January 27, 2003

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
Quad Cities Nuclear Power Station
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 50-254/02-08; 50-265/02-08

Dear Mr. Skolds:

On December 28, 2002, the U. S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. The enclosed report documents the inspection findings which were discussed on December 31, 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 seven issues of very low safety significance (Green). Three of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of a Non-Cited Violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulation Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region III, 801 Warrenville Road, Lisle, IL 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Quad Cities Nuclear Power Station.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. Phase 1 of TI 2515/148 was completed at all commercial nuclear power reactors during calendar year (CY) ‘02, and the remaining inspections are scheduled for completion in CY ‘03. Additionally, table-top security drills were conducted at several licensees to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY ‘03, the NRC will continue to monitor overall safeguards and security controls and conduct inspections, and will resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial nuclear power reactors.

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 50-254/02-08; 50-265/02-08

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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:	50-254/02-08; 50-265/02-08
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	October 1 through December 28, 2002
Inspectors:	K. Stoedter, Senior Resident Inspector M. Kurth, Resident Inspector J. House, Radiation Protection Inspector D. Jones, Engineering Inspector R. Kopriva, Senior Project Engineer, Region IV P. Lougheed, Engineering Inspector D. Nelson, Radiation Protection Inspector P. Pelke, Reactor Engineer G. Pirtle, Physical Security Inspector T. Ploski, Senior Emergency Preparedness Inspector S. Sheldon, Engineering Inspector T. Steadham, Reactor Engineer
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000254/2002-008, 05000265/2002-008; Exelon Nuclear; on 10/01-12/28/02, Quad Cities Nuclear Power Station; Units 1 & 2. Adverse Weather, Refueling and Outage Activities, Identification and Resolution of Problems, and Event Followup.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on Temporary Instruction 2515/148, radiation protection, inservice inspection, and emergency preparedness. The inspection was conducted by regional inspectors and the resident inspectors. Three Severity Level IV Non-Cited Violations (NCV) and seven Green Findings were identified. 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 may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Initiating Events

Green. The failure to identify the proper plant air supply prior to installing moisture separator decontamination equipment (air powered vacuum) resulted in two unexpected instrument air system transients on October 14 and 15, 2002. The work package did not contain equipment identification numbers to aid in identifying the proper air supply. In addition, the individual instructed to identify the air supply failed to perform self-checking activities that could have identified the inappropriate selection of instrument air for the equipment installation rather than service air.

This finding was more than minor because it affected the loss of instrument air initiating event frequency. The finding was of very low safety significance because the exposure time was short and all mitigating systems needed to address a loss of instrument air were available. No violation of NRC requirements occurred due to the instrument air system being non-safety-related. (Section 1R20.1)

Green. The failure to adequately correct deficiencies in the 1B reactor recirculation motor generator voltage regulator resulted in a pump trip and power transient on December 6, 2002. On November 29 and December 3, the licensee initiated two condition reports due to the motor generator voltage regulator failing to meet acceptance criteria during tuning activities. The inspectors determined that the licensee had not adequately considered changes made to the voltage regulator during the outage and power ascension which resulted in inappropriately concluding that the failure to meet the acceptance criteria was acceptable.

This finding was determined to be more than minor because the reactor recirculation pump trip was a precursor to a significant transient. This finding was considered to be of very low safety significance since it did not: contribute to the likelihood of both a reactor trip and that mitigating equipment would not be available, contribute to the likelihood of a loss of coolant accident, increase the likelihood of a fire or flood, or increase the frequency of core damage scenarios using other plant specific analyses. (Section 4OA2.1)

Cornerstone: Mitigating Systems

Green. A self-revealing failure occurred on October 16, 2002, when the safe shutdown makeup pump room cooler strainer became clogged with duck weed. The inspectors determined that twice per shift rounds to verify strainer operability and multiple strainer cleanings were not effective in ensuring continued operability of this equipment. In addition, control room personnel were not immediately notified of the clogged strainer via a control room alarm or a local alarm due to a system design deficiency.

This finding was more than minor because the strainer clogging impacted the operability of the safe shutdown makeup pump which can be used when responding to initiating events. In addition, the system design issues created a situation where operations personnel were unaware of equipment operability issues. This finding was of very low safety significance because the total exposure time was short, all other mitigating systems were available, and the safe shutdown makeup pump could have been recovered if needed. No violation of NRC requirements occurred due to the safe shutdown makeup only being of augmented quality per the licensee's Quality Assurance Report. (Section 1R01.2)

Green. During the 1A stator water heat exchanger tube bundle replacement on November 11, 2002, approximately 200 gallons of water were released as the tube bundle was pulled from the heat exchanger. The water migrated to the Unit 1 emergency diesel generator room below and tripped the circulating oil pump and turbocharger lubricating oil pump rendering the diesel inoperable. The work package used to perform the work did not contain information regarding the large amounts of water that may be present in the heat exchanger. In addition, information regarding the amount of water present in the heat exchanger was not communicated to the contractors performing the work even though this information was well known by operations and maintenance personnel.

This finding was more than minor because the inadequate work instructions and poor communications resulted in a situation which impacted the operability, availability, and reliability of the emergency diesel generator. The finding was of very low safety significance since the loss of the emergency diesel generator did not result in an actual loss of safety function of a system and did not result in an actual loss of safety function of a single train for greater than the Technical Specification Allowed Outage Time. No violations of NRC requirements were identified due to the stator water heat exchanger being non-safety-related. (Section 1R20.2)

Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion V, due to the failure to adhere to procedural requirements regarding the erection of scaffolding near safety-related equipment. On November 6, 2002, the inspectors identified numerous examples where scaffolding was in contact with residual heat removal system piping and valves.

This finding was more than minor since multiple examples of scaffolding erection deficiencies were identified which indicated that workers routinely failed to follow scaffolding erection procedural requirements. This finding was determined to be of very low safety significance since the scaffolding did not result in an actual loss of safety function of any system. (Section 1R20.4)

Green. A loose wire caused a condition that would have resulted in the failure of the 2B residual heat removal system to automatically start when required and would have resulted in the diversion of water from the 2A residual heat removal system if an emergency core cooling system actuation signal was received while the 2B residual heat removal system was operating in torus cooling. One Non-Cited Violation of Technical Specification 3.5.1 was identified. The licensee determined that the wire was loosened during the February 2002 refueling outage. The impact of the loose wire was not addressed until October 2002 even though unexpected equipment performance was experienced on three previous occasions.

This finding was more than minor since the loose wire impacted the operability, availability, reliability, and capability of the residual heat removal system. The finding was determined to be of very low risk significance since the both trains of the residual heat removal system were recoverable using simple operator actions and all remaining mitigating systems equipment were available. (Section 4OA3.2)

Cornerstone: Barrier Integrity

Green. The failure to adhere to procedure precautions and perform timely control room panel monitoring resulted in the inadvertent isolation of the reactor water cleanup system while the system was being used to remove decay heat from the Unit 1 reactor vessel. A Non-Cited Violation of Technical Specification 5.4.1 was identified.

This finding was determined to be more than minor because the isolation impacted the reactor water cleanup system's continued ability to provide cooling of the reactor fuel and fuel cladding while the Unit 1 reactor was in a shutdown condition. The finding was of very low safety significance since the isolation did not significantly degrade the licensee's ability to recover decay heat removal through the use of the reactor water cleanup or residual heat removal systems once the isolation occurred. (Section 1R20.3)

B. Licensee-Identified Violations

Licensee-Identified Violations of very low safety significance have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the 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 operating at reduced power levels due to entering coastdown. On November 5 operations personnel shut down Unit 1 and began a refueling outage. Major activities accomplished during the outage included implementation of an extended power uprate, replacement of the high pressure turbine rotor, modifications to the reactor steam dryer, installation of new condensate demineralizers, and upgrading the high and low pressure feedwater heaters. Unit 1 achieved criticality on November 25 and was synchronized the grid the following day. On December 2 the licensee began power uprate testing. During the multi-day testing evolution, an unisolable leak developed on the 1B reactor feedwater pump. Operations personnel lowered reactor power to 85 percent to complete the leak repairs. On December 6 the operators restored reactor power to 94 percent and began additional power uprate testing. Upon reaching 97 percent power, the 1B reactor recirculation pump tripped due to motor generator set overcurrent on two out of three phases. The pump trip resulted in reducing reactor power to approximately 35 percent. The licensee completed repairs to the reactor recirculation pump on December 9 and continued with the power ascension. Unit 1 achieved and maintained the maximum post-extended power uprate power level on December 11. Engineering and operations personnel completed all required power uprate testing later the same week.

Unit 2 entered the inspection period operating at the maximum achievable power level. On October 7 operations personnel lowered reactor power to approximately 80 percent to repair a leak on the 2A reactor feedwater pump suction relief valve. Unit 2 returned to its maximum power level on October 9. On November 8 and December 5, operations personnel lowered reactor power to approximately 85 percent to conduct turbine valve testing. In both cases the unit was returned to maximum power levels within 24 hours.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Routine Cold Weather Preparations

a. Inspection Scope

From October 29 through November 1, 2002, the inspectors assessed the station's readiness for cold weather conditions by conducting detailed inspections on the ice melt valve and the heat tracing system. The inspectors chose the ice melt valve for inspection due to its importance in preventing the freezing of water for the service water, circulating water, fire water, residual heat removal service water and emergency diesel generator service water systems. The heat tracing system was chosen because of its importance in maintaining the operability of safety-related piping exposed to extreme temperature conditions. The inspectors reviewed the Updated Safety Analysis Report, and seasonal readiness and adverse weather procedures to determine the operational requirements of the ice melt valve and heat tracing systems during cold weather conditions. The inspectors compared this information to the licensee's seasonal readiness open items list, system readiness reports, and open maintenance work requests to ensure that none of the items on these lists impacted the ability of the ice melt valve and heat tracing system to perform their intended functions. The inspectors performed a review of previously initiated condition reports related to cold weather conditions and performed a plant walkdown to ensure that the items documented in the condition reports had been appropriately corrected.

b. Findings

No findings of significance were identified.

.2 Review of Site Specific Weather Condition

a. Inspection Scope

On October 16, 2002, the safe shutdown makeup pump experienced a self-revealing failure when the room cooler service water strainer became fouled with duck weed. The safe shutdown makeup pump system is one of three high pressure systems that can be used to inject water into the reactor during accident conditions. The safe shutdown makeup pump is classified as a risk significant system under the Maintenance Rule and is credited as an injection source in the Appendix R (Fire Protection) Safe Shutdown Analysis. Between October 16 and November 5, 2002, the inspectors performed an in-office review of Condition Report 127679, the apparent cause evaluation, operations logs, and procedures associated with the safe shutdown makeup pump to determine past system performance and the reason for the failure. The inspectors interviewed operations, maintenance, and engineering personnel to assess the service water strainer clogging frequency during increased river debris conditions. The inspectors also conducted an inspection of the safe shutdown makeup pump room, including the room cooler and service water systems, to monitor room cooler performance.

b. Findings

The inspectors identified one Green finding due to an inadequate system design which prevented operations personnel from immediately discovering that the safe shutdown makeup pump room cooler service water strainer was clogged with duck weed.

Under normal conditions, operations personnel conducted periodic checks of the safe shutdown makeup pump room cooler service water duplex strainer. When the duplex strainer's differential pressure reached 10 psid or greater, operations personnel were required to swap duplex strainers and notify maintenance to clean the fouled strainer. During increased river debris conditions, operations personnel were required to check the duplex strainer differential pressure twice per shift.

On October 16, 2002, an operator entered the safe shutdown makeup pump room, noticed that the room seemed warmer than normal, and that the room cooler was not in operation. Since the room cooler was needed to support continued operability of the safe shutdown makeup pump, control room personnel entered Technical Specification 3.7.9. Troubleshooting determined that the safe shutdown makeup pump room cooler was not operating due to the both sides of the service water duplex strainer being fouled.

The inspectors questioned various personnel to determine why operations was not immediately notified of the safe shutdown makeup pump room cooler malfunction via a local or control room alarm. The inspectors were informed that the safe shutdown makeup pump room cooler circuitry was designed without any local or control room alarm functions which could be used to notify personnel of equipment malfunctions. Due to this inadequate design, operations personnel were relying on operator rounds to ensure continued operability of the safe shutdown makeup pump and its associated support equipment.

The inspectors determined that the failure to ensure the safe shutdown makeup pump room cooler circuitry was adequately designed to warn personnel of equipment malfunctions was more than minor because it: (1) involved the design control and protection against external factors attributes of the mitigating systems cornerstone; and (2) affected the cornerstone objective of ensuring the operability, availability, reliability, and function of a system that responded to initiating events to prevent undesirable consequences.

The inspectors also determined that this finding should be evaluated using the significance determination process described in Inspection Manual Chapter 0609, "Significance Determination Process." The inspectors conducted a Phase 1 screening and determined that a Phase 2 evaluation was required since the strainer clogging and design inadequacy resulted in an actual loss of safety function of a system.

The inspectors used the risk-informed inspection notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 1, dated May 2, 2002, to complete the Phase 2 evaluation. The inspectors determined that the exposure time was less than 3 days since approximately 1.5 hours elapsed between the time the room cooler was last verified to be operable and the time the operator discovered the abnormally warm room. For each significance determination process worksheet completed, the inspectors assumed that all mitigating capability was available except for the safe shutdown makeup pump. The inspectors allowed credit for recovery since the duplex strainer could have been cleaned, and the room cooler re-started, using manual actions. Using these assumptions the inspectors evaluated 22 core damage sequences. Worksheet results ranged from 8 to 18 points. The most dominant core damage sequences involved: (1) the loss of instrument air with the residual heat removal system available for containment heat removal; (2) a transient with the loss of the power conversion system and the automatic depressurization system available; and (3) a loss of service water with the residual heat removal system available for containment heat removal. The inspectors concluded that the final significance determination process result for this finding was 8 points; therefore, this finding was considered to be of very low risk significance (Green) **(FIN 50-254/02-08-01; 50-265/02-08-01)**. The inadequate design issue did not constitute a violation of NRC requirements since the licensee's quality assurance program considered the safe shutdown makeup pump and its associated support equipment to be of augmented quality. This issue was entered into the licensee's corrective action program as Condition Report 127679.

1R05 Fire Protection (71111.05)

a. Inspection Scope

During the inspection period, the inspectors conducted in-plant walkdowns of the following risk-significant fire zones to identify any fire protection degradations:

- Fire Zone 8.2.3.A, Unit 1 Turbine Building Control Rod Drive Pumps;
- Fire Zone 8.2.6.A, Unit 1 Turbine Building Hallway;
- Fire Zone 1.1.1.6, Unit ½ Reactor Building Refuel Floor;
- Fire Zone 8.2.6.B, Unit 1 Turbine Building Low Pressure Heater Bay;
- Fire Zone 11.3.3, Unit 2 Reactor Building Northwest Corner Room, Core Spray;
- Fire Zone 11.3.2, Unit 2 Reactor Building Southeast Corner Room, 2B Residual Heat Removal Room; and
- Fire Zone 11.3.4, Unit 2 Reactor Building Northeast Corner Room, 2A Residual Heat Removal Room.

During the walkdowns the inspectors verified that transient combustibles were controlled in accordance with the licensee's procedures. 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 location of fire extinguishers, hoses, and telephones against the Pre-Fire Plan 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.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors conducted a review of the licensee's inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. Specifically, the inspectors conducted a record review of the following examinations:

WELD #	SYSTEM	NDE TYPE
23S-S9	High Pressure Coolant Injection	Ultrasonic Testing
23S-F4	High Pressure Coolant Injection	Ultrasonic Testing
30C-F27	Main Steam	Ultrasonic Testing
10BD-S8	Residual Heat Removal	Ultrasonic Testing
CRDH Pipe-Pipe	Reactor Pressure Vessel	Penetrant Testing

FW-1	High Pressure Coolant Injection Turbine	Radiographic Testing

These examinations were evaluated for compliance with the American Society of Mechanical Engineers Boiler and Pressure Vessel Code requirements. The inspectors also reviewed inservice inspection procedures, equipment certifications, personnel certifications, and NIS-2 forms for Code repairs performed during the last outage to confirm that American Society of Mechanical Engineers Code requirements were met.

A sample of inservice inspection related problems documented in the licensee's corrective action program, was also reviewed to assess conformance with 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In addition, the inspectors determined that operating experience was correctly assessed for applicability by the inservice inspection group.

b. Findings

The licensee discovered that they had missed inspections of the control rod drive housing welds (Action Report 00113995). Further discussions of this issue with NRC staff was documented in Action Report 00132057. This issue will be an Unresolved Item pending further review of the American Society of Mechanical Engineers Code requirements **(URI 50-254/02-08-02; 50-265/02-08-02)**.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On October 9, 2002, the inspectors observed an operations crew during a requalification examination on the simulator using Scenario 00-28, "Torus Narrow Range Instrument Failure, Loss of Coolant Accident Inside Containment, and an Anticipated Transient Without Scram," Revision 10.

The inspectors evaluated crew performance in the areas of:

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

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

- OP-AA-101-111, "Rules and Responsibilities of On-Shift Personnel," Revision 0;
- OP-AA-103-102, "Watchstanding Practices," Revision 0;
- OP-AA-103-103, "Operation of Plant Equipment," Revision 0;
- OP-AA-103-104, "Reactivity Management Controls," Revision 0; and

- OP-AA-104-101, “Communications,” Revision 0.

The inspectors verified that the crew completed the critical tasks listed in the above scenario. The inspectors also attended meetings with the licensee’s evaluators to ensure that weaknesses noted by the inspectors were noticed by the evaluators and discussed with the crew.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

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

Maintenance Activity Assessed	**Week Inspected**
125 Volt DC Charger Load Testing	December 9, 2002
Risk Associated with U1 High Pressure Coolant Injection Out of Service Due to Emergent Work	December 9, 2002
U2 Core Spray Semiannual Logic Test	December 9, 2002

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions (71111.14)

a. Inspection Scope

On October 7, 2002, the inspectors observed control room activities associated with a Unit 2 power reduction to repair a steam leak on a reactor feedwater pump. The inspectors determined by direct observation and a review of procedural requirements that reactivity manipulations were verified by a second licensed operator, that operations personnel were complying with procedures and Technical Specifications, and that plant parameters were as expected for each operating condition.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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

- Operability Evaluation for Condition Report 124350, “Certain General Electric 480 Volt Breakers not Properly Modeled in ELMS-DC Database,” dated September 24, 2002;

- Discussions Regarding a Lack of Inservice Inspections on Control Rod Drive Housing Welds During October and November 2002 (see Condition Report 132057); and

- Operability Evaluation for Condition Report 131936, “Potential Failure of Belleville Springs in Main Steam Isolation Valves 2-0203-2B and 2-0203-2C,” dated November 20, 2002.

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

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

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16)

Semi-Annual Review

a. Inspection Scope

The inspectors performed a semi-annual review of all operator workarounds and challenges identified as of October 10, 2002. The inspectors assessed the cumulative effects of the workarounds and challenges by performing the following:

- The inspectors compared workaround and challenge information to the normal, abnormal, and emergency operating procedures to ensure that operations personnel maintained the ability to correctly respond to plant transients in a timely manner;

- The inspectors utilized system knowledge, a review of plant procedures, and interviews with operations personnel to ensure that the workarounds and challenges previously identified did not adversely impact system reliability and availability, create the potential for system misoperation, or result in a workaround that impacted multiple mitigating equipment; and

- The inspectors reviewed the equipment status tag log, degraded equipment log, temporary configuration change report, and open operability determination report for potential operator workarounds and challenges that had not been previously identified or assessed for potential impact on normal plant operation or transient response.

In addition to the above, the inspectors reviewed selected issues that the licensee entered into its corrective action program to verify that identified problems were being entered into the program with the appropriate characterization and significance.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

In October and November 2002, the inspectors reviewed the technical adequacy of multiple modifications associated with the Unit 1 extended power uprate. A list of the specific modification packages reviewed is included in the "List of Documents Reviewed" section of this report.

The inspectors verified that modification preparation, staging, and implementation did not impair the operations department's ability to complete emergency and abnormal operating procedure actions when required, to monitor key safety functions, or to respond to a loss of key safety functions. The inspectors reviewed the design adequacy of the modification by verifying the following:

- energy requirements were able to be supplied by supporting systems under accident and event conditions;
- replacement components were compatible with physical interfaces;
- replacement component properties met functional requirements under event and accident conditions;
- replacement components were environmentally and seismically qualified;
- sequence changes remained bounded by the accident analyses and loading on support systems was acceptable;

- structures, systems, and components response times were sufficient to serve accident and event functional requirements assumed by the design analyses;
- control signals were appropriate under accident and event conditions; and
- affected operations procedures were revised and training needs were evaluated in accordance with station administrative procedures.

The inspectors also verified that the post modification testing demonstrated system operability by verifying no unintended system interactions occurred, system performance characteristics met the design basis, and post-modification testing results met all acceptance criteria.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors observed and/or reviewed the following post maintenance testing activities during this inspection period:

Post Maintenance Activity	**Date Inspected**
Testing Following Modification of the 1A Standby Liquid Control Pump	October 18, 2002
Testing Following Replacement of the High Pressure Coolant Injection Turning Gear Time Delay Relay	October 24, 2002

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

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

.1 Pre-Outage Work Creates Unexpected Transients in Instrument Air System

a. Inspection Scope

The inspectors interviewed licensee personnel and reviewed work requests, condition reports, and procedures to determine the circumstances which led to two unexpected instrument air transients on October 24 and 25, 2002.

b. Findings

The inspectors identified one Green finding due to inadequate procedures and the failure to properly self-check prior to connecting temporary plant equipment to plant air systems. These deficiencies resulted in two separate instrument air system transients.

On October 14, 2002, a chemistry individual assisted a vendor in routing hoses for the moisture separator decontamination project by identifying the water and air connections to be used as directed by Work Order 369947, Task 09. Ten days later, the vendor directed several pipefitters to connect a decontamination skid to the air and water connections previously identified. Later the same afternoon, the vendor began using an air powered vacuum as part of the decontamination activities. Operations personnel immediately noticed abnormal fluctuations in instrument air pressure but were unaware an air powered vacuum was being used in the plant. The operators responded to the pressure fluctuations as required by procedure. However, they were unable to dispatch individuals to the field to search for the cause of the pressure fluctuations prior to the fluctuations stopping.

The next morning vendor personnel began using the same air powered vacuum. At 9:05 a.m., control room personnel received an alarm indicating that the Unit 2 backup service air valve was open. The operators discovered that the Unit 1A and Unit ½ instrument air compressors were continuously loaded and instrument air pressures were noted to be cycling between 91 and 98 pounds per square inch. Control room personnel dispatched several non-licensed operators and the field supervisor into the plant to observe air compressor operation and to look for possible air leaks. Operations personnel also started the Unit 2 instrument air compressor to assist in stabilizing the transient.

Approximately 2.5 hours after noticing the pressure fluctuations, a non-licensed operator discovered the vendor using the air powered vacuum. Additional investigation found that the vacuum had been powered using instrument air rather than service air. The non-licensed operator stopped the decontamination activities and closed the instrument air isolation valve. Instrument air pressures returned to normal.

A subsequent interview of the chemistry individual determined that an inadequate work procedure and improper self-checking contributed to connecting the air powered vacuum to the instrument air system rather than the service air system. Although Work Order 369947, Task 09, contained steps for the chemistry individual to assist in routing the hoses, specific equipment identification numbers were not provided. The chemistry individual stated that when he located the service water connection a Chicago fitting was present on the end of the line to allow the hose to be easily connected to the piping. When looking for the air connection, the chemistry individual noticed an air valve with a Chicago fitting installed on the end of the piping. The chemistry individual immediately assumed that this was the air supply line to be used during the decontamination project. Although the valve was properly labeled as an instrument air valve, the chemistry individual failed to check the valve tag.

The inspectors determined that connecting the air powered vacuum to the instrument air system rather than the service air system was more than minor because it: (1) involved the configuration control attribute of the Initiating Events cornerstone; and (2) affected the cornerstone objective of limiting the likelihood of those events that upset plant stability during power operations. The inspectors also determined that the error by the chemistry individual affected the cross-cutting area of Human Performance because, despite the inadequate procedure, the valve was properly labeled and self-checking should have been used to ensure that the proper air supply was identified.

The inspectors determined that this finding could be assessed using the significance determination process in accordance with Inspection Manual Chapter 0609, "Significance Determination Process," because the issue was associated with degraded conditions that could concurrently influence mitigating systems equipment and an initiating event. For the Phase 1 screening, the inspectors answered "yes" to Question 2 under the Initiating Events column which required a Phase 2 evaluation to be performed.

Using the Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 1, dated May 1, 2002, the inspectors determined that the finding's exposure time was less than three days and that the finding increased the likelihood of a loss of instrument air. These assumptions resulted in raising the Table 1 likelihood rating for a loss of instrument air by one decade or to a point value of 3. For the loss of instrument air worksheet, the inspectors determined that all mitigating systems capability was available. This resulted in four core damage sequences between 7 points and 13 points. The most dominant sequence involved the loss of instrument air with containment heat removal and long-term venting available. The inspectors concluded that the final significance determination process result for this finding was 7 points; therefore, this finding was considered to be of very low significance **(FIN 50-254/02-08-03; 50-265/02-08-03)**. No violation of NRC requirements was identified due to the instrument air system being non-safety-related. This issue was placed in the licensee's corrective action program via Condition Report 128977.

.2 <u>Stator Water Heat Exchanger Work Leads to Unit 1 Diesel Inoperability</u>

a. <u>Inspection Scope</u>

The inspectors interviewed licensee personnel and reviewed work instructions and condition reports to determine the circumstances which led to the unexpected inoperability of the Unit 1 emergency diesel generator.

b. Findings

The inspectors identified one Green finding due to the use of inadequate stator water heat exchanger work instructions and weak communications which resulted in rendering the Unit 1 emergency diesel generator inoperable.

On November 11, 2002, contractor personnel were performing work to replace the Unit 1A stator water heat exchanger tube bundle. Prior to performing this work, operations personnel had tagged out the heat exchanger for draining purposes. The contractors also established funnels and hoses for collecting the several gallons of water expected to be expelled from the heat exchanger as the tube bundle was removed. As the contractors began removing the tube bundle from the heat exchanger, a large amount of water (as much as 200 gallons) was expelled from the heat exchanger and overwhelmed the funnels and hoses. Within minutes the control room received alarms indicating a problem with the Unit 1 emergency diesel generator. A local operator reported that water from the heat exchanger had migrated into the diesel room and caused the circulating oil pump and the turbocharger lubricating oil pump to trip. Since the operators were unable to fully determine the extent of the water intrusion, the Unit 1 emergency diesel generator was declared inoperable.

Through interviews the inspectors determined that operations personnel were very aware that a large amount of water would be expelled from the stator water heat exchanger when the tube bundle was removed. In fact, the inspectors were informed that this was the reason that the out of service tagout for the stator water heat exchanger was considered an "exceptional" tagout. Operations personnel also told the inspectors that when mechanical maintenance personnel performed a stator water heat exchanger tube bundle replacement a large trough was used to catch the water. The inspectors interviewed the contractor personnel performing the heat exchanger work regarding the information provided by operations. The contractors stated that they were not made aware of the possibility for a large amount of water or that a trough had been used previously to catch the water. The inspectors also reviewed Work Order 99183182, Task 01, "Replace Tube Bundle Assembly in the 1-7401-A Stator Water Heat Exchanger," and found that the work order specifically stated that the heat exchanger would be isolated and drained.

The inspectors determined that the failure to have adequate stator water heat exchanger work instructions, and to communicate information regarding the amount of water, was more than minor because if left uncorrected the inadequate work instructions could continue to impact the availability, reliability, and capability of safety-related equipment. The inspectors also determined that the failure to ensure adequate work instructions were in place prior to removing the tube bundle also affected the cross-cutting area of Human Performance. Despite multiple individuals being aware that large amounts of water would be expelled during this work activity, actions were not taken to communicate this information to the contractors performing the work.

The Unit 1 emergency diesel generator was normally credited as an emergency power supply for Unit 1 equipment. At Quad Cities the Unit 1 emergency diesel generator was also credited as an emergency power source for common equipment such as the standby gas treatment and control room emergency ventilation systems. When this event occurred, Unit 1 was shut down for a refueling outage. The inspectors reviewed Inspection Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," Table 1 for a boiling water reactor in refueling operations with reactor vessel level greater than 23 feet. The inspectors determined that the significance determination process did not apply since the Unit ½ emergency diesel generator remained available to address accident situations while Unit 1 was shut down. In regards to Unit 2, the inspectors determined that this issue could be assessed using the At Power Significance Determination Process in accordance with Inspection Manual Chapter 0609, "Significance Determination Process," because the issue was associated with the operability, availability, reliability, or function of a system or train in a mitigating system. The inspectors performed a Phase 1 screening and determined that this issue was of very low risk significance (Green) since the finding did not represent an actual loss of safety function of a system or an actual loss of safety function of a single train for greater than its Technical Specification Allowed Outage Time **(FIN 50-265/02-08-04)**. No violations of NRC requirements were identified due to the stator water heat exchanger being non-safety related. This issue was included in the licensee's corrective action program as Condition Report 130694.

.3 Untimely Actions Result in Isolation of Decay Heat Removal System

a. Inspection Scope

The inspectors interviewed operations personnel and reviewed condition reports and procedures to determine the circumstances that led to an inadvertent isolation of the reactor water cleanup system while operating in the decay heat removal mode.

b. Findings

This self-revealing event led to the identification of one Green finding and a Non-Cited Violation for the failure to adequately implement QCOP 1200-15, "Operation of Decay Heat Removal Mode of RWCU [Reactor Water Cleanup] System," to ensure that the reactor water cleanup system did not isolate while being used to remove decay heat from the Unit 1 reactor vessel.

On November 24, 2002, operations personnel conducted hydrostatic testing on the Unit 1 reactor vessel. Upon completion of this test, operations personnel continued to remove decay heat from the reactor vessel using the reactor water cleanup system rather than the shutdown cooling mode of the residual heat removal system. At approximately 2:00 p.m., operations personnel made a control room log entry indicating that the reactor water cleanup system high temperature alarm and system isolation setpoints were set at 140 degrees as directed by QCOP 1200-13, "RWCU System High Temperature Isolation Setpoint Adjustment." Nine hours later the reactor water cleanup system isolated while operations personnel were attempting to adjust reactor building closed cooling water system temperature to maintain reactor vessel water temperature within the specified temperature band. Operations personnel were able to restart one of the reactor water cleanup pumps within eight minutes. Heatup of the reactor vessel water was minimal due to the low amount of decay heat present.

The inspectors reviewed QCOP 1200-15 and determined that Step D.2 contained a precaution warning that the reactor water cleanup system would isolate at 140 degrees if the reactor building closed cooling water heat removal capabilities were exceeded. The inspectors determined that operator error and a failure to perform adequate control room panel monitoring resulted in the failure to control reactor building closed cooling water temperature and prevent the reactor water cleanup system isolation. The inspectors determined that this issue was more than minor because it: (1) involved the human performance attribute of the barrier integrity cornerstone; and (2) affected the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. The inspectors also determined that the operator's error affected the cross-cutting area of Human Performance.

The inspectors determined that this issue could be assessed using the significance determination process since it was associated with maintaining the integrity of fuel cladding. Since Unit 1 was shut down when this event occurred, the inspectors reviewed Inspection Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process," Table 1 for a boiling water reactor in cold shutdown or refueling operation with a time to boil of greater than 2 hours and reactor coolant system level less than 23 feet above the top of the flange. Page T-21 of Table 1 required two residual heat removal shutdown cooling subsystems to be operable with one subsystem in operation. This statement was being met by operating the reactor water cleanup system in the decay heat removal mode. The inspectors referred to Page T-22 of Table 1 and determined that the inadvertent isolation of the reactor water cleanup system while in the decay heat removal mode of operation was of very low risk significance (Green). Specifically, the isolation did not significantly degrade the licensee's ability to recover decay heat removal once it was lost since the reactor water cleanup system was easily recoverable and either residual heat removal shutdown cooling subsystem could have been started to remove decay heat.

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. Section 3.c of Regulatory Guide 1.33 requires instructions for changing modes of operation for the shutdown cooling system. Contrary to the above, on November 24, 2002, operations personnel failed to properly implement QCOP 1200-15 to prevent a reactor water cleanup system isolation which resulted in changing modes of operation for the shutdown cooling system. This violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC's Enforcement Policy **(NCV 50-254/02-08-05)**. This issue was entered into the licensee's corrective action program as Condition Report 133054.

.4 Scaffold In Contact With Plant Equipment

a. Inspection Scope

The inspectors conducted periodic tours of plant facilities and identified multiple examples of outage related scaffolding that was in contact with plant equipment. The inspectors reviewed scaffolding erection procedures to determine if the scaffolding was constructed in accordance with procedural requirements.

b. Findings

The inspectors identified one Green Non-Cited Violation due to the failure to follow procedural requirements regarding the clearances required when erecting scaffolding near the residual heat removal system.

During a walkdown of the residual heat removal system on November 6, 2002, the inspectors identified that scaffolding was in contact with safety-related piping and valves. The inspectors also identified two other examples of scaffolding erection deficiencies concerning the Unit 1 torus shell and the Unit 1 reactor recirculation motor generator sets.

The inspectors reviewed Procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," Revision 1, and determined that scaffolding inspectors were required to verify that scaffolding was not supported by, in contact with or connected to safety-related equipment. The inspectors notified licensee personnel each time they identified an example of deficient scaffold erection. The inspectors noted that the licensee took timely action to address each scaffold erection issue. However, condition reports were not written for any of the inspector-identified issues. After several discussions regarding scaffold erection deficiencies during the resident inspectors' weekly management debrief, the licensee initiated Condition Report 131690 on November 14, 2002, to document the inspector-identified issues and to determine whether a common cause existed.

The licensee reviewed each scaffolding example and concluded that the equipment impacted remained operable. Therefore, each example was considered minor. However, in accordance with Inspection Manual Chapter 0612, Appendix B, "Issue Dispositioning Screening," and Appendix E, "Example of Minor Issues," Example 4.a., the inspectors determined that the improper scaffolding erection was more than minor because the number of examples identified demonstrated that workers routinely failed to follow Procedure MA-AA-796-024.

The inspectors determined that this finding could be assessed using the significance determination process. The inspectors determined that this finding was of very low safety significance (Green) since the scaffolding erection deficiencies did not result in a loss of function per Generic Letter 91-18, did not represent an actual loss of safety function of a system, did not represent an actual loss of safety function of a single train for greater than its Technical Specification Allowed Outage Time, did not represent an actual loss of safety function of one or more non-Technical Specification trains of equipment designated as risk significant per 10 CFR Part 50.65 for greater than 24 hours, and did not screen as potentially risk significant due to a seismic, fire, flooding, or severe weather initiating event.

Criterion V, "Instructions, Procedures, and Drawings," of 10 CFR Part 50, Appendix B, requires that activities affecting quality be performed in accordance with procedures. Scaffold installation was considered an activity affecting quality and was governed by

Procedure MA-AA-796-024. Contrary to the above, on November 6, 2002, the inspectors identified that the licensee failed to implement Procedure MA-AA-796-024 when erecting scaffolding near the residual heat removal system. This violation is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy (**NCV 50-254/02-08-06**). This issue was entered in the licensee's corrective action program as Condition Report 131690.

.5 General Outage Observations

a. Inspection Scope

The inspectors observed control room activities associated with the shutdown of Unit 1 for a scheduled refueling outage including removing equipment from service, inserting control rods, completing mode specific surveillance testing, and monitoring reactor coolant temperature. The inspectors attended daily outage meetings, reviewed outage control center and control room operator logs, and conducted daily control room tours to ensure that shutdown safety was maintained throughout the outage, reactor coolant system instrumentation provided accurate information, the decay heat removal systems were functioning properly, and inventory and reactivity controls were maintained. The inspectors conducted periodic observations of outage related work activities to ensure that work activities were performed in accordance with plant procedures. The inspectors performed tours of the turbine building, reactor building, and drywell to verify that procedural requirements regarding fire protection, foreign material exclusion, and the storage of equipment near safety-related structures, systems, and components were maintained.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- QCOS 6600-49, "Division 1 ECCS Automatic Actuation Test;"
- QCOS 6600-50, "Division 2 ECCS Automatic Actuation Test;" and
- QOS 6500-03, "Bus 14-1 Undervoltage Test."

The inspectors verified that the structures, systems, and components tested were capable of performing their intended safety function by comparing the surveillance procedure acceptance criteria and results to design basis information contained in Technical Specifications, the Updated Final Safety Analysis Report, and licensee procedures. The inspectors verified that the test was performed as written, the test data was complete and met the requirements of the procedure, and the test equipment range and accuracy was consistent with the application by observing the performance of the surveillance test. Following test completion, the inspectors conducted a walkdown of the test area to verify that the test equipment had been 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 documentation for the following temporary configuration changes:

- Installation of a temporary pump in the Unit 1 drywell equipment drain sump, and
- Installation of bladders in the Unit 1 main steam lines to establish secondary containment.

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

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 15 of the Quad Cities Station Annex to Exelon's Standardized Emergency Plan to determine whether changes identified in Revision 15 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.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Controls for Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns, Radiological Boundary Verifications and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors conducted walkdowns of the radiologically protected area to verify the adequacy of radiation area boundaries and postings including high and locked high radiation areas in the Unit 1 and 2 Reactor Buildings including the Unit 1 Drywell, and the Turbine Building. Confirmatory radiation measurements were taken to verify that these areas and selected radiation areas were properly posted and controlled in accordance with 10 CFR Part 20, licensee procedures, and Technical Specifications. The inspectors walked down areas having the potential for airborne activity and verified the adequacy of the licensee's continuous air monitoring systems and contamination controls. Selected radiation work permits (RWPs) for radiologically significant work being conducted during the refueling outage (Q1R17) were reviewed for protective clothing requirements and electronic dosimetry alarm set points for both dose rate and accumulated dose.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews

a. Inspection Scope

The inspectors observed work occurring on the refueling floor including diving and refueling operations. Work progress was observed in the reactor building, drywell, low pressure heater bay and the turbine building. RWP requirements and the As-Low-As-Reasonably-Achievable (ALARA) briefing packages for selected jobs were reviewed to assess their adequacy and to determine if job controls were implemented as intended. The inspectors determined if dosimetry placement, alarm set points, job site radiological surveys, radiological exposure estimates, contamination controls, airborne monitoring for radioactive materials, and postings were adequate given the jobs' radiological conditions.

b. Findings

No findings of significance were identified.

20S2 ALARA Planning and Controls (71121.02)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the plant's exposure history and trends, its three year rolling average dose and the impact of source term on radiological exposure under outage conditions, in order to assess radiological challenges for the current outage. The licensee's processes to estimate and track radiological exposure were discussed with radiation protection management to determine if the licensee's practices were appropriate.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning

a. Inspection Scope

The inspectors reviewed the station's processes for radiological work planning and scheduling, and evaluated the dose projection methodologies and practices implemented for the Q1R17 refueling outage, to verify that the technical bases for outage dose estimates were adequate. Specifically, the inspectors reviewed radiologically significant RWP/ALARA planning packages to verify that person-hour estimates, job history files, lessons learned, and industry experiences were utilized in the ALARA planning process. The inspectors also reviewed total effective dose equivalent ALARA evaluations to assess the licensee's analysis of evolutions involving potential airborne activity for the use of respiratory protection equipment. The inspectors also attended ALARA committee meetings and shift turnovers to further assess inter-departmental coordination and ownership in the radiological work/ALARA planning and scheduling processes.

b. Findings

No findings of significance were identified.

.3 Job Site Inspection and ALARA Control

a. Inspection Scope

The inspectors reviewed jobs being performed in areas of elevated dose rates, examined exposure estimates and work sites, and evaluated selected RWP's along with the associated ALARA briefing packages to verify that worker radiological exposure was minimized. Protective clothing requirements, dosimeter use including radiotelemetry dosimetry, and electronic dosimeter alarm set points were evaluated for consistency with RWP packages. The use of engineering controls were also reviewed to verify that worker exposures were maintained ALARA.

The inspectors attended selected pre-job ALARA and work control briefings, and observed portions of work evolutions directly and by using the licensee's remote closed circuit monitoring system in order to verify that adequate work controls were in place to maintain worker exposures ALARA. During job site walkdowns, radworkers and supervisors were observed to determine if low dose waiting areas were being used appropriately, and to evaluate the effectiveness of job supervision including equipment staging, use of shielding, availability of tools, and work crew size.

b. Findings

No findings of significance were identified.

.4 Radiation Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the licensee's Unit 1 outage dose goals and dose trending records, and evaluated the licensee's method for adjusting dose estimates to verify that the licensee had implemented sound radiation protection principles and properly identified work control problems. The inspectors also attended site ALARA committee meetings that discussed and approved dose adjustments for radiological work activities to assess the adequacy of management involvement in the ALARA program.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors 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 review of: (1) the results of a focus area self-assessment of the 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 and 2002.

The licensee's corrective action program for radiation protection issues was evaluated to verify that problems were appropriately prioritized and resolved in a timely manner, 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 CRs were evaluated.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation (71122.02)

.1 Walkdown of Radioactive Waste Systems

a. Inspection Scope

The inspectors reviewed the liquid and solid radioactive waste system description in the Final Safety Analysis Report and the most recent information regarding the types and amounts of radioactive waste generated and disposed. The inspectors performed walkdowns of the liquid and solid radwaste processing systems to verify that the systems agreed with the descriptions in the Final Safety Analysis Report and the Process Control Program, and to assess the material condition and operability of the systems. The inspectors reviewed the current processes for transferring waste resins into shipping containers to determine if appropriate waste stream mixing and/or sampling procedures were utilized. The inspectors also reviewed the methodologies for waste concentration averaging to determine if representative samples of the waste product were provided for the purposes of waste classification in 10 CFR 61.55. During this inspection, the licensee was not conducting waste processing.

b. Findings

No findings of significance were identified.

.2 Waste Characterization and Classification

a. Inspection Scope

The inspectors reviewed the licensee’s radiochemical sample analysis results for each of the licensee’s waste streams, including dry active waste, resins, and filters. The inspectors also reviewed the licensee’s use of scaling factors to quantify difficult-to-measure radionuclides (e.g., pure alpha or beta emitting radionuclides). The reviews were conducted to verify that the licensee’s program assured compliance with 10 CFR 61.55 and 10 CFR 61.56, as required by Appendix G of 10 CFR Part 20. The inspectors also reviewed the licensee’s waste characterization and classification program to ensure that the waste stream composition data accounted for changing operational parameters and thus remained valid between the annual sample analysis updates.

b. Findings

No findings of significance were identified.

.3 Shipment Preparation

a. Inspection Scope

Since there were no radioactive materials shipped from the site during the inspection, the inspectors reviewed the records of training provided to personnel responsible for the conduct of radioactive waste processing and radioactive shipment preparation activities. The review was conducted to verify that the licensee's program provided training consistent with NRC and Department of Transportation requirements.

b. Findings

No findings of significance were identified.

.4 Shipping Records

a. Inspection Scope

The inspectors reviewed five non-excepted package shipment documents completed during years 2001 and 2002, to verify compliance with NRC and Department of Transportation requirements (i.e., 10 CFR Parts 20 and 71 and 49 CFR Parts 172 and 173).

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed 2002 focus area self-assessments of the Radioactive Material Transportation and Radioactive Waste Processing Programs to evaluate the effectiveness of the self-assessment process to identify, characterize, and prioritize problems. The inspectors also reviewed corrective action documentation to verify that previous radioactive waste and radioactive materials shipping related issues were adequately addressed. The inspectors also selectively reviewed year 2002 CRs that addressed radioactive waste processing and radioactive materials shipping program deficiencies to verify that the licensee had effectively implemented the corrective action program.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstone: Mitigating Systems

.1 High Pressure Coolant Injection Safety System Unavailability

a. Inspection Scope

The inspectors reviewed control room logs, condition reports, and the licensee's monthly submittals of performance indicator information to verify the high pressure coolant injection safety system unavailability for both units from August 2001 to August 2002. The inspectors verified that the licensee accurately reported system performance as defined in the applicable revision of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline."

b. Findings

No findings of significance were identified.

Cornerstone: Barrier Integrity

.2 Reactor Coolant System Activity

a. Inspection Scope

The inspectors reviewed the licensee's reactor coolant system activity performance indicator to verify that the information reported by the licensee was accurate. The inspectors reviewed the licensee's reactor coolant sample results for maximum dose equivalent iodine-131 for the previous 4 quarters, and the licensee's sampling and analysis procedures. The inspectors also observed a chemistry technician obtain and analyze a reactor coolant sample.

b. Findings

No findings of significance were identified.

Cornerstone: Occupational Radiation Safety

.3 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's determination of performance indicators for the occupational radiation safety cornerstone to verify that the licensee accurately determined these performance indicators had all occurrences required. The inspectors reviewed CRs for the year 2002 and access control transactions for the year 2002.

During plant walkdowns the inspectors also verified the adequacy of postings and controls for locked high radiation areas, which contributed to the Occupational Exposure Control Effectiveness performance indicator.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

.4 RETS/ODCM Radiological Effluents

a. Inspection Scope

The inspectors reviewed the licensee's determination of performance indicators for the Radiological Effluent Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences. The inspectors reviewed CRs for the year 2002 and quarterly offsite dose calculations for radiological effluents for the previous 4 quarters.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 1B Reactor Recirculation Pump Trips on Overcurrent Condition

a. Inspection Scope

The inspectors assessed the circumstances surrounding the 1B reactor recirculation pump trip by interviewing site personnel and reviewing condition reports. The inspectors also reviewed the 1B reactor recirculation pump maintenance work history to determine if the current pump trip was similar to previous trips.

b. Findings

The inspectors identified one Green finding due to the failure to correct previously identified deficiencies with the 1B reactor recirculation motor generator voltage regulator.

On December 6, 2002, the 1B reactor recirculation pump tripped on an overcurrent condition. The licensee determined that voltage regulator instabilities caused by a lack of adequate capacitance in the regulator circuitry caused the pump trip. The inspectors reviewed Condition Reports 133549 and 133856 initiated on November 29 and December 3, 2002, respectively. The inspectors determined that both of the condition reports were written because the 1B reactor recirculation motor generator set failed to meet the acceptance criteria specified in Procedure MA-AB-772-301 during voltage regulator tuning activities.

The licensee evaluated the information in both condition reports and determined that continued operation of the 1B reactor recirculation pump was acceptable since the voltage regulator performance was similar to the performance experienced from February to November 2002. The licensee planned to add additional capacitance to the voltage regulator circuitry at a later date. The inspectors reviewed the licensee's decision to continue operating the 1B reactor recirculation pump and determined that previous and current operating conditions had changed. During the Unit 1 refueling outage, the licensee adjusted the voltage regulator stability and gain potentiometers on numerous occasions. However, it did not appear that the licensee adequately considered these subtle differences in performance prior to continuing operation.

The inspectors reviewed the 1B reactor recirculation pump maintenance work history and discovered that the pump had tripped twice in November 2000. The licensee's investigation determined that the pump trips occurred due to equipment failures and a lack of understanding for how the voltage regulator functioned. Corrective actions to prevent recurrence included component replacements and voltage regulator performance training. Based on the 1B reactor recirculation pump trip of December 6, 2002, the inspectors determined that the licensee's corrective actions to prevent recurrence were ineffective.

The failure to adequately address the 1B reactor recirculation motor generator voltage regulator failures was more than minor because the resulting pump trips could be reasonably viewed as a precursor to a significant event. The inspectors determined that this finding could be assessed using the significance determination process for the same reason. The inspectors conducted a Phase 1 screening and determined that this finding was of very low safety significance (Green) because it did not: (1) contribute to the likelihood of a primary or secondary system loss of coolant accident initiator; (2) contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available; (3) increase the likelihood of a fire or internal/external flood; or (4) increase the frequency of core damage scenarios of concern using the Individual Plant Examination for External Events or other plant specific analyses **(FIN 50-254/02-08-07)**. This issue was not subject to NRC enforcement since the reactor recirculation pump and the motor generator voltage regulator are non-safety-related components.

After the December 6, 2002, pump trip the licensee added approximately 500 microfarads of capacitance to the voltage regulator circuit and established an administrative limit which prevented operating the 1B reactor recirculation pump at greater than 92 percent speed. The licensee planned to install additional circuit capacitance on approximately January 6, 2003.

.2 <u>Routine Review of Identification and Resolution of Problems</u>

a. <u>Inspection Scope</u>

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action system at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Issues entered into the licensee's corrective action system as a result of inspectors' observations are generally denoted within the body of the report. Specific issues related to routine problem identification and resolution were discussed in Sections 1R20.4, 4OA2.1, and 4OA3.2 of this report.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) Licensee Event Report 50-265/02-004: Inadequate Separation in Both Trip Systems of the Scram Discharge Instrument Volume Input to the Reactor Protection System.

On August 2, 2002, the licensee determined that an engineering change (EC 24572), implemented in March 2002 resulted in the failure to maintain electrical separation between the safety-related reactor protection system cabling and the non-safety-related plant computer. Upon discovery the licensee entered Technical Specification 3.3.1.1, Condition B, which allowed 6 hours to place the reactor protection system in a tripped condition. The licensee installed a temporary modification within the 6 hours which disabled the scram discharge volume input to the plant computer.

The licensee failed to identify this electrical separation issue earlier due to a lack of rigor during the modification review process. The inspectors determined that this issue was minor since one channel in each reactor protection trip system remained operable. In the event that there had been an actual scram discharge volume high level condition, concurrent with the plant computer cabling and the reactor protection system wiring shorting together, the scram function would still have been initiated.

.2 (Closed) Licensee Event Report 50-265/02-005: Failure of Low Pressure Coolant Injection Logic Test due to Detached Wire.

During logic testing on the 2B residual heat removal subsystem on October 7, 2002, operations personnel were unable to complete a step in QCOS 1000-44, "Unit 2 B Loop Low Pressure Coolant Injection and Containment Cooling Modes of Residual Heat Removal Non-Outage Logic Test." Troubleshooting identified an unlanded wire that should have been connected to fuse holder FF-F11 within the residual heat removal logic circuitry. The licensee determined that the failure of the wire to be connected to the fuse holder resulted in the 2B residual heat removal subsystem being unable to automatically start in response to an emergency core cooling system initiation signal. The licensee also found that if the 2B residual heat removal subsystem was operating in torus spray or torus cooling certain valves would not have automatically closed upon the receipt of an emergency core cooling system initiation signal. As a result, low pressure injection from the 2A residual heat removal subsystem would have been diverted from the reactor vessel to the torus through the open torus cooling and/or torus spray valves until the operators manually closed the valves.

The inspectors determined that human performance and problem identification and resolution deficiencies contributed to the failure to identify and correct the residual heat removal wiring issue. On February 18, 2002, maintenance personnel performed activities inside the electrical panel containing fuse block FF-F11. The maintenance work conducted required fuse block FF-F11 to be moved; no wires were de-terminated from the fuse block. Following the electrical panel maintenance, personnel re-installed fuse block FF-F11 but did not visually or physically verify the integrity of any wiring connections. Testing following the maintenance demonstrated that the wiring connected to fuse block FF-F11 was in contact with the fuse block. However, the licensee believes the wiring was loose. Instrument maintenance personnel conducted several surveillances between March 18 and October 7, 2002, with unexpected results. Although actions were taken to document the unexpected results, the rigor in evaluating these results was less than adequate since equipment operability was not addressed.

On March 1, 2002, operations personnel completed QCOS 6600-48, "Unit 2 Division 2 Emergency Core Cooling System Simulated Automatic Actuation and Diesel Generator Auto-Start Surveillance." The test completion demonstrated that the wires associated with fuse block FF-F11 remained in contact with the fuse block. Approximately 2.5 weeks later, instrument maintenance personnel conducted QCIS 1000-13, "High Drywell Pressure Core Spray, Low Pressure Coolant Injection, and Emergency Diesel Generator Calibration and Functional Test." During this test the instrument technicians noticed that the residual heat removal lights for high drywell pressure did not illuminate as expected. One light flickered and extinguished; the other light never illuminated. Since the light illumination was not part of the QCIS 1000-13 acceptance criteria, the instrument technicians noted their observation and generated Work Order 421277 to investigate the light failure. Troubleshooting by the fix-it-now team determined that the light failures were not caused by burnt out bulbs. No other actions were taken to explain the significance or cause of the light failure. Instead Work Order 421277 was re-scheduled for completion during the May 2002 residual heat removal work week window. Prior to May 2002, Work Order 421277 was re-classified as outage work for unknown reasons. The inspectors noted that the next Unit 2 refueling outage was not scheduled until 2004. During performances of QCIS 1000-13 on June 13 and September 6, 2002, the instrument technicians continued to document the failure of the residual heat removal lights for high drywell pressure to illuminate. No actions were taken following the subsequent performances of QCIS 1000-13 due to the licensee's belief that the lights were for indication only.

The inspectors determined that the failure to adequately address the impact of the extinguished lights were more than minor because it: (1) involved the configuration control, equipment performance, and human performance attributes of the mitigating systems cornerstone; and (2) affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors also determined that this finding should be evaluated using the Significance Determination Process described in Inspection Manual Chapter 0609, "Significance Determination Process," because the finding was associated with the availability of a mitigating system. The inspectors conducted a Phase 1 screening and determined that a Phase 2 evaluation was required since the disconnected wire resulted in an actual loss of safety function of a single train for greater than the Technical Specification Allowed Outage Time. This finding also resulted in an actual loss of safety function of the residual heat removal system during times when the 2B system was operating in the torus cooling or torus spray modes.

The inspectors used the risk-informed inspection notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 1, dated May 2, 2002, to complete the Phase 2 evaluation. The inspectors determined that the exposure time was greater than 30 days which increased the initiating event likelihood for all initiating events by two orders of magnitude. For each worksheet the inspectors assumed that all mitigating capability was available except for both residual heat removal subsystems. The inspectors allowed credit for recovery since the residual heat removal system could be aligned for low pressure injection through manual operator actions. This resulted in 11 core damage sequences between 9 and 14 points. The most dominant core damage sequences involved: (1) the loss of the power conversion system with high pressure injection equipment and the core spray system available; (2) a large break loss of coolant accident with the core spray system available; and (3) a loss of offsite power with the high pressure injection systems and the core spray system available. The inspectors concluded that the final significance determination process result for this finding was 9 points; therefore, this finding was considered to be of very low risk significance (Green).

Technical Specification 3.5.1, “Emergency Core Cooling System - Operating,” requires that each emergency core cooling system injection and/or spray subsystem be operable in Modes 1, 2, and 3. Technical Specification 3.5.1, Condition B, allows one residual heat removal subsystem to be inoperable for up to 7 days. Condition C of the same Technical Specification allows both residual heat removal subsystems to be inoperable for up to 72 hours. The inspectors determined that as of March 18, 2002, the 2B residual heat removal subsystem, an emergency core cooling system, was inoperable. In addition, both residual heat removal subsystems were inoperable at various times between March 18 and October 7, 2002. This determination was based upon the fact that as of March 18 the licensee was no longer able to ensure that the wire was adequately secured to fuse block FF-F11. The failure to have both residual heat removal subsystems operable while operating in Modes 1, 2, and 3 was considered a Non-Cited Violation of Technical Specification 3.5.1 in accordance with Section VI.A.1 of the NRC’s Enforcement Policy **(NCV 50-265/02-08-08)**. This issue was entered into the licensee’s corrective action program as Condition Report 126235.

.4 Unit 1 in Single Loop Operation Due to 1B Reactor Recirculation Pump Trip

On December 6, 2002, the inspectors reviewed the circumstances surrounding the 1B reactor recirculation pump trip. The inspectors reviewed the timeliness and adequacy of operator actions during the transient condition. The inspectors determined that the operators reacted appropriately and followed procedural requirements during the transient condition. The inspectors also determined through observation that the operators appropriately implemented procedures to allow the unit to operate in single loop operations during the troubleshooting and reactor recirculation pump restoration activities. Further information regarding the incident is described in Section 4OA2 of this report.

4OA4 Cross-Cutting Findings

.1 Human Performance Related Findings

Findings described in Sections 1R20.1, 1R20.2, 1R20.3, and 4OA3.2 of this report had one or more human performance deficiencies which caused the event to occur. An individual failed to use self-check techniques when identifying the proper plant air supply for an air powered vacuum. This error resulted in two separate instrument air transients on October 24 and 25, 2002 (see Section 1R20.1).

A communications weakness between operations, maintenance and contractor personnel resulted in a large amount of water being expelled from a stator water heat exchanger during maintenance. The water migrated to the room below and resulted in the Unit 1 emergency diesel generator being declared inoperable (see Section 1R20.2).

Failure to follow procedures and untimely control room panel monitoring led to the unexpected isolation of the reactor water cleanup system while the system was being used to remove decay heat during the Unit 1 refueling outage (see Section 1R20.3).

Lastly, the failure to verify the physical integrity of wiring connections following maintenance activities led to a condition which resulted in the 2B residual heat removal system being inoperable for more than 6 months (see Section 4OA3.2).

.2 Problem Identification and Resolution Related Findings

The licensee did not initiate condition reports following the inspectors identification of multiple scaffolding erection deficiencies (see Section 1R20.4). As a result, additional scaffolding deficiencies were identified by other plant personnel. Later in the inspection period, the licensee initiated a condition report encompassing all of the inspector identified scaffolding issues. Once this action was taken, the licensee began conducting an evaluation to determine whether a common cause had contributed to some or all of the identified deficiencies.

Weaknesses in problem evaluation resulted in the failure to correct deficiencies with the 1B reactor recirculation voltage regulator (see Section 4OA2.1). On November 29 and December 3, 2002, the licensee initiated two condition reports due to the 1B reactor recirculation pump voltage regulator failing to meet proceduralized acceptance criteria. During the evaluation of these condition reports, the licensee did not fully consider changes made to the voltage regulator during the outage and power ascension. These actions resulted in Unit 1 being at an increased risk for a plant transient and a subsequent reactor recirculation pump trip on December 6, 2002.

Deficiencies in problem evaluation and prioritization also led to the failure to recognize that the 2B residual heat removal system was inoperable (see Section 4OA3.2). The inspectors determined that licensee personnel had at least three prior opportunities to identify this condition prior to discovery of the condition on October 7, 2002. These opportunities were not acted upon due to the licensee's belief that an extinguished light was for indication only rather than a sign of equipment malfunction.

4OA5 Other Activities

.1 Completion of Appendix A to TI 2515/148, Revision 1

The inspectors completed the pre-inspection audit for interim compensatory measures at nuclear power plants, dated September 13, 2002.

.2 Power Uprate

a. Inspection Scope

The inspectors observed control room activities associated with the Unit 1 power uprate including power ascension testing and surveillance testing. The inspectors also reviewed daily licensee power uprate observations and evaluations to ensure deficiencies were adequately evaluated. The inspectors performed tours of the turbine building and reactor building to assess plant conditions as power ascension activities progressed. The inspectors reviewed plant modification plans and post-modification testing.

b. Findings

No findings of significance were identified.

4OA6 Meetings

.1 Exit Meeting

The inspectors presented the inspection results to Mr. T. Tulon and other members of licensee management at the conclusion of the inspection on December 31, 2002. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Temporary Instruction 2515/148, Appendix A with Mr. B. Swenson on October 25, 2002.
- Access Control, ALARA Planning and Control, and Radwaste and Transportation with Mr. T. Tulon on November 15, 2002.
- Inservice Inspection with Mr. T. Tulon on November 21, 2002.

4OA7 Licensee-Identified Violations

The following violations of very low significance were identified by the licensee and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Manual, NUREG-1600, for being dispositioned as Non-Cited Violations.

Cornerstone: Mitigating Systems

Technical Specification Surveillance Requirement 3.8.4.7 requires that the licensee verify that battery capacity is adequate to supply, and maintain in an operable status, the required emergency loads for the design duty cycle every 24 months. As described in Condition Report 124350, on September 24, 2002, the licensee had not included charging spring motor loads for certain General Electric 480 Volt breakers as part of the design duty cycle during previous battery testing. As a result, the license had not adequately performed the surveillance testing required by Technical Specification Surveillance Requirement 3.8.4.7.

The licensee entered Technical Specification Surveillance Requirement 3.0.3 in response to the missed surveillance test. This surveillance requirement allowed the licensee to delay entry into Technical Specification 3.8.7 due to the discovery of missed surveillances as long as the a risk evaluation was performed within 24 hours and the missed surveillance tests were completed within the Technical Specification specified frequency (in this case 24 months). The inspectors reviewed the licensee's risk assessment and determined that the risk to the plant from the missed surveillances was very low since calculations showed that adequate battery capacity was available to supply all required loads. Subsequent testing of the Unit 1 and 2 batteries also demonstrated that adequate capacity was available to supply the required loads.

KEY POINTS OF CONTACT

Licensee

T. Tulon, Site Vice President
B. Swenson, Plant Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
G. Boerschig, Work Control Manager
R. Gideon, Engineering Manager
K. Hungerford, Wackenhut Project Manager
A. Javorik, Maintenance Manager
M. Karney, Midwest ROG Security Manager
K. Leech, Security Manager
K. Moser, Chemistry/Environ/Radwaste Manager
M. Perito, Operations Manager
M. Snow, Nuclear Oversight Manager

Nuclear Regulatory Commission

M. Ring, Chief, Reactor Projects Branch 1
C. Lyon, Project Manager
K. Ohr, Radiation Protection Supervisor

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/02-08-01 50-265/02-08-01	FIN	Inadequate Design Leads to Delay in Discovering Safe Shutdown Makeup Pump was Inoperable due to Strainer Clogging
50-254/02-08-02 50-265/02-08-02	URI	Resolution of American Society of Mechanical Engineers Requirements
50-254/02-08-03 50-265/02-08-03	FIN	Inadequate Procedure and Self Checking Results in Connecting Air Powered Vacuum to Instrument Air System and two Air Transients
50-265/02-08-04	FIN	Inadequate Procedure and Communication Weaknesses Leads to Emergency Diesel Generator Inoperability
50-254/02-08-05	NCV	Failure to Follow Procedure and Weak Control Board Monitoring Leads to Inadvertent Reactor Water Cleanup Isolation
50-254/02-08-06	NCV	Multiple Examples of Scaffolding in Contact with Safety-Related Equipment

50-254/02-08-07	FIN	Weaknesses in Problem Identification and Resolution Leads to 1B Reactor Recirculation Pump Trip
50-265/02-08-08	NCV	Human Performance and Problem Identification and Resolution Results in Failure to Discover Impact of Loose Lead on Residual Heat Removal Inoperability

<u>Closed</u>

50-254/02-08-01 50-265/02-08-01	FIN	Inadequate Design Leads to Delay in Discovering Safe Shutdown Makeup Pump was Inoperable due to Strainer Clogging
50-254/02-08-03 50-265/02-08-03	FIN	Inadequate Procedure and Self Checking Results in Connecting Air Powered Vacuum to Instrument Air System and two Air Transients
50-265/02-08-04	FIN	Inadequate Procedure and Communication Weaknesses Leads to Emergency Diesel Generator Inoperability
50-254/02-08-05	NCV	Failure to Follow Procedure and Weak Control Board Monitoring Leads to Inadvertent Reactor Water Cleanup Isolation
50-254/02-08-06	NCV	Multiple Examples of Scaffolding in Contact with Safety-Related Equipment
50-254/02-08-07	FIN	Weaknesses in Problem Identification and Resolution Leads to 1B Reactor Recirculation Pump Trip
50-265/02-08-08	NCV	Human Performance and Problem Identification and Resolution Results in Failure to Discover Impact of Loose Lead on Residual Heat Removal Inoperability
50-265/02-004	LER	Inadequate Separation in both Trip Systems of the Scram Discharge Instrument Volume Input to the Reactor Protection System
50-265/02-005	LER	Failure of Low Pressure Coolant Injection Logic Test due to Detached Wire

<u>Discussed</u>

None

LIST OF ACRONYMS USED

ALARA	As-Low-As-Is-Reasonably-Achievable
ADAMS	Agencywide Documents Access and Management System
CFR	Code of Federal Regulations
CR	Condition Report
FIN	Finding
IMC	Inspection Manual Chapter
NCV	Non-Cited Violation
PARS	Publically Available Records System
RWP	Radiation Work Permit
SDP	Significance Determination Process

LIST OF DOCUMENTS REVIEWED

1R01 Adverse Weather

QCOP 0010-01; Winterizing Checklist; Revision 17

QCOP 0010-02; Required Cold Weather Routines; Revision 12

Quad Cities Winter Readiness Operating Experience

IE Bulletin 79-24; Frozen Lines; dated September 27, 1979

Licensee's Response to IE Bulletin 79-24; dated October 30, 1979

List of Open Work Requests on the Ice Melt Valve and Heat Tracing System

Winter Readiness 2002-2003 Open Items List

OP-AA-108-109, Attachment 3; System Engineering System Readiness Review; various dates

Condition Report 79845; Clean Demineralizer Suction Piping Installed At Risk; dated October 23, 2001

Condition Report 80242; Unit 2 Traveling Screen High Differential Pressure Due to Shear Pin Failure; dated October 25, 2001

Condition Report 81415; Cold Weather Preparations; dated November 2, 2001

Condition Report 82901; Ice Melt Valve - Limitorque Failure, Damage to Worm/Worm Gear; dated November 14, 2001

Condition Report 93918; Unit 1 Startup Delayed 24 Hours Due to CIV #1 Stuck Closed; dated February 4, 2002

Condition Report 98562; High Traveling Screen Differential Pressure Alarm on Unit 2; dated March 10, 2002

Condition Report 112590; U-1 and 2 HRSS Sample Heat Trace Circuits Turned Off; dated June 20, 2002

Condition Report 127693; Corrective Action Work Request Canceled; dated October 16, 2002

Condition Report 127842; Need to Inspect Duct for Foreign Material; dated October 17, 2002

Condition Report 127679, Safe Shutdown Makeup Pump Room Observed Warmer Than Usual; dated October 16, 2002

Apparent Cause Evaluation for Condition Report 127679; dated October 25, 2002

QCMPM 2900-01; Unit ½ Safe Shutdown Pump Room Air Handling Unit Cooling Service Water Strainer Preventive Maintenance; Revision 4; dated August 30 - October 31, 2002

Exelon Quality Assurance Topical Report; Revision 69

1R05 Fire Protection

Quad Cities Pre-Plan TB-69; Unit 1 Turbine Building, Elevation 595'-0" Hallway Fire Zone 8.2.6.A

Quad Cities Pre-Plan TB-66; Unit 1 Turbine Building, Elevation 572'-6" CRD Pumps Fire Zone 8.2.3.A

Quad Cities Pre-Plan TB-68; Unit 1 Turbine Building, Elevation 595'-0" Low Pressure Heater Bay Fire Zone 8.2.6.B

Quad Cities Pre-Plan RB-24; Unit ½ Reactor Building, Elevation 690'-6" Refuel Floor

Quad Cities Pre-Plan RB-16; Unit 2 reactor Building, Elevation 554'-0" NW Corner Room - 2A Core Spray Fire Zone 11.3.3

Quad Cities Pre-Plan RB-17; Unit 2 Reactor Building, Elevation 554'-0" SE Corner Room - 2B RHR Room Fire Zone 11.3.2,

Quad Cities Pre-Plan RB-18; Unit 2 Reactor Building, Elevation 554'-0" NE Corner Room - 2A RHR Room Fire Zone 11.3.4,

Quad Cities Station Units 1 and 2 Fire Hazards Analysis; dated August 2001

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

OP-AA-201-004; Fire Prevention for Hot Work; Revision 5

OP-AA-201-008; Pre-Fire Plans; Revision 1

OP-AA-201-009; Control of Transient Combustibles; Revision 2

1R08 Inservice Inspection

ER-AA-335-005; Radiographic Examination; Revision 0

PT-EXLN-104V0; Procedure for Liquid Penetrant Examination Color Contrast (Visible) Solvent Removable; dated November 7, 2001

GE-UT-311; Procedure for Manual Ultrasonic Examination of Nozzle Inner Radii and Bore; dated January 9, 2001

GE-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds; dated October 24, 2002

GE-PDI-UT-2; PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds; dated October 24, 2002

ISI Program Plan, Third 10-Year Inspection Interval, Quad Cities Station, Units 1 & 2; dated May 22, 2001

Quad Cities Generating Station Unit 2, Post Outage (90 Day) Summary Report, Refueling Outage Q2R16; dated June 3, 2002

Action Report 00132057; NRC's Position Regarding CRD Housing Weld Inspections

Action Report 00113995; Dresden Missed Inspections of CRD Housing Welds (Condition Report 113590)

Radiographic Examination Report RT-005; dated November 20, 2002

1R11 Licensed Operator Requalification

Scenario 00-28; Torus Narrow Range Instrument Failure, Loss of Coolant Accident Inside Containment, and an Anticipated Transient Without Scram; Revision 10

QCOA 0201-01; Increasing Drywell Pressure; Revision 15

QCOP 0300-28; Alternate Rod Insertion; Revision 18

QCOA 0400-01; Reactivity Addition; Revision 13

QCOA 3200-01; Reactor Feed Pump Auto Trip; Revision 11

QGA 100; Reactor Pressure Vessel Control; Revision 7

QGA 101; Reactor Pressure Vessel Control (Anticipated Transient Without Scram); Revision 10

QGA 200; Primary Containment Control; Revision 8

1R13 Maintenance Risk Assessment and Emergent Work

OU-AA-103; Shutdown Safety Management Program; Revision 1

Work Week Safety Profile; Week of December 9, 2002

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

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

Online Work Schedules; Week of December 9, 2002

1R14 Non-Routine Evolutions

QCGP 3-1; Reactor Power Operations; Revision 29

QCGP 3-2; Control of Planned Reactor Power Changes; Revision 13

QCGP 4-1; Control Rod Movements and Control Rod Sequences; Revision 22

1R15 Operability Evaluations

Condition Report 132057; NRC's Position Regarding Control Rod Drive Housing Weld Inspections; dated November 17, 2002

Condition Report 124350; Certain General Electric 480 Volt Breakers not Properly Modeled in ELMS-DC Database; dated September 24, 2002

Condition Report 131936, "Unit 2 Main Steam Isolation Valves 2-0203-2B and 2-0203-2C Contain Belleville Springs in the Low Liner Assembly Which are Suspect for Potential Failure; dated November 20, 2002

1R16 Operator Workarounds

OP-AA-101-103; Operator Work-Around Program; Revision 0

List of Open Operator Workarounds and Operator Challenges; dated October 10, 2002

Condition Report 110692; Work on Valve 1-2001-794 Rescheduled due to Welding Resources and Pipe Interference; dated June 5, 2002

OP-AA-108-102; Equipment Status Tag Log; dated October 11, 2002

Unit 1 Nuclear Station Operator Turnover Checklist; dated October 11, 2002

Unit 2 Nuclear Station Operator Turnover Checklist; dated October 11, 2002

Temporary Configuration Change Report; dated October 11, 2002

Operability Determinations with Open Compensatory Actions or Corrective Actions Log; dated October 11, 2002

Operator Burden Review; dated July 2002

Operator Burden Review; dated October 2002

1R17 Permanent Plant Modifications

Engineering Change Package 24165; Trip Condensate/Booster Pump 1D on Loss of Coolant Accident and With All four Condensate/Booster Pumps 1A, 1B, 1C, and 1D Running; dated May 9, 2001

Engineering Change Package 24169; Main Steam Flow High Setpoint Change and Differential Pressure Switch Replacement; dated January 16, 2001

Engineering Change Package 24420; Reactor Feed Pump and Motor Generator Set Breaker Time Delay Modification; dated June 5, 2001

Engineering Change Package 337693; Isophase Bus Duct Cooling System Upgrade to Support Extended Power Uprate Operation

Calculation QDC-3000-I-0986; Main Steam Line High Flow Differential Pressure Switch Setpoint Error Analysis; Revision 0

Engineering Change 24432; Extended Power Uprate Project Main Steam Pipe Support Project Main Steam Pipe Support and Drywell Steel Modifications; Revision 3

1R19 Post Maintenance Testing

QCOS 1100-07; SBLC Pump Flow Rate Test; Unit 1, Revision 22

QOM 1-1100-01; U1 Standby Liquid Control Valve Check List; Revision 9

QCOS 2300-28; HPCI Turning Gear Logic Functional Test; Revision 8

Work Order 416235-01; Replace Agastat Time Delay Relay 1-2300-121 in Panel 901-39; dated October 22, 2002

Engineering Change Request 51124; Obtain Time Delay Criteria for 2330-121 Relay; dated September 16, 1998

Drawing 4E-1526; Schematic Control Diagram HPCI System Block Diagram 8 Control Switch Development; Revision T

Drawing 4E-1527; Schematic Diagram High Pressure Coolant Injection System Sensors and Auxiliary Relays; Sheet 1; Revision R

Drawing 4E-1527; Schematic Diagram High Pressure Coolant Injection System Sensors and Auxiliary Relays; Sheet 2; Revision H

Drawing 4E-1527; Schematic Diagram High Pressure Coolant Injection System Sensors and Auxiliary Relays; Sheet 3; Revision M

Drawing 4E-1532; Schematic Diagram High Pressure Coolant Injection System Turbine Auxiliary Pumps; Revision AA

1R20 Refueling and Outage

Condition Report 128977; Moisture Separator Decon Work Used IA Instead of SA; dated October 25, 2002

Work Order 369947; Moisture Separator Decontamination Work

Units 1 and 2 Control Room Logs; dated October 24-25, 2002

Condition Report 130694, Stator Water Heat Exchanger Spill; dated November 7, 2002

Out of Service Tagout 00011947

Work Order 99183182, Task 01; Replace Tube Bundle Assembly in the 1-7401-A Stator Cooling Water Heat Exchanger

Condition Report 133054; Unit 1 RWCU Isolation; dated November 24, 2002

Unit 1 Control Room Logs; dated November 24, 2002

QCOP 1200-15, Operation of Decay Heat Removal Mode of RWCU System; Revision 13

QCOP 1200-13, RWCU System High Temperature Isolation Setpoint Adjustment; Revision 3

Unit 1 Main Condenser Clearance Order 00011583

Unit 1 High Pressure Coolant Injection Clearance Order 00012820

Procedure OU-AA-103; Shutdown Safety Management Program; Revision 1

Procedure OU-QC-104; Shutdown Safety Management Program Quad Cities Annex; Revision 2

QCOA 1000-02; Loss of Shutdown Cooling; Revision 12

QCOS 1000-24; Shutdown Cooling Outage Report; Revision 5

QCOP 1000-38; Alternate Shutdown Cooling; Revision 3

QCOA 1000-03; RHR Pump Trip; Revision 6

QCOP 1000-17; Shutdown Cooling, Reactor Temperature Trending; Revision 11

QCOP 1000-05; Shutdown Cooling Operation; Revision 30

QCOP 1200-15; Operation of Decay Heat Removal Mode of Reactor Water Cleanup System; Revision 13

QCGP 1-1; Normal Unit Startup; Revision 44

QCGP 3-1; Reactor Power Operations; Revision 29

OP-AA-108-108; Unit Restart Review; Revision 0

Shutdown Safety Risk Profile Worksheets; dated November 5 - November 25, 2002

Condition Report 131936; Missing Belleville Washer in 1-0203-2C Main Steam Isolation Valve; dated November 5, 2002

Condition Report 130946; Parts Found in Turbine Stop Valve Strainer; dated November 8, 2002

Technical Evaluation of Degraded Main Steam Isolation Valve Belleville Springs Identified During Q1R17

Indication Notification Report Q1R17-02-01; Steam Dryer; dated November 8, 2002

Condition Report 130921; Deformed Steam Dryer Exhaust Skirt and Cracked Tie Bar Weld; dated November 8, 2002

Engineering Change 24495; Power Uprate - Modify Reactor Vessel Steam Dryer to Reduce Moisture Carryover; dated November 12, 2002

Letter from Mark O. Lenz and James D. Adam, General Electric to Bruce Phares, Exelon Nuclear; Re: Quad Cities Unit 1, Jet Pump 16 Slip Joint; dated November 15, 2002

1R22 Surveillance Testing

QOS 6500-03; Undervoltage Functional Test 4 KV Bus 14-1; Revision 21

QCOS 6600-49; Division 1 ECCS Automatic Actuation Test; Revision 5

QCOS 6600-50; Division 1 ECCS Automatic Actuation Test; Revision 6

Technical Specifications

Updated Final Safety Analysis Report

1R23 Temporary Plant Modifications

Engineering Change Request 357803; dated 11/11/02

Engineering Change 339810; Revision 1

Temporary Interim Change Procedure 576; Drywell Equipment Drain Sump Temporary Pump Installation; dated 11/13/02

CC-AA-112; Temporary Configuration Changes; Revision 5

Engineering Change 339708; Installation of Temporary Bladders to Maintain Secondary Containment; dated November 7, 2002

10 CFR 50.59 Screening QC-S-2002-0376; Installation of Temporary Bladders to Maintain Secondary Containment; dated November 7, 2002

QCMM 0203-03; Installation, Maintenance, and Removal of Line Plugs in the Main Steam Line to Provide Secondary Containment with the MSIV Room Part of the Turbine Building; Revision 0

Updated Final Safety Analysis Report

Technical Specifications

2OS1 Access Control

2OS2 ALARA Planning and Controls

10001409; RWP/ALARA Plan/Work In Progress Review: U1 Moisture Separators: Chem Decon; Revision 2

10001341; RWP/ALARA Plan: U1 Main Turbine Overhaul/PM; Revision 2

10001253; RWP/ALARA Plan: ERV/SRV/Target Rock Valves: Remove/Replace; Revision 3

10001289; RWP/ALARA Plan: Overhaul B, C, D Inboard MSIVs; Revision 1

10001909; RWP/ALARA Plan: U1 Steam Dryer Cover Plate Mod: Diving Activities: Diving Activities; Revision 1

10001362; RWP/ALARA Plan: U1 Reactor Steam Dryer: Mod To Reduce Carryover (Divers); Revision 0

10001341; RWP-TEDE ALARA Evaluations; Revisions 1 and 2

Trend Charts, Unit 1 Soluble/Insoluble Cobalts 58/60; from June 1998 through November 2002

Exposure Reduction Charter; Revision 2

Reactor Coolant I-131 Equivalent from May 15, 2002 through October 2, 2002

Reactor Coolant Neptunium 239 from May 15, 2002 through September 4, 2002

Unit 1 Dose Equivalent Iodine from November 5, 2000 through November 5, 2002

RP-AA-441; Evaluation and Selection Process For Radiological Respirator Use; Revision 2

QCCP 0200-01; Reactor Water Iodine Analysis; Revision 11

Performance Indicator Data (Effluents) from October 2001 through September 2002

Performance Indicator Data (Occupational) from October 2001 through September 2002

Dose Equivalent Iodines U1/U2 from October 2001 through September 2002

Drywell Survey Map 579 Elevation; dated November 5, 2002

Drywell Survey Map 592 Elevation; dated November 8, 2002 Drywell Survey Map 614 Elevation; dated November 7, 2002

Drywell Survey Map 640 Elevation; dated November 9, 2002

Drywell Survey Map 652 Elevation; dated November 9, 2002

105357; Nuclear Oversight Identified Deficiencies in RP Documentation Reviews In First Quarter Assessment; dated April 25, 2002

107216; Contamination Found in Clean Area In U2 5 Rack; dated May 15, 2002

104218; 2B RHR Room Cooler Work Scope Not Properly Communicated To RP; dated April 16, 2002

103141; Erroneous ED Record Without Proper Follow up Causes RWP Lock; dated April 10, 2002

127222; Elevated Dose Rates in Rad Waste Basement; dated October 11, 2002

127441; Poor Rad Worker Practices Identified; dated October 17, 2002

128774; High radiation Area Identified in Radwaste Max Recycle; dated October 4, 2002

Q1R17 Dose Estimates; dated November 7, 2002

Q1R17 Outage Dose Estimate Review; dated November 12, 2002

2PS2 Radioactive Material Processing and Transportation

Focus Area Self-Assessment Report, Radioactive Material Transportation; dated July 30, 2002

Focus Area Self-Assessment Report Radiation, Radwaste; dated May 16, 2002

RW-AA-100; Process Control Program for Radioactive Wastes; Revision 2

QCRP 5620-0610; CFR 61 Waste Stream Sampling and Analysis; Revision 2

RP-AA-600; Radioactive Material/Waste Shipments; Revision 5

Shipment No QC-01-307 Type B, Y-III, Irradiated Hardware; dated April 20, 2001

Shipment No QC-01-311 Type B, Y-III, Irradiated Hardware; dated May 4, 2001

Shipment No QC-02-328 Type A, Y-III, Control Rod Drives; dated February 20, 2002

Shipment No QC-02-001 LSA II, Y-III, Dewatered Resin; dated June 4, 2002

Shipment No QC-02-324 SCO I, Safety Valves; dated February 17, 2002

AR 00076148Q2001-02884; RAM Shipping Personnel Not Trained IAW IATA; dated September 17, 2001

AR 00090308; Improper Unloading of a Radioactive Material Shipment; dated January 14, 2002

AR 00100601; HIC Dose Rate Higher Than Normal; dated March 22, 2002

AR 00123322; Water in Radioactive Shipment; dated September 18, 2002

4OA1 Performance Indicator Verification

Nuclear Energy Institute Document 99-02; Regulatory Assessment Performance Indicator Guideline; Revision 2

LS-AA-2050; Monthly Performance Indicator Data Elements for Safety System Unavailability-High Pressure Injection (BWR) or High Pressure Safety Injection (PWR); Revision 2; dated August 2001-August 2002

4OA3 Event Followup

Updated Safety Analysis Report

Technical Specifications

Condition Report 126235; While Performing QCOS 1000-44 2B RHR Logic Test, Could Not Complete Step H.4.1.1; dated October 7, 2002

Prompt Investigation for Condition Report 126235; Disconnected Lead Found During U2 LPCI Logic Test; dated October 7, 2002

Management Review Committee Update; RHR Logic Test Failure due to Detached Lead; dated October 29, 2002

QCOP 0202-21, “Unit 1 Reactor Recirculation System Shutdown of One Pump,” Revision 4

QCOP 0202-07, “Reactor Recirculation Single Loop Operation Determination of Total Core Flow,” Revision 12

QCOP 0202-02, “Reactor Recirculation System Startup,” Revision 24

QCOP 0202-13, “Reactor Recirculation Flow Control Line Determination,” Revision 7

TIC-510, “Quad Cities Unit 1 EPU Power Ascension Test Procedure”

Engineering Change 24495; Power Uprate - Modify Reactor Vessel Steam Dryer to Reduce Moisture Carryover; dated November 12, 2002

Engineering Change 337693; Isophase Bus Duct Cooling Modification; dated October 4, 2002

Work Order 453748; Remove and replace Modified Standby Liquid Control Relief Valves for EPU

EC 24165; Trip Condensate/Booster Pump 1D on Loss of Coolant Accident and With All Four Condensate/Booster Pumps 1A, 1B, 1C, and 1D Running; dated May 9, 2001

EC 24169; Main Steam Flow High Setpoint Change and Differential Pressure Switch Replacement; dated January 16, 2001

EC 24420; Reactor Feed Pump and Motor Generator Set Breaker Time Delay Modification; dated June 5, 2001

Calculation QDC-3000-I-0986; Main Steam Line High Flow Differential Pressure Switch Setpoint Error Analysis; Revision 0

EC 24432; Extended Power Uprate Project Main Steam Pipe Support Project Main Steam Pipe Support and Drywell Steel Modifications; Revision 3

4OA7 Licensee-Identified Violations

Condition Report 124350; Certain General Electric 480 Volt Breakers not Properly Modeled in ELMS-DC Database; dated September 24, 2002

Risk Management Documentation Number SA-1114; Technical Specification Surveillance Requirement 3.0.3 Risk Evaluation of Revised 125 V Direct Current Profile; dated October 4, 2002