July 30, 2002

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
NRC INTEGRATED INSPECTION REPORT 50-254/02-05; 50-265/02-05

Dear Mr. Skolds:

On June 30, 2002, the NRC completed an inspection at your Quad Cities Units 1 and 2 reactor facilities. The enclosed report documents the inspection findings which were discussed on June 26, 2002, with Mr. Tulon and other members of your staff.

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

Based on the results of this inspection, 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 deny these Non-Cited Violations, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Quad Cities Nuclear Power Station.

The NRC has increased security requirements at the Quad Cities Nuclear Power Station in response to terrorist acts on September 11, 2001. Although the NRC is not aware of any specific threat against nuclear facilities, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen licensees' capabilities and readiness to respond to a potential attack. The NRC continues to monitor overall security controls and will issue temporary instructions in the near future to verify by inspection the licensee's compliance with the Order and current security regulations.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 50-254/02-05, 50-265/02-05

cc w/encl: Site Vice President - Quad Cities Nuclear Power Station
Quad Cities Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Quad Cities
Chief Operating Officer
Senior Vice President - Nuclear Services
Senior Vice President - Mid-West Regional
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Vice President - Mid-West Operations Support
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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:	50-254/02-05, 50-265/02-05
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	April 1 through June 30, 2002
Inspectors:	K. Stoedter, Senior Resident Inspector G. Wilson, Acting Senior Resident Inspector J. Adams, Resident Inspector M. Kurth, Resident Inspector D. Funk, Physical Security Inspector J. House, Senior Radiation Protection Inspector R. Lerch, Project Engineer P. Pelke, Reactor Engineer T. Ploski, Senior Emergency Preparedness Inspector
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000254-02-05, IR 05000265-02-05, Exelon Nuclear, on 04/01 - 06/30/2002, Quad Cities Nuclear Power Station, Units 1 & 2, non-routine evolutions, operability evaluations, event follow-up, and other.

The inspection was conducted by resident and regional inspectors. This inspection identified four Green issues. Three of these issues involved Non-Cited Violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/ASSESS/index.html.

A. Inspector Identified Findings

Cornerstone: Initiating Events

Green. A lack of communications between operations personnel and an administrative senior reactor operator's failure to participate in a formal shift turnover resulted in operations personnel commencing a Unit 2 reactor startup with the manual reactor head vent isolation valves in the open position. The failure to participate in a turnover was considered a Non-Cited Violation of Technical Specification 5.4.1.

The inspectors determined that this issue was of very low safety significance because the leak created by the open manual reactor head vent isolation valves was small, and adequate mitigating equipment was available to respond to a potential transient condition (Section 1R14).

Green. A digital feedwater control system design weakness, in conjunction with the inadvertent grounding of a pressure transmitter during an instrument maintenance surveillance, resulted in a manual reactor scram due to increasing reactor vessel water level.

The inspectors determined that this issue was of very low safety significance because the feedwater system would have been recoverable following a Level 8 isolation signal, and adequate mitigating systems equipment remained available to place and maintain the plant in a stable condition (Section 4OA3).

Cornerstone: Mitigating Systems

Green. The inspectors identified a design deficiency and a Non-Cited Violation in that licensee personnel failed to perform a parts evaluation when installing hose clamps on the control rod drive system hydraulic accumulators instead of the seismically-qualified steel band clamps.

This issue was of very low safety significance because the design deficiency did not result in a loss of function as described in Generic Letter 91-18, “Resolution of Degraded and Non-Conforming Conditions and on Operability” (Section 1R15).

Green. The inspectors documented a Non-Cited Violation of 10 CFR 50.62, “Anticipated Transient Without Scram Rule,” due to the potential to lift the standby liquid control system relief valves during an anticipated transient without scram.

The inspectors determined that this finding was of very low safety significance because the standby liquid control system could be recovered during an anticipated transient without scram event, the cycling of the relief valves would allow a portion of the sodium pentaborate solution to be injected into the reactor vessel, and the plant remained within the acceptance criteria of the original anticipated transient without scram analyses during the relief valve lifts (Section 4OA5).

B. Licensee Identified Findings

Violations of very low safety significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

Report Details

Summary of Plant Status:

Unit 1 began the inspection period at 100 percent power. On May 11 the operators reduced reactor power to 205 megawatts electric (MWe) to repair the actuator and gear box for condenser flow reversing valve 1-4402B, replace the main hydrogen seal oil pump, conduct control rod scram time testing, and perform turbine valve testing. The unit returned to full power the following day. One week later, operations personnel lowered reactor power to 525 MWe to perform a control rod pattern adjustment. Unit 1 operated at full power until May 20, when operators identified an increase in offgas system radiation levels. Due to the potential for leaking fuel, engineering placed restrictions on control rod movement. The restrictions resulted in reactor power decreasing to 99 percent by May 25 when engineering personnel worked with the operations staff to lower Unit 1 power to 55 percent to conduct flux suppression testing. The suppression testing identified two separate core regions that likely contain failed fuel. Unit 1 returned to full power on May 28. On June 1 operations personnel lowered reactor power by 10 percent to conduct control rod exercising near the failed fuel locations. Unit 1 returned to full power on June 2. Operations personnel conducted turbine valve testing on June 14 which required reactor power to be reduced to 790 MWe for approximately 4 hours. Unit 1 operated at full power for the remainder of the inspection period.

Unit 2 began the inspection period at criticality following a forced shutdown to repair an electro hydraulic control fluid leak and the 3E power operated relief valve. Nine hours after placing the turbine on line, operations personnel took the turbine off line due to a leak downstream of the turbine control valve on the B main steam line. At 7:16 p.m. on April 3, operations personnel placed the Unit 2 turbine on line and returned the unit to full power. Two days later, operations personnel inserted a manual scram due to a high reactor water level condition. On April 6 operations personnel placed the Unit 2 turbine on line. Unit 2 returned to full power on April 7, 2002. About 1 month later, operations personnel reduced power to approximately 550 MWe to replace the main hydrogen seal oil pump and returned to power later the same day. From May 24 - 26, reactor power was reduced to 550 MWe to conduct control rod scram time testing, replace the main hydrogen seal oil pump, and perform a rod pattern adjustment. Unit 2 returned to full power following these activities. On June 2 operations personnel lowered reactor power to approximately 450 MWe to perform a control rod pattern adjustment. Reactor power was returned to normal levels on June 4. On June 7, June 18, and June 20, unexpected changes in reactor power, reactor pressure, reactor vessel level, and main steam line flow occurred due to an issue with the reactor vessel internals. Unit 2 operated at near full power levels for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed documents supporting the operation of the Service Water and Torus Cooling Systems including the status of open issues which might impact hot weather operation. The inspectors also reviewed plant wide actions taken to prepare for adverse weather, the status of planned actions, and the related procedures in place. The readiness of plant systems was discussed with the staff assigned to manage hot weather preparations.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors verified the system alignment of the following mitigating systems during the period:

- Unit ½ emergency diesel generator;
- Unit 1 reactor core isolation cooling system; and
- Unit 1 high pressure coolant injection system

The inspectors conducted walkdowns while redundant equipment was out-of-service for maintenance activities. The inspectors verified that the as-found system configuration and operating parameters supported the continued ability of the system to perform its intended functions. The inspectors accomplished the verifications by comparing the as-found configuration of the accessible portions of the listed systems to the configuration specified in the respective Quad Cities operating procedures. The inspectors reviewed design and licensing information and discussed system configuration and performance with licensee personnel.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors walked down the following risk significant areas to identify any fire protection degradations:

- Fire Zone 1.1.1.3 Unit 1 Reactor Building Mezzanine;
- Fire Zone 1.1.1.4 Unit 1 Reactor Building 3rd Floor;
- Fire Zone 1.1.1.5 Unit 1 Reactor Building 4th Floor East;
- Fire Zone 11.1.1.A 1D Residual Heat Removal Service Water and U1 Diesel Generator Cooling Water Pump Vault;
- Fire Zone 11.1.1.C 1A Residual Heat Removal Service Water Pump Vault;
- Fire Zone 11.1.2.A 2D Residual Heat Removal Service Water Pump Vault;
- Fire Zone 11.1.2.B 2B and C Residual Heat Removal Service Water Pump Vault;
- Fire Zone 11.1.2.C 2A Residual Heat Removal Service Water Pump, U2 Diesel Generator Cooling Water Pump Vault;
- Fire Zone 11.2.1 1B Core Spray Room;
- Fire Zone 11.2.2 1B Residual Heat Removal Room;
- Fire Zone 11.2.3 1A Core Spray Room; and
- Fire Zone 11.2.4 1A Residual Heat Removal Room

The inspectors placed an emphasis on control of transient combustibles and ignition sources; the material condition, operational lineup, and operational effectiveness of the fire protection systems, equipment, and features; and the material condition and operational status of fire barriers used to prevent fire damage or fire propagation.

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 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 Measures (71111.06)

a. Inspection Scope

The inspectors reviewed Quad Cities Abnormal Procedure (QCOA) 0010-16, "Flood Emergency Procedure," to determine internal and external design flood levels for the site and areas of the plant containing equipment important to safety. The inspectors performed a detailed walkdown of flood protection features for the residual heat removal service water pump vaults and the Unit 1 and Unit 2 core spray pump rooms. The pump rooms contained safety-related mitigating systems susceptible to flooding from both internal and external sources. During the walkdown the inspectors verified equipment below the flood line was sealed; no holes or unsealed penetrations in floors and walls existed between flood areas; watertight doors between flood areas were maintained and in good material condition; and common drain systems and sumps, including floor drain piping and check valves were operable where credited for flood area isolation.

The inspectors verified that the licensee was able to perform the actions specified in QCOA 0010-16, "Flood Emergency Procedure." The inspectors confirmed availability of a pump and equipment designated to provide makeup water to the fuel pool in the event of an external flood in excess of 594 feet above mean sea level.

The inspectors reviewed the corrective actions program database for past flooding events and documentation of previous NRC findings associated with flood protection. The inspectors verified that the licensee entered problems into their corrective action program and the problems were properly addressed for resolution.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On April 15, 2002, the inspectors observed licensed operator requalification training conducted in accordance with Operating Exam Number Three Guide, “Main Steam Line Flow Instrument Failure/Large Loss Of Coolant Accident/Reactor Pressure Vessel Flooding.”

The inspectors verified crew performance in terms of clarity and formality of communication; the ability to take timely action; the prioritizing, interpreting, and verifying of alarms; the correct use and implementation of procedures; timely control board operation and manipulation; and the shift manager’s ability to identify and implement Technical Specification and emergency plan actions.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed the licensee’s implementation of maintenance rule requirements, including a review of scooping, goal-setting, performance monitoring, short-term and long-term corrective actions, and current equipment performance for the following systems:

- Automatic Depressurization System;
- Reactor Protection System; and
- Division II Alternating Current

The inspectors independently verified that the systems were appropriately classified as (a)(1) or (a)(2); that performance criteria for systems classified as (a)(2) were appropriate; and that the corrective actions for systems classified as (a)(1) were adequate.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation of risk, activity scheduling, configuration control, and emergent work to ensure that plant risk was appropriately managed. The inspectors verified that licensee actions, such as establishing compensatory actions, minimizing the duration of the activity, obtaining appropriate management approval, and informing appropriate plant staff to address increased online risk during these periods were accomplished when needed. The following work week activities were reviewed:

Work Week Reviewed	Systems Out of Service During Work Week
Week of April 6, 2002	Unit 1 emergency diesel generator, 1B residual heat removal valve, reactor core isolation cooling, high pressure coolant injection, and emergent work on the electro-hydraulic control system
Week of April 13, 2002	1B control room emergency ventilation, 2B residual heat removal, 2C and 2D residual heat removal service water pumps, and reactor core isolation cooling
Week of April 20, 2002	Unit 1 high pressure coolant injection, dredging in the intake bay, and switchyard breaker 4-6
Week of May 4, 2002	Unit 1 reactor core isolation cooling, ½ B standby gas treatment, 1A core spray, and dredging in the intake bay.
Week of May 13, 2002	1B residual heat removal pump, a station blackout diesel generator, Unit 1 main hydrogen seal oil pump, ½ emergency diesel generator, and 2A residual heat removal

Week of May 20, 2002	Unit 2 high pressure coolant injection, Unit 2 high pressure coolant injection room cooler, 2A stator water heat exchanger, 2A control rod drive pump, and testing of the Unit 2 group 3 containment isolation valves

b. Findings

No findings of significance were identified.

1R14 Non-Routine Evolutions (71111.14)

.1 Manual Reactor Head Vent Isolation Valves Found Open During Unit 2 Startup Activities

a. Inspection Scope

The inspectors reviewed Condition Report 97694, "Unit 2 Reactor Head Vent Bypass Valves Found Open," the apparent cause evaluation, and associated procedures, and interviewed operations personnel to determine the circumstances which led to starting up and pressurizing the Unit 2 reactor to 50 pounds with the reactor head vent isolation valves open.

b. Findings

The inspectors identified one green finding involving a non-cited violation for a lack of communications between operations personnel and an administrative senior reactor operator's failure to participate in a formal shift turnover which resulted in operations personnel commencing a Unit 2 reactor startup with the manual reactor head vent isolation valves in the open position

Background

On March 4, 2002, operations personnel received alarm 902-4, "Unit 2 Drywell Equipment Drain Sump High Temperature." Operations and radiation protection personnel responded to the drywell to measure the temperature of pipes that interface with the drywell equipment drain sump. The operators in the drywell identified that the common drain line downstream of the reactor head vents had reached 210 degrees Fahrenheit. One operator and one radiation protection technician proceeded to the drywell basement to inspect the drywell equipment drain sump. This inspection was unable to be completed due to the amount of steam in the drywell basement. The remaining operator and radiation technician continued to perform general leak inspections and identified that the manual reactor head vent isolation valves had been left open. The operator closed the head vent isolation valves and the steam in the drywell basement diminished. No other sources of leakage were identified.

The licensee determined that the manual reactor head vent isolation valves had been left open due to inadequate communications between operations personnel and the failure to perform an adequate turnover. During the outage, multiple work activities and surveillance tests were conducted which required the head vent isolation valves to be open. Although the restoration steps for many of the work activities or surveillance tests directed that the head vent isolation valves be closed, operations personnel took appropriate steps to leave the valves open to allow continued surveillance testing. In addition to documenting the status of the valves within specific surveillance procedures, operations personnel placed an equipment status tag on the control room panels to alert operations personnel to the abnormal condition of the head vent isolation valves.

On March 3, 2002, a unit nuclear station operator (licensed reactor operator) noticed the head vent isolation valve equipment status tag on the control room panels. The nuclear station operator removed the equipment status tag and handed it to the administrative senior reactor operator (Admin SRO). After the head vent isolation valves were discovered open, the Admin SRO stated that he believed the nuclear station operator had said that the equipment status tag had been resolved. No action was taken to confirm the information communicated by the nuclear station operator or to verify the position of the head vent isolation valves. In addition, the Admin SRO had not participated in a formal turnover prior to assuming his duties as part of the operating shift. As a result, the Admin SRO was not aware of previous discussions regarding equipment status tag resolution. This contributed to removing the equipment status tag even though no action had been taken to close the head vent isolation valves.

Significance Evaluation

The inspectors determined that the safety significance of the manual reactor head vent isolation valves being left open during reactor startup was more than minor because if left uncorrected, the issue may become more of a safety concern due to leakage from the common drain line possibly being masked by the feedwater system and because the issue impacted the integrity of the reactor coolant system. The inspectors continued to screen this issue using the Phase 1 screening worksheet. This worksheet was used rather than screening the issue using the Shutdown Significance Determination Process because operations personnel had secured the residual heat removal system from shutdown cooling. The inspectors determined that the Phase 1 screening worksheet was not an adequate tool to screen this issue since the At Power Significance Determination Process assumed that the reactor was operating at normal temperatures and pressures. The inspectors discussed the risk tool inadequacies with the senior reactor analyst who agreed to perform a bounding Phase 2 analysis.

The senior reactor analyst determined that the Significance Determination Process Worksheet for transients should be evaluated and determined that the safety significance of the manual reactor head vent isolation valves being left open during reactor startup was very low (Green) because the leak created by the valves being left open was not of a sufficient size to impact the availability of the power conversion system function or other available mitigating systems equipment.

Enforcement

Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in

Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, Section 1g requires procedures for shift relief and turnover. Procedure OP-AA-112-101, “Shift Turnover and Relief,” is the licensee’s procedure addressing the requirements of Regulatory Guide 1.33, Section 1g. Step 3.1 of Procedure OP-AA-112-101 states that all shift personnel are responsible for reviewing and understanding the logs and checklists applicable to their shift position before assuming the shift. The inspectors determined that the failure of the Admin SRO to participate in a shift turnover that included a review of logs and checklists applicable to the Admin SRO position prior to assuming the shift was a violation of Technical Specification 5.4.1. However, this violation is not being cited in accordance with Section VI.A.1 of the NRC’s Enforcement Policy **(NCV 50-265/02-05-01)**. This issue was included in the licensee’s corrective action program as Condition Report 112360.

.3 Unexpected Change in Unit 2 Operating Parameters

a. Inspection Scope

On June 7 operations personnel identified that main steam line A flow had increased from 2.95 to 3.05 million pounds per hour and that flow in the three remaining steam lines decreased. Approximately 2-3 minutes later, operations personnel observed reductions in reactor pressure, reactor vessel level, reactor power, and feedwater flow. The inspectors reviewed operator logs, available plant data, and procedures to determine the appropriateness of operator actions in response to this transient. The inspectors performed similar reviews for additional transients which occurred on June 18 and June 20. The inspectors observed multiple meetings between the licensee and General Electric which were held to determine the cause of the transient and corrective actions. Personnel from the Office of Nuclear Reactor Regulation, Region III, and the resident inspector office also participated in a conference call with the licensee regarding the information provided by General Electric, the licensee’s operability evaluation, and potential impacts on continued operation of Unit 2.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

.1 Missing or Inadequate Seismic Restraining Clamps on Multiple Control Rod Drive Accumulators

a. Inspection Scope

The inspectors reviewed the operability evaluation performed for Condition Report 98263, “Unauthorized Retaining Clamps Used for Hydraulic Control Unit Accumulators,” to determine the impact that the unauthorized clamps had on system operability.

b. Findings

One Green finding involving a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified due to the failure to properly evaluate the replacement of the required seismic steel band clamps with hose clamps.

Background

At Quad Cities each control rod drive hydraulic accumulator should have two steel bands installed to ensure that this portion of the control rod drive system remains intact during and following a seismic event. On February 28, 2002, Quad Cities personnel received a nuclear operations notification (part of the station's operating experience process) describing that one or both of the steel bands were missing on multiple accumulators at Oyster Creek Station. The operating experience coordinator reviewed the notification in accordance with Procedure RS-AA-115, "Operating Experience," and concluded that the potential missing steel clamps did not impact the operability of the control rod drive system. As a result, the operating experience coordinator assigned an action item to reactor engineering to review the notification within 30 days.

On March 7, 2002, the inspectors at Dresden Station contacted the inspectors at Quad Cities Station and informed them that engineers had identified missing clamps on several accumulators at Dresden Station. The Quad Cities Station resident inspectors contacted the shift manager to determine if he was aware that the control rod drive accumulators on both units may be degraded. The inspectors were also concerned that if missing clamps were identified on Unit 2, operations personnel may have changed operating modes with inoperable accumulators which is prohibited by Technical Specifications.

Following discussions with the inspectors, the shift manager learned that engineering personnel had conducted a walk down of each unit's control rod drive accumulators. Engineering personnel identified two control rod drive accumulators on Unit 1 (34-43 and 46-27) and two on Unit 2 (22-59 and 38-03) that either had hose clamps installed instead of the required steel seismic bands or were missing clamps. The inadequate or missing clamps were immediately replaced with the appropriate steel band clamps. Engineering personnel also completed an operability evaluation to determine whether the accumulators were operable prior to the clamps being replaced.

The inspectors reviewed the operability evaluation and agreed with the licensee's conclusion that the accumulators remained operable. However, the inspectors questioned the licensee to determine if a parts evaluation addressing the change in design had been completed prior to the installation of the hose clamps. The licensee was unable to find any documentation that justified the design change. The licensee wrote Condition Report 104321 to document the missing design change evaluation.

Significance Evaluation

The inspectors determined that the failure to ensure an adequate design review was performed prior to changing the design of a safety related component was more than minor since if left uncorrected, it could become a more significant safety concern and because the issue could affect the reliability of a mitigating system. The inspectors used the Significance Determination Process Phase 1 Screening Worksheet and determined that this issue was of very low safety significance (Green) because the design deficiency did not result in a loss of function as described in Generic Letter 91-18, “Resolution of Degraded and Non-Conforming Conditions and on Operability.”

Enforcement Actions

10 CFR 50, Appendix B, Criterion III, “Design Control,” requires that measures shall be established for the selection and review for suitability of application of materials, parts, and equipment that are essential to the safety-related functions of structures, systems, and components. The failure to ensure that the selection and suitability of hose clamps for the control rod drive hydraulic accumulators was appropriate instead of the steel band clamps was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III **(NCV 50-254/02-05-03; 50-265/02-05-03)** in accordance with Section VI.A.1 of the NRC’s Enforcement Policy. The issue was entered into the licensee’s corrective action program as Condition Report 104321.

.2 Review of Other Operability Determinations

a. Inspection Scope

The inspectors reviewed the operability evaluations associated with a degraded 1A residual heat removal system heat exchanger, the lack of gland seal water to the Unit 1 diesel generator cooling water pump, degraded auxiliary contacts on multiple motor control centers, and unexpected power changes due to possible dryer degradation. A list of the documents reviewed by the inspectors can be found in the List of Documents Reviewed section of this report.

The inspectors verified that operability evaluations were performed when required and that completed evaluations were technically adequate, justified continued operation, considered other degraded conditions where applicable, and referenced applicable sections of the Updated Final Safety Analysis Report and other design basis documents.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed and observed the following post-maintenance testing activities involving risk significant equipment in the Mitigating Systems and Barrier Integrity Cornerstones:

- Work Order 423819 Unit 2 “3E” Power Operated Relief Valve;
- Work Order 379753 Unit ½ Emergency Diesel Generator;
- Work Order 408294 Unit 1 High Pressure Coolant Injection; and
- Work Order 452432 Unit 1 B Residual Heat Removal Service Water System

The inspectors verified that the post maintenance tests were adequate for the scope of the maintenance work performed, that the test acceptance criteria were clear, and that the tests demonstrated operational readiness consistent with design and licensing basis documents. The inspectors also verified that the impact of the testing had been properly characterized during the pre-job briefing; the tests were performed as written; all testing prerequisites were satisfied; and that the test data was complete. Following the completion of the tests, the inspectors verified that test equipment was removed and that the systems were returned to their normal standby configuration.

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 packages for the tests listed below related to systems in the Mitigating Systems and Barrier Integrity Cornerstones:

- QCIS 0700-22, “Unit 1 Division II Power Operation APRM Functional Test”;
- QCOS 1400-08, “Core Spray System Power Operated Valve Test”;
- QCOS 6600-41, “Unit 1 Diesel Generator Load Test”;
- QCOS 6600-42, “Unit 2 Diesel Generator Load Test”;
- QCOS 6600-03, “Diesel Fuel Oil Transfer Pump Monthly Operability”;
- QCOS 6600-02, “Diesel Generator Air Compressor Operability”;
- QCOS 0203-07, “Unit 2 Auto Blowdown Initiation Logic Test”;
- CY-QC-120-600, “Off-Gas Sampling”;
- CY-QC-130-401, “Off-Gas Isotopic Analyses Recombiner Outlet and Adsorber Inlet Samples”;
- QCOS 1600-45, “Unit 2 Primary Containment Isolation Group 3 Test”; and
- QCOS-1000-06**,** ”Residual Heat Removal/LOOP Operability Test”

The inspectors verified that the structures, systems, and components selected were capable of performing their intended safety function and that the surveillance tests satisfied the requirements contained in Technical Specifications, the Updated Final Safety Analysis Report, and licensee procedures. During surveillance testing observations, the inspectors verified that the test demonstrated operational readiness consistent with design and licensing basis documents and that the test acceptance criteria were clear. The inspectors also verified that the impact of the testing had been properly characterized during the pre-job briefing; the test was performed as written; the test data was complete and met the requirements of the testing procedure; and the test equipment range and accuracy was consistent with the application. Following test completion, the inspectors verified that the test equipment was removed and that the system was returned to its normal standby configuration.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed Design Change Package 330658 used to modify and repair feedwater manual isolation valve 2-0220-057A and the associated 10 CFR 50.59 screening. The inspectors compared the contents of the design change package and the 50.59 screening to design basis information contained in the Updated Final Safety Analysis Report, Technical Specifications, and the Technical Requirements Manual. The inspectors also reviewed the design change package to ensure the applicable American Society of Mechanical Engineers code requirements were met during the repair.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors reviewed Revision 14 of the Quad Cities Nuclear Power Station Annex to the Exelon Nuclear Standardized Radiological Emergency Plan to determine whether changes identified in Revision 14 reduced the effectiveness of the licensee's emergency planning, pending onsite inspection of the implementation of these changes.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

.1 Review of April 19, 2002, Emergency Preparedness Drill Activities

a. Inspection Scope

The inspectors observed the drill scenario and the licensee's emergency preparedness activities from the simulator and the technical support center. Specific activities observed or assessed included the accuracy and timeliness of emergency classifications, notifications, and protective action recommendations and the thoroughness of the licensee's critique. The inspectors also reviewed the licensee's determination of successful and failed opportunities under the Drill and Exercise Performance Indicator to ensure the determinations were made in accordance with Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

.2 Review of June 12, 2002 Emergency Preparedness Pre-Exercise

a. Inspection Scope

The inspectors observed the licensee's emergency preparedness pre-exercise from the simulator and technical support center. The scenario began with an earthquake which caused operations personnel in the simulator to declare an unusual event. Once personnel confirmed that the acceleration caused by the earthquake was greater than .1g, the shift manager upgraded the event to the alert status. A site emergency was declared when two of the three fission product barriers were lost. Emergency operations facility personnel upgraded the event classification to a general emergency following the identification that the third fission product barrier may be lost. The inspectors assessed the accuracy and timeliness of emergency classifications, notifications, and protective action recommendations to ensure that successful and failed opportunities were appropriately captured for inclusion in the specific NRC performance indicator. The inspectors also observed the licensee's critique to ensure that items identified by the inspectors were also identified by the licensee.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Controls To Radiologically Significant Areas (71121.01)

.1 Control of Non-Fuel Materials Stored in the Spent Fuel Pool

a. Inspection Scope

The inspector evaluated the licensee's procedure and practices for the control of highly activated or contaminated materials (non-fuel) stored within the spent fuel pool or other storage pools in order to verify that controls for underwater storage of non-fuel materials were adequate, the materials were accounted for and that the administrative and physical controls for the underwater storage of non-fuel materials were consistent with the licensee's procedure, Regulatory Guide 8.38, "Control of Access to High and Very High Radiation Areas in Nuclear Plants" and Information Notice 90-33, "Sources of Unexpected Occupational Radiation Exposures at Spent Fuel Storage Pools." The Spent Fuel Storage Pool Inventory Control and Audit Procedure along with the Spent Fuel Storage Pool Inventory Log were reviewed; radiation protection and reactor services staff were interviewed; and a walkdown of the refuel floor was conducted.

b. Findings

No findings of significance were identified.

.2 Identification and Resolution of Problems

a. Inspection Scope

The inspector evaluated the effectiveness of the station's problem identification and resolution processes to identify, characterize and prioritize problems, and to develop and implement corrective actions. The evaluation included: (1) the results of a focus area self-assessment of the as-low-as-reasonably-achievable (ALARA) Planning and Control Program performed during 2002; (2) a Nuclear Oversight continuous assessment report along with field observation reports of the Radiation Protection Program (Access Control and ALARA programs) that were completed in calendar years 2001 and 2002; and (3) the licensee's condition report (CR) database and individual CRs related to the Access Control and ALARA programs for years 2001-2002.

The licensee's corrective action program for Radiation Protection was evaluated to verify that problems were appropriately prioritized and resolved in a timely manner, and commensurate with their importance based on safety and risk. This evaluation included procedure and documentation reviews, discussions of the program with cognizant licensee personnel, and observing management meetings in which condition reports were evaluated.

b. Findings

No findings of significance were identified.

20S2 ALARA Planning and Controls (71121.02)

.1 Source Term Reduction and Control

a. Inspection Scope

The inspector reviewed the status of the station's source term reduction program focusing on those initiatives having a major impact on outage dose. This included cobalt/stellite reduction, chemistry management, chemical decontamination, permanent shielding, hydrolasing/flushing evolutions, shutdown practices to minimize source term transportation, and system enhancements. The inspector also assessed the general trend of the station's total source term to evaluate the effectiveness of the station's source term reduction plan.

b. Findings

No findings of significance were identified.

.2 Declared Pregnant Workers

a. Inspection Scope

The inspector reviewed the station's dose minimization controls used for declared pregnant workers. Specifically, the inspector reviewed the licensee's adherence to the requirements contained in 10 CFR 20.1208 by examining the licensee's fetal protection program procedure for tracking radiological exposure to the embryo/fetus, and the administrative and ALARA controls that could be used by the licensee to minimize the dose to the embryo/fetus of a declared pregnant worker.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation (71122.02)

.1 Shipment Records

a. Inspection Scope

The inspector reviewed one radioactive material and radwaste shipment manifest and associated records for a non-excepted shipment (Low Specific Activity II) from April 2002. The review was performed to verify compliance with NRC requirements contained in 10 CFR Parts 20, 61, and 71, and the Department of Transportation (DOT) requirements of 49 CFR Parts 172 and 173. The records were reviewed to verify that package and transport vehicle surveys satisfied DOT requirements, and that shipment manifests were completed in accordance with the regulations and included appropriate emergency response information.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP1 Access Authorization (AA) Program (Behavior Observation Only) (71130.01)

a. Inspection Scope

The regional security inspector interviewed five supervisors and five non-supervisors (both licensee and contractor employees) to determine their knowledge level and practice of implementing the licensee's behavior observation program responsibilities. Selected procedures pertaining to the Behavior Observation Program and associated training activities were also reviewed. Also licensee fitness-for-duty semi-annual test results were reviewed. In addition, the inspector reviewed a sample of licensee self-assessments, audits, and security logged events. The inspector also interviewed security managers to evaluate their knowledge and use of the licensee's corrective action system.

b. Findings

No findings of significance were identified.

3PP2 Access Control (Identification, Authorization and Search of Personnel, Packages, and Vehicles) (71130.02)

a. Inspection Scope

The regional security inspector reviewed the licensee's protected area access control testing and maintenance procedures. The inspector observed licensee testing of all access control equipment to determine if testing and maintenance practices were performance based. On two occasions, during peak ingress periods, the inspector observed in-processing search of personnel, packages, and vehicles to determine if search practices were conducted in accordance with regulatory requirements. Interviews were conducted and records were reviewed to verify that security staffing levels were consistently and appropriately implemented. Also the inspector reviewed the licensee's process for limiting access to only authorized personnel to the protected area and vital equipment by a sample review of access authorization lists and actual vital area entries. The inspector reviewed the licensee's program to control hard-keys and computer input of security-related personnel data.

The regional security inspector reviewed a sample of licensee self-assessments, audits, maintenance request records, and security logged events for identification and resolution of problems. In addition, the inspector interviewed security managers to evaluate their knowledge and use of the licensee's corrective action system.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Review of Initiating Events Cornerstone Performance Indicators

a. Inspection Scope

The inspectors reviewed the licensee's performance indicator data sheets, operator logs, monthly operating reports, licensee event reports, previous inspection reports and condition reports and conducted independent calculations to verify, for each unit, the Reactor Scrams and Reactor Scrams with Loss of Heat Removal performance indicators for the period of July 2001 through March 2002, and the Unplanned Power Changes per 7000 Critical Hours performance indicator for the period of July 2001 through May 2002.

b. Findings

No findings of significance were identified.

.2 Review of Physical Security Cornerstone Performance Indicators

a. Inspection Scope

The regional security inspector verified the data for the Physical Protection Performance Indicators pertaining to Fitness-For-Duty Personnel Reliability, Personnel Screening Program, and Protected Area Security Equipment. Specifically, a sample of plant reports related to security events, security shift activity logs, fitness-for-duty reports, and other applicable security records were reviewed for the period between November 2000 and December 2001.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

a. Inspection Scope

The inspectors reviewed a sample of condition reports, cause determinations, and corrective actions listed in the list of documents reviewed section of this report to determine if the licensee was identifying human performance issues and taking corrective actions commensurate with the significance of the issues. The inspectors also evaluated the licensee's extent of condition review, potential generic implications, and common cause determination.

b. Findings

The inspectors determined that a large number of human performance related problems had occurred in 2002. Although the human performance problems were identified through self-revealing plant issues or events, the licensee initiated condition reports to evaluate the root, apparent, and/or contributing causes for most issues and developed actions to correct each condition.

In January 2002 the licensee initiated Condition Report 92430 to document an increase in human performance problems. The prompt corrective actions consisted of instituting a temporary program to make all employees more aware of the importance of fundamentals when performing work activities. The inspectors determined that human performance related problems continued to occur in February 2002 indicating that the temporary program may not have been effective in reducing the number of human performance related issues at the station.

In March 2002 the licensee conducted a common cause review for Condition Report 92430 and determined that a large portion of the human performance problems were related to substandard verification practices such as self-check and peer-check. Complacency with standards for items such as pre-job briefs was also determined to be a contributor. The corrective actions developed as part of the common cause review included developing and implementing a plan to increase the use of fundamentals known to prevent human performance issues. The licensee also instituted human performance review boards to identify human performance issues that had resulted in plant issues or events.

On March 14 the licensee expanded the common cause analysis performed for Condition Report 92430 to include February 2002 data and determine any relationships between the human performance problems. The expanded common cause report was completed on May 15, 2002. The human performance coordinator determined that the causes for the February 2002 human performance issues were different than those identified during the review of January 2002 events. Specific causes included weaknesses in work planning, questioning attitude, procedure adherence, self-check, and peer-check. In response to the new issues, the licensee implemented a paired observation program to provide employees with real-time feedback associated with their work activities. A short time later, senior licensee management determined that individuals performing as assessors in the paired observation program were not as critical as expected. This was of concern since a lack of criticalness may impact the effectiveness of the licensee's corrective actions and result in no significant changes in human performance. At the conclusion of the inspection period, the licensee had taken actions to improve the feedback provided as part of the paired observation program. The effectiveness of these actions was unable to be determined.

The inspectors conducted an independent review of condition reports and agreed with the licensee's assessment regarding the causes for the recent human performance problems. The inspectors determined that the licensee was documenting human performance related issues as part of the corrective action program and taking actions to correct the conditions. Due to the fact that human performance related problems continue to occur, and the short amount of time the licensee's corrective actions have been in effect, the inspectors were unable to determine the effectiveness of the licensee's proposed corrective actions.

4OA3 Event Followup (71153)

.1 Reactor Scram Caused by Design Weakness in Digital Feedwater Control System and Unintended Ground of Plant Equipment

a. Inspection Scope

On April 5, 2002, operations personnel manually scrammed the Unit 2 reactor due to high reactor vessel water level. The inspectors observed operator and plant performance from the control room to ensure that the response to the transient was in accordance with procedures. The inspectors reviewed plant parameters, the operation of mitigating systems, the integrity of fission product barriers and confirmed that the licensee properly reported the event as required by 10 CFR 50.72.

b. Findings

One Green finding was identified due to the failure to properly design the digital feedwater level control system to withstand an inadvertent grounding of plant instrumentation.

Background

At 10:00 a.m. on April 5, 2002, operations personnel granted permission for two instrument maintenance technicians to perform instrument surveillance QCIS 0600-02, "Unit 2 Reactor Pressure 0 to 1200 psig Indication Calibration," on pressure transmitter 2-0647A. Personnel at the digital feedwater level control system operator station placed transmitter 2-0647-A in the "calibrate mode." The use of the "calibrate mode" allowed the output of the pressure transmitter to be disconnected from the control system logic. With the pressure transmitter's output disconnected from the control system logic, licensee personnel believed that the calibration of the transmitter could continue without impacting the digital feedwater control system.

Approximately 4 minutes later, operations personnel detected a "hard failure" signal error on the 2A reactor feed pump suction pressure transmitter. Total indicated feedwater flow dropped from 10.81 million pounds per hour (mlb/hr) to 9.73 mlb/hr. The digital feedwater level control system continued to show a reduction in total indicated feedwater flow to 4.85 mlb/hr. The apparent mismatch between steam flow and feedwater flow caused the 2A and 2B feedwater regulating valves to go to 80 percent open. Opening of the feedwater regulating valves caused the total indicated feedwater flow to increase to 6.64 mlb/hr. Although the digital feedwater control system initially displayed that total indicated feedwater flow had dropped from 10.81 mlb/hr to 9.73 mlb/hr, total feedwater flow had actually increased from 10.81 mlb/hr to 13.5 mlb/hr. The large increase in actual feedwater flow resulted in operations personnel manually scramming the reactor after reaching the pre-established manual scram criteria.

Root Cause

In February 2002 Quad Cities Station installed a digital feedwater level control system on Unit 2. The licensee believed the digital control system was designed such that the system would switch from three-element to single-element control when the current signal in an instrument loop dropped to less than 2 milliamps. The licensee identified that the vendor supplied fuse holders installed as part of the digital feedwater level control system contained light emitting diodes (for fuse failure identification) wired in parallel with the fuses. On April 5, 2002, the instrument maintenance technicians made a human performance error when they grounded pressure transmitter 2-0647-A during calibration. The grounding caused the fuse for the instrument loop containing pressure transmitter 2-0647-A, the 2A reactor feed pump suction pressure transmitter, and the 2A reactor feed pump feedwater flow transmitter to blow. The blown fuse should have resulted in a reduction of the instrument loop current to less than 2 milliamps. However, the licensee discovered that following a fuse failure, a “sneak” current continued to supply the light emitting diodes on the fuse holder such that instrument loop current remained greater than 2 milliamps and prevented the digital feedwater level control system from converting to single-element control.

Significance Evaluation

The inspectors determined that this issue was more than minor since it had an actual impact on safety, resulted in an increase in the transient initiating event frequency, and effected the function of a mitigating system. The inspectors evaluated this issue using the Phase 1 Significance Determination Process Screening Worksheet and determined that the failure to adequately design the digital feedwater level control system to withstand an inadvertent grounding of an instrument under calibration required a Phase 2 analysis because the issue contributed to the likelihood of a reactor scram and the likelihood that mitigating equipment or functions may not be available. The inspectors performed the Phase 2 risk analysis and determined that this issue was of very low safety significance (Green) because the feedwater system could be recovered even if reactor vessel water level exceeded Level 8 and adequate mitigating systems equipment remained available to place and maintain the plant in a stable condition **(FIN 50-265/02-05-04)**.

Enforcement

The inspectors determined that no violations of NRC requirements occurred during the design of the digital feedwater system or during the calibration of pressure transmitter 2-0647-A on April 5, 2002, due to the digital feedwater level control system being non safety-related.

.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 50-254/00-001-01: Automatic Reactor Scram from Low Reactor Vessel Level. The inspectors reviewed the licensee’s initial event report as part of the inspection activities documented in Sections 1R14 and 4OA3 of Inspection Report 50-254/00-00; 50-265/00-20. On April 29, 2002, the licensee submitted a revision to the event report to document pertinent root cause and corrective action information. The inspectors reviewed the revised event report and found that the new information did not change the inspectors’ initial assessment of licensee performance during the reactor scram.

(Closed) Licensee Event Report 50-254/00-002-01: Inadequate Calibration of Post Accident Torus Temperature Monitors. The inspectors documented one green finding involving a Non-Cited Violation during a review of the initial event report (see Inspection Report 50-254/00-15; 50-265/00-15). On April 29, 2002, the licensee submitted a revised event report to incorporate pertinent root cause and corrective action information. The inspectors reviewed the revised event report and determined that the new information did not change the inspectors’ initial assessment of the event.

(Closed) Licensee Event Report 50-265/02-001-00: High Pressure Coolant Injection System Uncoupled Above 150 psig due to Misapplication of Technical Specifications. On March 4, 2002, operations personnel increased reactor pressure above 150 psig with the HPCI turbine disconnected from the pump. The decision to raise reactor pressure above 150 psig was contrary to Technical Specification 3.0.4. The inspectors documented the circumstances surrounding this event, and the risk associated with exceeding 150 psig reactor pressure with the HPCI turbine disconnected, in Section 4OA7 of this report.

(Closed) Licensee Event Report 50-265/02-002-00: Manual Scram due to Reactor Vessel Level Transient as a Result of a Digital Feedwater Level Control System Design Error. On April 5, 2002, operations personnel inserted a manual reactor scram due to increasing reactor vessel water level. The licensee determined that the increasing level was caused by a digital feedwater control system design error in conjunction with inadvertent grounding of a pressure transmitter during an instrument maintenance surveillance. The inspectors documented the circumstances surrounding this event, and the risk associated with this initiating event, in Section 4OA3 of this report.

4OA5 Other

.1 (Closed) Unresolved Item 50-254/01-05-02; 50-265/01-05-02: This unresolved item involved the licensee's methods for changing maintenance rule performance criteria, the failure to update the Probabilistic Risk Assessment Report every two years as required by procedure, and the decision not to establish condition monitoring criteria for maintenance rule components when maintenance rule performance criteria were too small to be effectively monitored. The Office of Nuclear Reactor Regulation (NRR) determined that the licensee's use of Electric Power Research Institutes (EPRI) TR-105369, "Probabilistic Safety Assessment Application Guide," when changing maintenance rule performance criteria was acceptable because this methodology generally provides conservative results if applied correctly. As stated in Inspection Report 50-254/01-05; 50-265/01-05, the inspectors reviewed the EPRI guidance and had no concerns with the licensee's application of the guidance. With regards to the failure to update the Probabilistic Risk Assessment Report every 2 years as required by procedure, NRR determined that no regulatory requirement existed that required an update to be made. However, should the licensee request a license amendment, a Notice of Enforcement Discretion, or some other relief from regulatory requirements using the existing Probabilistic Risk Assessment Report, the Nuclear Regulatory Commission would expect the licensee to provide an updated version of the Probabilistic Risk Assessment information. Lastly, the inspectors were concerned with the licensee's decision not to establish condition monitoring criteria as discussed in Regulatory Guide 1.160. NRR determined that a licensee's conformance to Regulatory Guide 1.160 was not required by regulations. Therefore, the licensee's decision to not establish condition monitoring criteria was not a violation of regulatory requirements.

.2 (Closed) Unresolved Item 50-254/01-17-02; 50-265/01-17-02: This unresolved item involved the impact that the potential for lifting of standby liquid control system relief valves had on the licensee's continued compliance with the Anticipated Transient Without Scram (ATWS) Rule, 10 CFR 50.62, and standby liquid control system operability as defined in Technical Specification 3.1.7. As stated in Inspection Report 50-254/01-17; 50-265/01-17, the inspectors discovered conflicting information regarding the licensee's continued ability to comply with 10 CFR 50.62 and Technical Specification 3.1.7 due to the discovery that the standby liquid control system relief valves may lift during two pump operation required by the ATWS rule.

The conflicting information was provided to individuals in the Nuclear Regulatory Commission's Office of Nuclear Reactor Regulation for review. In December 2000 the NRC issued Regulatory Guide 1.186, "Guidance and Examples for Identifying 10 CFR 50.2 Design Bases," which endorsed Appendix B to Nuclear Energy Institute (NEI) Document 97-04, "Design Bases Program Guidelines." The general guidance in Appendix B to NEI 97-04 states that design basis functions are:

> Functions performed by systems, structures and components that are (1) required by, or otherwise necessary to comply with, regulations, license conditions, orders or technical specifications, or (2) credited in the licensee's safety analyses to meet NRC requirements.

Based on the above information, the NRC's position was that although the original Quad Cities design basis did not include ATWS events, these types of events must now be included. The inspectors also used the above information to determine that the lifting of the standby liquid control relief valves resulted in the licensee being outside of their design basis and in non-compliance with the ATWS rule since the system was unable to meet the required injection flow rate and boron concentration during the time the relief valves were lifting.

Part 50.62 to 10 CFR requires, in part, that each boiling water reactor must have a standby liquid control system with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate that the resulting reactivity control was at least equivalent to that resulting from the injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate (boron) solution. The failure to have a standby liquid control system with the capability of injecting into the reactor pressure vessel a borated water solution at such a flow rate that the resulting reactivity control was at least equivalent to that resulting from the injection of 86 gallons per minute of 13 weight percent sodium pentaborate decahydrate (boron) solution was considered a Non-Cited Violation **(NCV 50-254/02-05-05; 50-265/02-05-05)** of 10 CFR Part 50.62. This issue was entered into the licensee's corrective action program as Condition Report Q2001-02901.

The inspectors reviewed the risk significance of this issue and determined that the inability of the standby liquid control system to meet the requirements of the ATWS rule was more than minor because if left uncorrected, the issue would become a more significant safety concern and the issue affected the function of a system or train in a mitigating system. The inspectors screened the issue using the Significance Determination Process and determined the safety significance of this issue to be very low (Green) because the standby liquid control system could be recovered during an ATWS event, cycling of the relief valves would allow a portion of the borated solution to be injected into the reactor pressure vessel, and the licensee was able to demonstrate that they remained within the acceptance criteria of their original ATWS analyses even if no boron solution was injected into the reactor pressure vessel during the relief valve lifts.

The Office of Nuclear Reactor Regulation also determined that although the licensee was not in compliance with the ATWS rule due to the standby liquid control system relief valves lifting, the standby liquid control system remained operable per the requirements of Technical Specification 3.1.7. This determination was based upon information contained in NUREG-1433, "Standard Technical Specifications General Electric Plants," which states that Technical Specification 3.1.7 does not require meeting the requirements of 10 CFR 50.62 to meet the associated Technical Specification Limiting

Condition for Operation. Based upon this information, no violation of Technical Specifications occurred.

4OA6 Meetings

.1 Inspection Period Exit Meeting

The inspectors presented the inspection results to Mr. Tulon and other members of licensee management at the conclusion of the inspection on June 26, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

.2 Interim Exit Meeting

Senior Official at Exit:	Mr. Timothy Tulon, Site Vice President
Date:	April 12, 2002
Proprietary Information:	No
Subject:	Radiological Access Control Program and the ALARA Planning and Controls Program

.3 Interim Exit Meeting

Senior Official at Exit:	Mr. Timothy Tulon, Site Vice President
Date:	April 12, 2002
Proprietary Information:	No
Subject:	Physical Security

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and was a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

Technical Specification 3.0.4 states that when a limiting condition for operation is not met, entry into a mode or other specified condition in the Applicability shall not be made except when the associated actions to be entered permit continued operation for an unlimited period of time. The Applicability section of Technical Specification 3.5.1, "Emergency Core Cooling System - Operating," states that the HPCI system shall be operable in Mode 1 and Modes 2 and 3 when reactor vessel pressure is greater than 150 psig. On March 4, 2002, as described in LER 50-265/02-001-00, operations personnel increased reactor pressure above 150 psig with the HPCI turbine disconnected from the pump. The failure to ensure the HPCI system was operable prior to exceeding 150 psig reactor pressure was considered a Non-Cited Violation of Technical Specification 3.0.4 in accordance with Section VI.A.1 of the NRC's Enforcement Policy **(NCV 50-265/02-05-02)**. This issue was included in the licensee's corrective action program as Condition Report 101320.

The inspectors determined that the failure to have the HPCI turbine connected to the pump when reactor pressure was greater than 150 psig was more than minor because having an inoperable and unavailable mitigating system impacted safety. The inspectors evaluated this issue using a Significance Determination Process Phase 2 risk analysis. The inspectors determined the safety significance of this issue to be very low (Green) because the reactor was at low pressure and adequate mitigating equipment was operable or available.

PARTIAL LIST OF PERSONS CONTACTED

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
K. Hungerford, Wackenhut Project Manager
A. Javorik, Maintenance Manager
K. Leech, Security Manager
K. Moser, Chemistry/Environ/Radwaste Manager
M. Perito, Operations Manager
M. Snow, Nuclear Oversight Manager

NRC

M. Ring, Chief, Reactor Projects Branch 1

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-265/02-05-01	NCV	Failure to Participate in Turnover Contributes to Manual Reactor Head Vent Isolation Valves Being Left Open During Unit Startup
50-265/02-05-02	NCV	Failure to Have Unit 2 HPCI System Operable With Reactor Pressure Greater than 150 psig
50-254/02-05-03; 50-265/02-05-03	NCV	Failure to Perform Required Parts Evaluation for Control Rod Drive Accumulator Clamps
50-265/02-05-04	FIN	Inadequate Digital Feedwater System Design and Inadvertent Grounding of Plant Equipment Results in Reactor Scram
50-254/02-05-05; 50-265/02-05-05	NCV	Failure to Meet 10 CFR 50.62 due to Relief Valves Lifting

Closed

50-265/02-05-01	NCV	Failure to Participate in Turnover Contributes to Manual Reactor Head Vent Isolation Valves Being Left Open During Unit Startup
50-265/02-05-02	NCV	Failure to Have Unit 2 HPCI System Operable With Reactor Pressure Greater than 150 psig
50-254/02-05-03; 50-265/02-05-03	NCV	Failure to Perform Required Parts Evaluation for Control Rod Drive Accumulator Clamps
50-265/02-05-04	FIN	Inadequate Digital Feedwater System Design and Inadvertent Grounding of Plant Equipment Results in Reactor Scram
50-254/02-05-05; 50-265/02-05-05	NCV	Failure to Meet 10 CFR 50.62 due to Relief Valves Lifting
50-254/00-001-01	LER	Automatic Reactor Scram from Low Reactor Vessel Level
50-254/00-002-01	LER	Inadequate Calibration of Post Accident Torus Temperature Monitors
50-254/01-05-02; 50-265/01-05-02	URI	Methods for Changing Maintenance Rule Performance Criteria
50-254/01-17-02; 50-265/01-17-02	URI	Unexpected Lifting of Standby Liquid Control Relief Valves
50-265/02-001-00	LER	High Pressure Coolant Injection System Uncoupled Above 150 psig due to Misapplication of Technical Specifications
50-254/02-002-00	LER	Manual Scram due to Reactor Vessel Level Transient as a Result of Digital Feedwater Level Control System Design Error

LIST OF ACRONYMS AND INITIALISMS USED

AA	Access Authorization
ALARA	As-Low-As-Is-Reasonably-Achievable
ATWS	Anticipated Transient Without Scram
CFR	Code of Federal Regulations
CR	Condition Report
DOT	Department of Transportation
EPRI	Electric Power Research Institute
HPCI	High Pressure Coolant Injection
LER	Licensee Event Report
mlb/hr	Million Pounds per Hour
MWe	Megawatts Electric
NEI	Nuclear Energy Institute
NRR	Office of Nuclear Reactor Regulation
psig	Pounds per Square Inch Gauge

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

QCOP 0010-10	Required Hot Weather Routines	Revision 3
OP-AA-108-109	Seasonal Readiness	Revision 0
	Summer Readiness Action Matrix	
	Seasonal Readiness Assessment	
	Updated Final Safety Analysis Report	
QCOA 0010-10	Tornado, Thunderstorms and High Winds	
QCOP 3900-01	Service Water System Operation	Revision 6
QCOP 1000-09	Torus Cooling System Startup and Operation	Revision 15
	System Engineering Seasonal Readiness Material Condition List	
	List of Overdue Preventive Maintenance Tasks and Maintenance Items on Service Water and Torus Cooling Systems	

1R04 Equipment Alignment

QCOP 6600-04	Diesel Generator ½ Preparation for Standby Operation	Revision 20
QCOP 1300-1	Reactor Core Isolation Cooling System Preparation for Standby Operation	Revision 20
QCOP 2300-01	High Pressure Coolant Injection System Preparation for Standby Operation	Revision 31

1R05 Fire Protection

	Quad Cities Units 1 and 2 Updated Fire Hazards Analysis	Revision 13
QCAP 1500-1	Administrative Requirements Fire Protection	Revision 14
	Quad Cities Pre-Fire Plans	Revision 11
QCMMS 4100-71	Fire Extinguisher Inspection	Revision 7
QCIS 4100-40	Unit 1 Reactor Building (El. 623 ft.) Fire Protection Functional Test	Revision 1

Work Order 99211567-01	Reactor Building Fire Protection Functional Test	August 28, 2001
Work Order 99247251-01	Perform Fire Extinguisher Annual Inspection of the Reactor Building	December 7, 2001
Condition Report 092971	Station Fire Extinguishers Exceeding their Hydro Due Dates	January 31, 2002
Condition Report 108416	Potential Administrative Error in QCIS 4100-40	May 16, 2002

<u>1R06</u> <u>Flood Protection Measures</u>

QCOA 0010-16	Flood Emergency Procedure	Revision 8
QCAP 0250-06	Control of In-Plant Watertight “Submarine” Doors	Revision 6
	Quad Cities Special Report 3	October 16, 1972
	Quad Cities Special Report 3A	November 7, 1972
	Quad Cities Special Report 3B	April 7, 1973
QCTS 810-01	Reactor Building Internal Flood Barriers Surveillance	Revision 2
QCTS 820-01	Leak Test of the RHR Service Water Vault Flood Protection Penetrations	Revision 7
QCTS 820-02	Leak Test of the RHR Service Water Vault Flood Protection Bulkhead Doors	Revision 6
QCTS 820-03	Leak Test of the RHR Service Water Vault Flood Protection Watertight Doors	Revision 6
QCTS 820-10	RHR Service Water Vault Sump Discharge Check Valve Test	Revision 5
QCMPM 1500-02	RHR Service Water Submarine Door Preventive Maintenance	Revision 5
QCMPM 1500-03	Reactor Building Basement Submarine Door Preventive Maintenance	Revision 5
Condition Report 00094142	Watertight Sub Door Found Open	February 7, 2002
Condition Report 00094747	Admin Procedure Directs Plugging Floor Drains	February 11, 2002
Condition Report 00094761	Unit 2 Condensate Pump Room Approximately 6 Inches of Water on Floor	February 16, 2002

Condition Report 00093609	Plant Tour	February 2, 2002
Condition Report 00093012	Inconsistencies in UFSAR Sec 3.4.1.2.1 RHRSW Vault Flood Protection	January 28, 2002

1R11 Operator Licensing Requalification

Operating Exam Number Three Guide	Main Steam Line Flow Instrument Failure/Large Loss Of Coolant Accident/Reactor Pressure Vessel Flooding	Revision 17
QGA 100	Reactor Pressure Vessel Control	Revision 7
QGA 200	Primary Containment Control	Revision 8
QGA 500-1	Reactor Pressure Vessel Blowdown	Revision 11
EP-AA-111	Emergency Classification and Protective Action Recommendations	Revision 3

1R12 Maintenance Rule Implementation

	Maintenance Rule Data Package for Automatic Depressurization System (Valves and logic)	April 2002
Condition Report 96900	Performance of Automatic Depressurization System Logic Test	February 26, 2002
Condition Report 99577	Unit 2 125 Volt Battery Ground	March 16, 2002
	Maintenance Rule Data Package for Reactor Protection System	April 2002
Condition Report 96885	Full SCRAM from IRM 16	February 26, 2002
Condition Report 97046	Inadvertent ½ SCRAM	February 27, 2002
Condition Report 96900	Received B Channel ½ SCRAM	February 25, 2002
Condition Report 96900	RPS ½ SCRAM from LPRM	February 24, 2002
	Maintenance Rule Data Package for Division II Alternating Current	April 2002

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

	Work Week Safety Profile	Week of April 06, 2002
	Work Week Safety Profile	Week of April 13, 2002
	Work Week Safety Profile	Week of April 27, 2002
	Work Week Safety Profile	Week of May 4, 2002
	Work Week Safety Profile	Week of May 13, 2002
	Work Week Safety Profile	Week of May 20, 2002
	Daily Production Plan Of The Day	Week of April 06, 2002
	Daily Production Plan Of The Day	Week of April 13, 2002
	Daily Production Plan Of The Day	Week of April 27, 2002
	Daily Production Plan Of The Day	Week of May 4, 2002
	Daily Production Plan of The Day	Week of May 13, 2002
	Daily Production Plan of The Day	Week of May 20, 2002
WC-AA-103	On-Line Maintenance	Revision 4

1R14 Personnel Performance During Nonroutine Plant Evolutions

Condition Report 101320	HPCI Uncoupled with Reactor Pressure Greater than 150 psig	March 28, 2002
Prompt Investigation Report for Condition Report 101320	Unit 2 HPCI Turbine was Left Uncoupled and Reactor Pressure was Raised Above 150 psig	March 28, 2002

Root Cause Investigation Report for Condition Report 101320	High Pressure Coolant Injection System was not Operable when Required due to Operations Misunderstanding and Misapplication of Technical Specifications	April 25, 2002
Condition Report 97694	Unit 2 Reactor Head Vent Bypass Valves Found Open	March 4, 2002
Condition Report 110590	Readdress Apparent Cause Evaluation for Condition Report 91694	June 4, 2002
Condition Report 112360	NRC Identifies Issue With Apparent Cause/Corrective Actions for Manual Head Vents	June 19, 2002
OP-AA-112-101	Shift Turnover and Relief	Revision 0
HU-AA-104-101	Procedure Use and Adherence	Revision 0
OP-AA-108-102	Equipment Status Tags	Revision 0
QCOS 0201-08	Reactor Vessel and Class One Piping Leak Test	Revision 27
Condition Report 111065	Reactor Pressure Made a Step Drop from 1002# to 999#	June 7, 2002
	Available Unit 2 Plant Data	June 7, 2002
	Unit 2 Reactor Operator Logs	June 7-9, June 18, and June 20, 2002
Condition Report 111976	Unexpected Change in Unit 2 Parameters	June 17, 2002
Operability Evaluation for Condition Report 111976	Unit 2 Steam Dryer Problems	June 19, 2002
Condition Report 112294	Level, Pressure, and MWe Transient	June 18, 2002
	Unit 2 Reactor Operator Logs and Plant Data	June 18, 2002

1R15 Operability Evaluations

Action Request 98960-08	1A RHR Heat Exchanger Operability Documentation	March 13, 2002
Condition Report 102235	Gland Seal Water to Unit 1 EDG	April 3, 2002

Problem Identification Form Q1998-01025	Operability Determination for work on U1 EDG	March 20, 1998
Quad Cities Data Request Form 3086	EDG Cooling Water Pump Seals	August 26, 1993
Condition Report 98263	Hydraulic Control Units Restraining Band Clamps	March 7, 2002
Engineering Evaluation	Control Rod Drive Accumulator Missing Strap Evaluation	April 2, 2002
Condition Report 105454	General Electric Part 21 Notification SC 02-05	April 26, 2002
Condition Report 107669	Ineffective Corrective Action for NON DR-01-060	Unknown
Operability Evaluation for Condition Report 105454	General Electric CR105X Auxiliary Contacts	May 10, 2002
10 CFR Part 21 Notification	Failure of CR105X Auxiliary Contacts	April 23, 2002
General Electric Service Advisory Letter 2.1	CR105X Auxiliary Interlock Malfunction - Nuclear Power Stations	August 2, 1978
Dresden Station Operability Evaluation 02-004	General Electric CR105X Auxiliary Contacts on Size 1 Contactors	February 8, 2002
Operability Evaluation for Condition Report 111976-09	Moisture Carryover Preliminary Analysis - Quad Cities Unit 2	June 18, 2002

1R19 Post-Maintenance Testing

Work Order 00395688	U2 #3 Power Operated Relief Valve Replacement	February 12, 2002
	Quality Receipt Inspection Package for Power Operated Relief Valve	December 21, 2001
Work Order 00423819	U2 #3 Power Operated Relief Valve Replacement	March 29, 2002

QCOS 0010-08	High Radiation Area Inspection Guidelines	Revision 2
QCOS 0201-12	Class One ASME Section XI Post Replacement Pressure Test At Power Operation	Revision 2
QCOS 0005-04	IST Valve Position Indication Surveillance	Revision 8
QCOS 1600-31	Suppression Pool Water Temperature Monitoring	Revision 4
QCOS 0203-03	Main Steam Relief Valves Operability Test	Revision 18
Work Order 00379753	½ Diesel Generator Lube Oil Circulating Pump	March 27, 2002
Work Order 00363309	½ Diesel Generator Local Tachometer	March 20, 2002
Work Order 00395531	½ Diesel Generator Starting Air Strainer	March 19, 2002
Work Order 00418906	½ Diesel Generator Timing Relays	March 20, 2002
QCOS 6600-43	Unit ½ Diesel Generator Load Test	Revision 9
Work Order 9927921801	Replace 125 VDC Breaker for HPCI Logic System Control Power	February 24, 2002
Work Order 0041049301	U1 HPCI Steam Chest Hold Down Bolts	March 27, 2002
Work Order 9915729901	1-2301-22 16" Gate Valve Overhaul	March 27, 2002
Work Order 9926231301	HPCI Flow Controller FIC 1-2340-01 Dynamic calibration	March 19, 2002
QCOS 2300-05	Quarterly HPCI Pump Operability Test	Revision 44
Work Order 00452432-07	U1 Repair Pinhole Leak on Pump Discharge Piping - 1B RHRSW	June 13, 2002
QCOS 1000-04	RHR Service Water Pump Operability Test	Revision 30

1R22 Surveillance Testing

QCIS 0700-22	Unit 1 Division II Power Operation APRM Functional Test	Revision 0
QCOS 1400-08	Core Spray System Power Operated Valve Test	Revision 14

QCOS 6600-41	Unit 1 Diesel Generator Load Test	Revision 10
QCOS 6600-42	Unit 2 Diesel Generator Load Test	Revision 10
QCOS 6600-03	Diesel Fuel Oil Transfer Pump Monthly Operability	Revision 14
QCOS 6600-02	Diesel Generator Air Compressor Operability	Revision 15
QCOS 0203-07	Automatic Blowdown Logic Test	Revision 5
CY-QC-120-600	Off-Gas Sampling	Revision 3
CY-QC-130-401	Off-Gas Isotopic Analyses Recombiner Outlet and Adsorber Inlet Samples	Revision 1
QCOS 1600-45	Unit 2 Primary Containment Isolation Group 3 Test	Revision 2
QCOS-1000-06	Residual Heat Removal/LOOP Operability Test	Revision 28

1R23 Temporary Plant Modifications

Work Order 414436	Install Steel Cap on 2-0220-57A Valve	April 29, 2002
Engineering Change 336058	ASME Section XI Code Reconciliation	April 29, 2002
Design Analysis 02-007	Stress Report for Valve 2-0220-57A and Cover	April 29, 2002
Design Analysis Q2-FW-02C/Analysis	Evaluation of Temporary Modification of Valve 2-0220-57A	April 28, 2002

1EP4 Emergency Action Level and Emergency Plan Changes

	Quad Cities Nuclear Power Station Annex to the Exelon Nuclear Standardized Radiological Emergency Plan	Revision 14

1EP6 Drill Evaluation

LOCT-1002 EPU	Loss of Coolant Accident/Loss of Normal Feedwater	Revision 0
QGA 100	Reactor Pressure Vessel Control	Revision 7
QGA 200	Primary Containment Control	Revision 8
QGA 300	Secondary Containment Control	Revision 11

EP-AA-111	Emergency Classification and Protective Action Recommendations	Revision 3
	Scenario for April 19, 2002, Emergency Preparedness Drill	
	Nuclear Accident Reporting System and Emergency Notification System Forms from April 19, 2002 Emergency Preparedness Drill	April 19, 2002
	Scenario for June 12, 2002, Emergency Preparedness Pre-Exercise	
	Nuclear Accident Reporting System and Emergency Notification System Forms from June 12, 2002 Emergency Preparedness Pre-Exercise	June 12, 2002
NEI 99-02, Revision 2	Regulatory Assessment Performance Indicator Guideline	November 2001

2OS1 Access Control

LS-AA-125	Corrective Action Program (CAP) Procedure	Revision 2
QCFHP 0500-01	Spent Fuel Storage Pool Inventory Control and Audit	Revision 4
	Nuclear Oversight: NOA-QC-01-4Q	January 30, 2002
	Focus Area Self-Assessment: ALARA Planning and Controls	January 14-21, 2002
55511-35	N.O. Field Observation: Observed Work in Progress	August 7, 2001
55511-34	N.O. Field Observation: Observed Work in Progress	August 12, 2001
55511-55	N.O. Field Observation: Observed Work in Progress	August 31, 2001
55511-43	N.O. Field Observation: Observed Work in Progress	September 18, 2001
55511-41	N.O. Field Observation: Work Practices	September 20, 2001
55511-54	N.O. Field Observation: ALARA Program	September 24, 2001
88678-08	N.O. Field Observation: Radiation Postings, Labeling and Calibration	January 4, 2002

88678-09	N.O. Field Observation: Radiation Postings, Labeling and Calibration	January 9, 2002
88678-11	N.O. Field Observation: U1 Drywell Access Control Point	January 19, 2002
88678-36	N.O. Field Observation: Radiation Postings, Labeling and Calibration	February 13, 2002
88678-52	N.O. Field Observation: Dosimetry Placement	February 27, 2002
88678-27	N.O. Field Observation: U2 Drywell Access Control Point	February 27, 2002
88678-46	N.O. Field Observation: Radiation Postings After U2 Start Up	March 6, 2002
88678-50	N.O. Field Observation: RP Programs-Internal Dose Control	March 14, 2002
88678-56	N.O. Field Observation: Source Term Reduction	March 27, 2002
97378	Increased Dose Rates in Reactor Cavity Post Drain Down	March 1, 2002
95481	Higher Than Expected Dose Rates Identified in the D Heater Bay	February 15, 2002
96664	IDNS Inspector Identifies Radworker Issues	February 21, 2002
97884	Grit Blasting Turbine Component Without RP Coverage	March 5, 2002
98886	Offgas Leak Outside of the 2A Recombiner	March 12, 2002
95715	Personnel Contamination Event	February 17, 2002
96430	Poor Radworker Practice at CRD Repair Room	February 23, 2002
97547	Refuel Floor Worker Contaminated	March 2, 2002
97871	Packing Leak: Unplanned Spread of Contamination	March 5, 2002
95707	Steam Dryer Underwater Brushing Increases Contact Dose Rates	February 19, 2002
95523	Unplanned Spread of Contamination U2 Torus Area	February 16, 2002
98823	Unplanned Spread of Contamination	March 12, 2002
98930	U2 RWCU Valve Room Elevated Dose Rates	March 13, 2002

94259	Unplanned Spread of Contamination	February 7, 2002
100363	Unplanned Spread of Contamination Outside of the 1A CS Room	March 21, 2002
100312	Unplanned Spread of Contamination U2 RB 623	March 21, 2002
101745	Unplanned Spread of Contamination U2 623	March 31, 2002
102737	RP Shielding Questions for Equipment After LCO Started	April 8, 2002
100374	NOS Identified Problems With Documentation for Contamination Events	January 11, 2002
98258	NOS Identified Survey Not Revised For Dosimetry Placement	February 27, 2002

<u>2OS2 ALARA Planning and Controls</u>

RP-AA-400	ALARA Program	Revision 2
RP-AA-401	Operational ALARA Planning and Controls	Revision 2
WC-AA-101-1002	On Line Scheduling Process	Revision 0
RP-AA-270	Prenatal and Postnatal Programs	Revision 1
10001166	RWP/ALARA Plan: 1B Recirc Pump Motor, Remove/Replace Motor and Interferences (Q1F49)	January 19, 2002
10001154	RWP/ALARA Plan: 1B Recirc Pump, Removal/Install Pump Internals (Q1F49)	January 20, 2002
10001135	RWP/ALARA Plan: U1 Reactor Disassembly/Reassembly, Cavity Work and Wall Cleaning (Q1F49)	January 10, 2002
10000326	RWP/ALARA Plan: U2 EPU Mod, Uprate of RFW Heater Shells/Nozzles (Q2R16)	December 19, 2001
10000220	RWP/ALARA Plan: U2 Drywell Shielding Activities (Q2R16)	December 19, 2001
10000233	RWP/ALARA Plan: U2 CRDs (24), Unlatch/Remove/Replace (Q2R16)	January 19, 2002
	Source Term Reduction Plan (Draft)	2002

<u>2PS2 Transportation of Radioactive Materials</u>

	Uniform Low-Level Radioactive Waste Manifest	April 9, 2002

3PP Physical Protection

SY-AA-101-112	Searching Personnel and Packages	Revision 5
SY-AA-101-122	Testing Security Equipment	Revision 5
SY-AA-101-123	Searching Vehicles and Cargo/Material	Revision 6
SY-AA-101-120	Control of Security Keys and Cores	Revision 1
SY-AA-102	Exelon's Nuclear Fitness for Duty Program	Revision 5
SY-AA-103-511	Request for Unescorted Access	Revision 7
SY-AA-103-512	Continual Behavioral Observation Program	Revision 3
SY-AA-103-514	Fabrication of Security Badges	Revision 6
TQ-AA-118	Nuclear General Employee Training - N-GET	Revision 3
Security 3rd Quarter 2001 Focus Area Self-Assessment Report	Security Equipment Testing (AR# 43391-03, Security Training Program	July - September 2001
	Security Event Logs	October 2000 - September 2001
	Security Incident Reports	July 2001 - March 2002
	Security Work Requests	July 2001 - March 2002
Nuclear Oversight Continuous Assessment Report NOA-QC-01-4Q	Security Assessment	October - December 2001
Security Focus Area Self-Assessment Report	Vehicle Search	April 2 - June 30, 2001
Security Focus Area Self-Assessment Report	Security Ingress/ Access Control	October - December 2001

Security Focus Area Self-Assessment Report	NRC Audit Preparation - Access Authorization, Access Control, Security Plan Changes, and Performance Indicator Data	October 2001 - January 2002
Security Focus Area Self-Assessment Report	Safeguards Controls	February 12-28, 2002

4OA1 Performance Indicator Verification

	Unit 1 Operator Logs	July 2001 - March 2002
	Unit 2 Operator Logs	July 2001 - March 2002
LS-AA-2010	Monthly Performance Indicator Data Elements for Unplanned SCRAMS for 7000 Critical Hours	July 2001 - March 2002
LS-AA-2020	Monthly Performance Indicator Data Elements for SCRAMS with a Loss of Normal Heat Removal	July 2001 - March 2002
	Quad Cities Monthly Operating Reports	July 2001 - May 2002
LS-AA-2030	Monthly Performance Indicator Data Elements for Unplanned Power Changes per 7000 Critical Hours	July 2001 - May 2002
	NRC Inspection Reports	July 2001 - March 2002

4OA2 Identification and Resolution of Problems

Condition Report 79779	Incorrect Injectors Installed During QCMMS 6620-05	October 2, 2001
Condition Report 89176	Unplanned Technical Specification Limiting Condition for Operation Entry	January 7, 2002
Condition Report 89499	Mechanics Start to Breach Wrong Valve	January 7, 2002
Condition Report 89830	Chemistry Department Event Free Clock Resets	January 10, 2002
Condition Report 90267	Plastic Protractor Missing Off Ultrasonic Testing Fixture in Vessel	January 13, 2002

Condition Report 91162	Incorrect Jet Pump Beam Detensioned due to Identification Error	January 17, 2002
Condition Report 91235	1A Recirculation Pump Motor Bearing Oil Inadvertently Changed	January 18, 2002
Condition Report 92250	2B Control Rod Drive Pump Catastrophic Failure	January 24, 2002
Condition Report 92430	Station Human Performance Issues in January 2002	January 25, 2002
Condition Report 92943	Normally Closed Valve Found Throttled Open and Damaged	January 29, 2002
Condition Report 94142	Watertight Submarine Door Found Open	February 7, 2002
Condition Report 94249	1B Reactor Recirculation Pump Trip	February 7, 2002
Condition Report 95097	Safety Relief Valves 4B and 4E Rams Heads Installed in the Incorrect Position	February 14, 2002
Condition Report 95152	1A Offgas Hydrogen Analyzer Exceeded Surveillance Frequency	February 13, 2002
Condition Report 95467	Working on System Without Clearance Order	February 15, 2002
Condition Report 95532	Removed Limitorque from 2-220-2 with Out of Service Card on Handwheel	February 17, 2002
Condition Report 95542	Hydrogen Deflagration in Condensate System During Welding	February 17, 2002
Condition Report 96155	Unit 1 D Heaters Tripped at Full Power	February 25, 2002
Condition Report 96875	Near Miss While Filling Main Condenser	February 26, 2002
Condition Report 96890	Unexpected Auto Start of 2A Core Spray Pump	February 26, 2002
Condition Report 97694	Unit 2 Reactor Head Vent Bypass Valves Found Open	March 4, 2002
Condition Report 98256	2B Condensate Pump Outboard Seal Failure due to Foreign Material	March 7, 2002
Condition Report 99953	Plugs Installed on Unit 2 Feedwater Heaters C and D Relief Valve Vents	February 25, 2002

Condition Report 100473	Incorrect Availability Call for Unit 1 HPCI Turning Gear Logic Test	March 21, 2002
Condition Report 101320	Unit 2 HPCI Turbine was left Uncoupled and Reactor Pressure was Raised Above 150 psig	March 28, 2002
Condition Report 102589	Manual Reactor Scram on Increasing Reactor Pressure Vessel Level due to Inadequate Original Design of the Digital Feedwater System	April 5, 2002
Condition Report 107804	Unit 2 Valves Operated During Unit 1 Residual Heat Removal Timing Surveillance	May 13, 2002
Condition Report 108873	Incorrect Transformer Cooling Fan Identified for Maintenance	April 22, 2002
Condition Report 111114	Transformer T2 Deluge was Activated During Fire Protection Surveillance	June 8, 2002

4OA3 Event Followup

QCOA 0201-08	Reactor High Water Level	Revision 14
QCGP 2-3	Reactor SCRAM	Revision 40
QGA 100	RPV Control	Revision 7
Condition Report 102589	Prompt Investigation of Unit 2 SCRAM	April 5, 2002
Licensee Event Report 50-254/00-001	Automatic Reactor Scram from Low Reactor Vessel Level	Revision 1
Licensee Event Report 50-254/00-002	Inadequate Calibration of Post Accident Torus Temperature Monitors	Revision 1
Licensee Event Report 50-265/02-001	High Pressure Coolant Injection System Uncoupled Above 150 psig due to Misapplication of Technical Specifications	Revision 0
Licensee Event Report 50-265/02-002	Manual Scram due to Reactor Vessel Level Transient as a Result of a Digital Feedwater Level Control System Design Error	Revision 0

4OA5 Other

Task Interface Agreement 2001-07	Response to Task Interface Agreement 2001-07 From Region III Regarding Quad Cities Maintenance Rule Issues	May 1, 2002

Task Interface Agreement 2001-12	Response to Task Interface Agreement 2001-12 Regarding Susquehanna Steam Electric Plant, Units 1 and 2, Design and Licensing Basis for the Standby Liquid Control System	May 6, 2002