 1992

GE Report MDE 199-0985 DRF-B11-00314; Susquehanna-1 Steam Dryer Vibration, Steady State and Transient Response (Proprietary); dated October 1985

GE Report NEDE-0000-0018-1636; Steam Dryer Outer Hood Time History Analyses; (to be published)

<u>1R19</u> <u>Post Maintenance Testing</u>

QCOP 1400-01; Core Spray System Preparation For Standby Operation; Revision 1

QCTS 0600-20; Core Spray Isolation Valve Local Leak Rate Test; Revision 12

QCOS 1400-10; Core Spray Operability Verification; Revision 13

QCAP 0230-19; Equipment Operability; Revision 12

Technical Specifications

QCIS 2400-01; Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test; Revision 13

Condition Report 167721; 1A Drywell Radiation Detector Not Fully Inserted; dated July 14, 2003

Condition Report 164026; Excess Gas Discovered in 1B Core Spray System; dated June 4, 2003

QCOS 0010-07; Equipment External Leak Test; Revision 1

QCAP 0400-17; Station Lubrication Program; Revision 24

Fragnet Associated with Residual Heat Removal and Residual Heat Removal Service Water Maintenance; dated August 28, 2003

QCEPM 0200-11; Inspection and Maintenance of Horizontal 4kV Cubicles; Revision 16

QCOS 1000-06; Residual Heat Removal Pump/Loop Operability Test; Revision 34

QCOS 1000-04; Residual Heat Removal Service Water Pump Operability Test; Revision 36

Condition Report 167736; Unit ½ EDG Bus 13-1 Breaker Failed to Close; dated July 15, 2003

Work Order 590775-01; Contingency Troubleshooting Package to Perform Electrical Troubleshooting on the Unit ½ EDG; dated July 15, 2003

QCOS 6600-43; Unit ½ Diesel Generator Load Test; Revision 12

QCOS 6600-43; Unit ½ Diesel Generator Load Test; Revision 13

QCOS 1300-05; Quarterly RCIC Pump Operability Test; Revision 35

QCOS 1600-31; Suppression Pool Water Temperature Monitoring; Revision 4

Work Order 552617; Sample and Change Oil for Unit 2 RCIC Pump Outboard Bearing

Work Order 552618; Sample and Change Oil for Unit 2 RCIC Pump Inboard Bearing

MA-AA-716-230-1001; Used Oil Data Interpretation Guidelines; Revision 0

1R22 Surveillance Testing

QCOS 2300-15; HPCI Drain Pot Level Switch, Drain Valve, Gland Seal Condenser High Level Alarm, and Steam Line Drain Functional Verification; Revision 18

MA-QC-741-206; Unit 2 ECCS LPCI Recirculation Riser High D/P Functional Test; Revision 0

QCIS 0500-01; Unit 1 Division 1 Low Condenser Vacuum Scram Calibration and Functional Test; Revision 10

Condition Report 164221; 3-Valve Manifold Mispositioning; dated June 20, 2003

HU-AA-101; Human Performance Tools and Verification Practices; Revision 1

HU-AA-104-101; Procedure Use and Adherence; Revision 0

OP-AA-108-101-1001; Component Position Determination; Revision 0

QCOS 1300-05; Unit 2 Quarterly RCIC Pump Operability Test; Revision 35

Condition Report 167721; 1A Drywell Radiation Detector Not Fully Inserted; dated July 14, 2003

QCIS 2400-01; Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test; Revision 13

Technical Specifications

Updated Final Safety Analysis Report

Condition Report 167044; Unexpected Reactor Protection System Channel A Trip Signal Received During Performance of Surveillance Test due to Blown Fuse in Recorder Test Lead; dated July 10, 2003

Apparent Cause for Condition Report 167044; dated August 15, 2003

QCOS 2300-05; Quarterly HPCI Pump Operability Test; Revision 47

Condition Report 165978; Specific Valve Lineups have Potential to Render HPCI Inoperable; dated July 2, 2003

QCIS 2400-01; Unit 1 Division 1 Drywell Radiation Monitor Calibration and Functional Test; Revision 13

QCOS 6600-05; Diesel Generator Fuel Oil Transfer Pump Flow Rate Test; Revision 20

QCOS 6600-03; Diesel Fuel Oil Transfer Pump Monthly Operability; Revision 16

QCOS 6600-06; Diesel Generator Cooling Water Pump Flow Rate Test; Revision 25

QCOS 6600-15; Functional Test for Diesel Generator Vent Nitrogen Backup System; Revision 15

QCOS 6600-42; Unit 2 Diesel Generator Load Test; Revision 13

QCOS 6600-02; Diesel Generator Air Compressor Operability; Revision 16

CY-QC-130-700; Diesel Fuel Oil Testing; Revision 6

1R23 Temporary Plant Modifications

Engineering Changes 343683 and 344103; Change the Setpoint for the Main Steam Line Low Pressure Reactor Protection System Switch; dated August 5, 2003

CC-MW-112-1001; Temporary Configuration Change Packages; Revision 3

CC-AA-112; Temporary Configuration Change Process; Revision 7

Calculation QDC-0261-I-0813; Instrument Drift Analysis for Barksdale Model No. B2T-A12SS/B2T-M12SS-TC [PS-1(2)-0261-30A, B, C, D]; Revision 0

Calculation NED-I-EIC-0033; Main Steam Line Low Pressure Setpoint Error Analysis; Revision 004A

Diagram 4E-2789E; Wiring Diagram Auto Blowdown Relay Panel 2202-32; Revision T

Diagram 4E-2575AK; Control Room Annunciator Panel 902-3 PT-9 of 11; Revision F

Diagram 4E-2461 Sheet 2; Schematic Diagram Auto Blowdown; Revision AJ

Diagram 4E-2816B; Wiring Diagram - Low Voltage Power Penetration X-104A; Revision AT

QCAN 902-3; Relief Valve 2-203-3C/3D and/or 3E is Open; Revision 3

Engineered Change 344148; Lift Leads at 2-2202-32 Panel to Eliminate a False Open Indication on the PORV - 3D Annunciator Circuit; dated August 4, 2003

OWA 03-00; Containment H_2O_2 Monitor Torus Sample Line Heat Trace Temperature Issue (Units 1 and 2); dated February 27, 2003

EC 340650; Setpoint Change for CAM H_2O_2 Monitor Torus Sample Line Heat Trace Controllers TIC 2-2400-2A and TIC 2-2400-2B; dated April 30, 2003

Condition Report 138067; Containment H_2O_2 Monitor Torus Sample Line Temperature; dated January 3, 2003

QCOP 2400-01; CAM Subsystem Operation; Revision 14

EC 344736; CAM System Sample Line Heat Trace; dated September 17, 2003

Condition Report 175405; Heat Tracing Not Functioning Properly; dated September 11, 2003

QGA 200-5; Hydrogen Control; Revision 5

1EP6 Emergency Preparedness Drill Evaluation

EP-AA-1006; Radiological Emergency Plan Annex for Quad Cities Station; Revision 18

Technical Specifications

QCGP 2-3; Reactor Scram; Revision 45

QGA 100; Reactor Pressure Vessel Control; Revision 7

QGA 200; Primary Containment Control; Revision 8

QGA 500-1; Reactor Pressure Vessel Blowdown; Revision 11

QGA 500-4; Reactor Pressure Vessel Flooding; Revision 12

QCAN 901(2)-4 C-7; Reactor Recirculation Pump B High Vibrations; Revision 3

QCOA 0202-06; Reactor Recirculation Pump Seal Failure; Revision 16

QCOA 0202-04; Reactor Recirculation Pump Trip - Single Pump; Revision 19

QCOS 1600-06; Emergency Core Cooling System and Primary Containment Isolation Trip Instrumentation Outage Report; Revision 14

QCOS 1600-05; Post Accident Monitoring Instrumentation Outage Report; Revision 12

QCAN 901(2)-3 A-16; Primary Containment High Pressure; Revision 10

QCOA 0201-01; Increasing Drywell Pressure; Revision 16

QOA 900-55 A-1; Row A Annunciator Procedures; Revision 6

QCOS 0202-09; Reactor Recirculation Single Loop Outage Report; Revision 12

4OA1 Performance Indicator Verification

Condition Report 168364; Performance Indicator for Scrams with Loss of Normal Heat Removal is in the Action Range; dated July 21, 2003

Condition Report 159693; Failure of 1-1001-43A to Fully Stroke; dated May 30, 2003

Condition Report 154716; 2-1001-43A Valve Failed to Open on Two Attempts; dated April 19, 2003

Condition Report 158654; Valve 1-1001-26A Failed to Open During Logic Test; dated May 14, 2003

Condition Report 139835; Extent of Condition Review for GE HMA Type Relay Failure; dated January 16, 2003

10 CFR Part 21 Notification; Deviation in Barton Instrument Differential Pressure Indicating Switches; dated May 10, 2002

Condition Report 112996; Barton Model 288A and 289A Differential Pressure Indicating Switches may Drift During Seismic Event; dated June 24, 2002

Condition Report 111121; Pinhole Leak on the Discharge of the 1B Residual Heat Removal Service Water Low Pressure Pump; dated June 8, 2002

Condition Report 110756; As Found Condition of the Intake Bay; dated June 5, 2002

Condition Report 171034; NRC Identified: Past Operability and Reportability Not Addressed Following Discovery of a Leak on the Discharge of the 1B Residual Heat Removal Service Water Low Pressure Pump; dated August 9, 2003

LS-AA-2070; Monthly Performance Indicator Data Elements for Safety System Unavailability - Residual Heat Removal Systems; Revision 3

LS-AA-2080; Monthly Performance Indicator Data Elements for Safety System Functional Failures; Revision 3

LS-AA-2040; Monthly Performance Indicator Data Elements for Emergency Alternating Current Power; Revision 3

4OA2 Identification and Resolution of Problems

Condition Report 164026-02; Root Cause Investigation of Inadequate Venting 1B Core Spray Loop due to Inadequate Procedure Adherence and Coordination of Work Activities; dated June 19, 2003

Condition Report 172680; Document Retention When Declaring Systems Operable; dated August 18, 2003

Condition Report 172621; Some Technical Specification Surveillance Requirements Not Documented; dated August 22, 2003

QCAP 0230-19; Equipment Operability; Revision 13

QCPWG Volume 1; Quad Cities Nuclear Power Station Procedure Writers Guide (General Writers Guide); Revision 6

HU-AA-101; Human Performance Tools and Verification Practices; Revision 1

HU-AA-108-101; Control of Equipment And System Status; Revision 1

HU-AA-104-101; Procedure Use and Adherence; Revision 0

QCOP 1400-01; Core Spray System Preparation For Standby Operation; Revision 1

QCTS 0600-20; Core Spray Isolation Valve Local Leak Rate Test; Revision 12

Technical Specifications

QCOS 1400-10; Core Spray Operability Verification; Revision 13

Tagging Order 1-1402-25B for Performance of QCTS 0600-20

Condition Report 169407; Troubleshooting Should Have Been Better Documented; dated July 29, 2003

LS-AA-125; Corrective Action Program Procedure; Revision 5

OP-AA-108-105; Equipment Deficiency Identification and Documentation; Revision 1

MA-AA-716-004; Conduct of Troubleshooting; Revision 1

Condition Report Q2001-01615; Non-Cited Violation NRC IR 00-20 Failure to Implement Required Actions of Technical Specifications; dated January 19, 2001

Licensee Event Report 05000265/2002-03; Reactor Shutdown due to Failure of Reactor Steam Dryer from Flow-Induced Vibrations as a Result of Extended Power Uprate

Condition Report 157494; Elevated Moisture Carryover Indicated on Unit 2; dated June 9, 2003

Condition Report 158145; Unit 2 Moisture Carryover Increase; dated May 9, 2003

Condition Report 160858; Unit 2 Moisture Carryover is Elevated; dated May 28, 2003

Condition Report 162964; Unit 2 Dryer Failure; dated June 12, 2003

Root Cause for Condition Report 162964; dated July 23, 2003

Condition Report 115510; Steam Dryer Found Damaged During Visual Inspection; dated July 12, 2002

Root Cause for Condition Report 115510; dated September 9, 2002

4OA3 Event Followup

Condition Report 169995; Narrow Range Reactor Pressure is Out of Tolerance; dated August 1, 2003

Condition Report 169535; Main Steam Isolation Valve 203-1D2D Closure Scram Signal Relay 590-102H Chattering; dated July 30, 2003

Condition Report 169596; Main Steam Line Low Pressure Relay Chatter; dated July 30, 2003

Condition Report 169603; D Main Steam Line Vibrations Potential Issues; dated July 30, 2003

Condition Report 170060; Unexpected Automatic Depressurization System Systems 1 and 2 Main Direct Current Power Failure Alarm/Reset; dated August 1, 2003

Condition Report 170097; Unexpected Automatic Depressurization System Systems 1 and 2 Main Direct Current Power Failure Alarm/Reset; dated August 2, 2003

Condition Report 169984; Narrow Range Pressure Out of Calibration; dated August 1, 2003

Main Steam Line Vibration Data; dated May 16, July 30, and August 14, 2003

TIC-678; New Procedure to Monitor Unit 2 Parameters During and After Power Ascension to Extended Power Uprate Power to Ensure Dryer Repairs were Effective; dated July 17, 2003

TIC-682; New Procedure to Monitor Reactor and Plant Parameters to Monitor Steam Dryer Performance and Investigate Main Steam Line C Low Pressure Switch Actuations During and Following Power Ascension to Extended Power Uprate Power Levels; dated August 12, 2003

System Engineering Department Memorandum; Summary of Action Steps Being Taken to Support Quad Unit 2 Load Increase to 912 MWe; dated July 24, 2003

Condition Report 159607; Pressure Boundary Leakage from 2 Inch Reactor Head Vent Line; dated May 20, 2003

QCOS 0010-08; High Radiation Area Inspection Guidelines; Revision 2

Condition Report 154275; 2-0203-3B PORV Inadvertently Opened at Power; dated April 16, 2003

QCOS 0203-02; Safety and Relief Valve Temperature Surveillance; Revision 13

4OA5 Other

Institute of Nuclear Power Operations Report; Quad Cities June 2003 Evaluation; dated September 10, 2003

LIST OF ACRONYMS USED

EC	Early Containment Control
GENE	General Electric Nuclear Energy
IM	Instrument Maintenance
IMC	Inspection Manual Chapter
MWe	Megawatts Electric
NCV	Non-Cited Violation
PORV	Power Operated Relief Valve
SLOCA	Small Break Loss of Coolant Accident
SLOCA-EC	Small Break Loss of Coolant Accident - Early Containment Control