April 19, 2004

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

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000254/2004002; 05000265/2004002

Dear Mr. Crane:

On March 31, 2004, 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 April 6, 2004, with Mr. Tulon and other members of your staff.

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

Based on the results of this inspection, the inspectors identified one finding of very low safety significance (Green) which was determined to involve a violation of NRC requirements. However, because this violation was of very low safety significance and because it was entered into your corrective program, the NRC is treating this finding as a Non-Cited Violation in accordance with Section V1.A.1 of the NRC's Enforcement Policy.

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

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

Sincerely,

***/RA/***

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

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

Enclosure: Inspection Report 05000254/2004002; 05000265/2004002
w/Attachment: Supplemental Information

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

DOCUMENT NAME: G:\quad\ML041120590.wpd

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

| OFFICE | RIII | N | RIII | E | | | | |
|---|---|---|---|---|---|---|---|---|
| NAME | MRing for PPelke/ | | MRing | | | | | |
| DATE | 04/19/04 | | 04/19/04 | | | | | |

***OFFICIAL RECORD COPY***

ADAMS Distribution:
AJM
DFT
LWR
RidsNrrDipmIipb
GEG
HBC
KKB
C. Ariano (hard copy)
C. Pederson, DRS (hard copy - IR's only)
DRPIII
DRSIII

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

| | |
|---|---|
| Docket Nos: | 50-254; 50-265 |
| License Nos: | DPR-29; DPR-30 |
| Report No: | 05000254/2004002; 05000265/2004002 |
| Licensee: | Exelon Nuclear |
| Facility: | Quad Cities Nuclear Power Station, Units 1 and 2 |
| Location: | 22710 206th Avenue North<br>Cordova, IL 61242 |
| Dates: | January 1 through March 31, 2004 |
| Inspectors: | K. Stoedter, Senior Resident Inspector<br>M. Kurth, Resident Inspector<br>S. Caudill, Resident Inspector - Duane Arnold<br>J. House, Senior Radiation Specialist<br>D. Jones, Reactor Engineer<br>D. Nelson, Radiation Specialist<br>L. Ramadan, Nuclear Safety Intern<br>R. Ganser, Illinois Emergency Management Agency |
| Approved by: | M. Ring, Chief<br>Branch 1<br>Division of Reactor Projects |

Enclosure

# SUMMARY OF FINDINGS

IR 05000254/2004002, 05000265/2004002; 01/01/2004-03/31/2004; Quad Cities Nuclear Power Station, Units 1 & 2; Event Followup.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on inservice inspection and radiation protection. The inspection was conducted by Region III inspectors and the resident inspectors. One Green finding involving one Non-Cited Violation was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

### Cornerstone: Mitigating Systems

Green. A finding of very low safety significance was self-revealed when a radiation protection technician performing surveys in the Unit 1 drywell discovered that the 3B electromatic relief valve pilot valve vent line was broken off at the pilot valve chamber assembly. The pilot valve vent line broke due to the failure to have standard instructions to identify, evaluate, and resolve issues related to cold spring forces during the installation of small-bore piping. Over time the cold spring forces, taken in conjunction with the increased vibrations caused by the extended power uprate, led to a condition where the electromatic relief valve (an automatic depressurization system valve) would not have operated when called upon. Corrective actions for this issue included informing maintenance personnel of potential cold-spring issues during piping installations, repairing the 3B electromatic relief valve, and inspecting the remaining relief valves for similar degradation.

This finding was more than minor because the inoperability of one of the automatic depressurization system valves impacted the overall operability, availability, and reliability of the automatic depressurization system which can be utilized following a small break loss of coolant accident. This finding was of very low safety significance since operations personnel could have manually depressurized the reactor vessel if needed and all other mitigating systems equipment was available. This finding was determined to be a Non-Cited Violation of Technical Specifications 3.4.3.A and 3.5.1.G due to having an automatic depressurization system valve inoperable for greater than 14 days. (Section 4OA3)

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

No findings of significance were identified.

## REPORT DETAILS

### Summary of Plant Status

Unit 1 began the inspection period with reactor power administratively limited to 85 percent pending the evaluation of extended power uprate vibration data and the affects of these vibrations on plant equipment. Short duration power reductions were conducted on February 22 and March 14 in order to perform turbine valve testing and control rod scram time testing. Unit 1 operated at 85 percent power for the remainder of the inspection period.

Unit 2 began the inspection period operating at 96 percent power. During the month of January, operations personnel performed two planned power reductions to perform control rod pattern adjustments. On February 2, operations personnel reduced reactor power to approximately 55 percent due to a high pressure feedwater heater relief valve actuation. Maintenance personnel replaced the relief valve which allowed operations personnel to return Unit 2 to 96 percent power on February 3. Refueling outage Q2R17 began on February 24. Major activities performed during the outage included replacing the low pressure turbine buckets, chemical decontamination of reactor recirculation system piping, noble metals injection, replacing the power operated relief valves with electromatic relief valves, installing a digital reactor recirculation control system, and installing a new main power transformer. Operations personnel commenced startup activities on March 27. Unit 2 was sychronized to the electrical grid the following day. Approximately two days later, a reactor scram occurred during routine turbine thrust bearing wear detector testing. After completing repairs, the licensee commenced a second reactor startup the evening of March 30. At the end of the report period the licensee was at 70 percent power and continuing with power ascension activities.

## 1. REACTOR SAFETY

### Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope

In early January, Quad Cities Station experienced outside air temperatures below 0 degrees. In preparation for the extreme cold, engineering personnel informed the operations department that the contaminated condensate storage tank heater breakers would likely begin to trip due to internal shorting caused by entrained moisture. The inspectors selected this actual adverse weather condition for additional inspection because if the water in the tank froze, the normal suction source to the high pressure coolant injection, reactor core isolation cooling, and safe shutdown makeup systems would be lost. In addition, safety-related instrumentation inside the tank which ensured that the mitigating systems listed above were supplied by an alternate suction source under low tank level conditions may be lost.

The inspectors reviewed the Updated Final Safety Analysis Report and engineering calculations to determine the actual number of heaters needed to prevent the contaminated condensate storage tanks from freezing. The licensee's cold weather procedures were reviewed to determine if the tank heater breakers were inspected on a periodic basis. The inspectors interviewed operations and engineering personnel to determine the tank heater breakers equipment history, the actions taken previously to prevent the breakers from tripping, and to become familiar with the temporary modifications installed to ensure that the required number of tank heaters remained energized. Lastly, the inspectors reviewed several condition reports associated with the breaker trips.

b. Findings

No findings of significance were identified. However, problem identification and resolution observations associated with this issue can be found in Section 4OA2 of this report.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

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

- Unit 1 High Pressure Coolant Injection;
- Unit 2 Core Spray;
- Unit 2 Fuel Pool Cooling; and
- Unit 2 Reactor Building Closed Cooling Water.

The inspectors utilized the valve and breaker checklists listed at the end of this report to verify that the components were properly positioned and that support systems were aligned as required. The inspectors examined the material condition of the components and observed equipment operating parameters to verify that there were no obvious deficiencies. The inspectors reviewed outstanding work orders and condition reports associated with each system to verify that those documents did not reveal issues that could affect the equipment inspected. The inspectors compared the information in the appropriate sections of the Updated Final Safety Analysis Report to actual equipment performance data to determine that the system was capable of performing its design function. Lastly, the inspectors reviewed Condition Reports 205146, 205514, 205862, 205892, 205902, 205908, 205910, and 206471 which were initiated during the inspection to ensure that the inspectors' observations were adequately documented and that appropriate corrective actions were implemented.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Zone Walkdowns

a. Inspection Scope

The inspectors performed routine walkdowns of accessible portions of the following risk significance fire zones:

- Fire Zone 1.1.1.6 - Refuel Floor;
- Fire Zone 1.2.2 - Unit 2 Drywell;
- Fire Zone 8.2.6.D - Unit 2 Low Pressure Heater Bay;
- Fire Zone 8.2.6.E - Unit 2 High Pressure Heater Bay;
- Fire Zone 8.2.7.D - Unit 2 Low Pressure Heater Bay West;
- Fire Zone 8.2.8.A - Unit 1 Switchgear Area; and
- Fire Zone 8.2.8.E - Unit 2 Turbine Deck.

During a walkdown of each fire zone, the inspectors verified that transient combustibles were controlled in accordance with the licensee's procedures and observed the physical condition of fire suppression devices. The inspectors verified the condition and placement of fire extinguishers and hoses against the Pre-Fire Plan fire zone maps. The physical condition of accessible passive fire protection features such as fire doors, fire dampers, fire barriers, fire zone penetration seals, and fire retardant structural steel coatings were also inspected to verify proper installation and physical condition.

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation

a. Inspection Scope

The inspectors observed the fire brigade participate in fire drills on January 28 and February 3. The simulated fires occurred on the turbine deck within one of the reactor recirculation motor generator sets. These fire drills were chosen because the fire hazard location was adjacent to safety-related switchgear needed to safely shut down the plant during certain fire scenarios. The inspectors observed that protective clothing was properly donned; self-contained breathing apparatus equipment was properly worn and used; fire hose lines were capable of reaching the necessary fire hazard locations; the fire area was entered in a controlled manner; sufficient fire fighting equipment was brought to the scene; the fire brigade leader's fire fighting directions were thorough, clear, and effective; fire fighting pre-planned strategies were utilized; the licensee's pre-planned drill scenario was followed, and the drill objectives acceptance criteria were met. The inspectors also reviewed Condition Report 204252 which was written to document weaknesses identified by the licensee during the first quarter 2004 fire drills.

b. Findings

No findings of significance were identified.

1R07 Heat Sink (71111.07A)

a. Inspection Scope

On February 10, the inspectors observed engineering and operations personnel complete performance testing on the 2A residual heat removal heat exchanger. This heat exchanger was chosen for inspection due to its high safety significance and risk significance. During the testing observation the inspectors verified that the acceptance criteria and test results considered differences between test and design basis conditions because testing at the design heat removal rate was not practical. The inspectors also performed independent calculations using the licensee's test results to confirm that the results considered possible uncertainties and that the heat exchanger remained capable of performing its safety function.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors conducted a review of the implementation of the licensee's inservice inspection program for monitoring degradation of the Unit 2 (Q2R17 Outage) reactor coolant system boundary and the risk significant piping system boundaries.

Specifically, the inspectors conducted a (onsite or record) review of the following five nondestructive examination activities to evaluate compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and to verify that indications and defects were dispositioned in accordance with the ASME Code: (This review counted as two samples.)

- Ultrasonic examination of reactor core isolation cooling system elbow to pipe weld IRI-1002-16;
- Ultrasonic examination of feedwater system pipe to elbow weld 1FW-1001-68;
- Ultrasonic examination of residual heat removal system pipe to elbow weld 1RH-1004-24;
- Magnetic particle examination of residual heat removal heat exchanger shell to saddle fillet weld N6A-F1; and
- Magnetic particle examination of residual heat removal heat exchanger shell to nozzle fillet weld N6A-F2.

The inspectors also reviewed the following examination from the previous outage (Q1R17) with recordable indications that has been accepted by the licensee for continued service to verify that the licensee's acceptance for continued service was in accordance with the ASME Code: (This review counted as one sample.)

- Recordable indications found during visual examination of jet pumps #2 and #7 AD-3b welds.

The inspectors reviewed pressure boundary welds for Class 1 or 2 systems which were completed since the beginning of the previous refueling outage, to verify that the welding acceptance (e.g., radiography) and pre-service examinations were performed in accordance with ASME Code requirements: (This review could not be counted as a sample.)

- This review found that no pressure boundary welds for Class 1 or 2 systems were completed since the beginning of the previous refueling outage.

The inspectors reviewed one ASME Section XI Code repair or replacement to verify the repair and replacement met ASME Code requirements. (This review counted as one sample.)

- Main steam system ASME Section XI, 1989 Edition, Code Class 1 snubber replacement and addition of new welds (W.O. 99242365-22).

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

b. <u>Findings</u>

No findings of significance were identified.

1R13 <u>Maintenance Risk and Emergent Work</u> (71111.13)

a. <u>Inspection Scope</u>

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

- Work Week January 26 through 31, including planned maintenance or suveillance testing on the Unit 1 emergency diesel generator, the Unit 1 reactor core isolation cooling system, and emergent work on the Unit 2 essential service bus uninterruptable power supply;
- Work Week February 9 through 14, including planned maintenance on the 1A and 1B residual heat removal service water pumps, the 1A and 1B residual heat removal pumps, the Unit 1 station blackout diesel generator, and emergent work on a Unit 2 residual heat removal service water pump;
- Work Week February 16 through 21, including planned maintenance on the 2A control rod drive pump, the 2B electrohydraulic control pump, the 2A stator water cooling pump, and one of the Unit 2 bus duct blowers;
- Work Week February 23 through 28, including planned maintenance on bus 23, bus 24, bus 24-1, bus 25, bus 27, bus 29, motor control center 29-2, the 1/2A standby gas treatment system, the Unit 2 emergency diesel generator, the Unit 2 250 Vdc battery, and Unit 2 250 Vdc bus 2A; and
- Work Week March 8 through March 13, including planned maintenance on bus 23, bus 23-1, the ½ emergency diesel generator, the ½A standby gas treatment system, and various breakers.

b. Findings

No findings of significance were identified.

1R14 Non-Routine Evolutions (71111.14)

.1 Failure of High Pressure Feedwater Heater Relief Valve

a. Inspection Scope

During the week of February 2, the inspectors reviewed Technical Specifications, procedures, control room log entries, maintenance work orders, condition reports, and interviewed licensee personnel to determine the circumstances that led to the failure of a high pressure feedwater heater relief valve and a corresponding power reduction. The results of this review were used to verify that operations personnel had responded to the relief valve failure as required by procedures. The inspectors also reviewed several condition reports previously written on the feedwater heater relief valves to ensure that the failure was not a repeat condition and that prior corrective actions were appropriate to the circumstance.

b. Findings

No findings of significance were identified.

.2 Unit 2 Reactor Scram During Turbine Valve Testing

a. Inspection Scope

The inspectors observed operator performance in coping with the Unit 2 turbine trip and subsequent reactor scram while conducting turbine testing on March 30, 2004. In particular, operators were testing the turbine thrust bearing wear detector when the turbine trip occurred. The inspectors reviewed operator logs and plant computer data. Also, the inspectors evaluated the operators' response to ensure it was in accordance with station procedures and training.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

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

- Condition Report 179235, Potentially Nonconservative Pressure Temperature Curves;
- Condition Report 148103, Nonconforming Moore Industries SCT Signal Converter/Isolator;
- Condition Report 191530, 125 Volt DC Grounds Identified on Power Operated Relief Valves 2-0203-3B and 2-0203-3E;
- Condition Report 131936, Missing Belleville Washer in 1-0203-2C Main Steam Isolation Valve;
- Condition Report 132397, Manufacturing Deficiency in Agastat Model ETR Relays;
- Condition Reports 205862 and 205892, Wrong Oil in the 2A and 2B Core Spray Pump Motors; and
- Condition Report 200772, Main Steam Safety Valves May Not Have Met Technical Specification Requirements.

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

During the review of a Technical Specification amendment request for Dresden Station, the Office of Nuclear Reactor Regulation identified a concern regarding the ability of the main steam safety valves to meet Technical Specification Surveillance Requirement 3.4.3.1. Technical Specification Surveillance Requirement 3.4.3.1 required the licensee to demonstrate that the main steam safety valves lifted within plus or minus one percent of the setpoint assumed in the reactor overpressure analysis and the anticipated transient without scram overpressure analysis.

Quad Cities engineering personnel reviewed the NRC's concern and identified that a similar condition existed at the station. A review of historical as-found main steam safety valve testing results determined that some of the valves operated outside of the one percent tolerance specified in the Technical Specifications. As a result, the licensee may not have been able to ensure that a reactor vessel overpressure condition would not have occurred under certain conditions.

The inspectors reviewed the licensee's overpressure analyses and discussed this issue with regulatory assurance, operations, and engineering personnel. During the review and discussions, the inspectors learned that both of the analyses assumed that Unit 1 and Unit 2 were operating at full thermal power. In addition, the analyses assumed that one of the safety relief valves was inoperable. At the time this issue was identified, neither unit was operating at full thermal power and all of the safety relief valves were operable. Based upon this information, the inspectors concluded that this issue was not an immediate safety concern. However, Unit 1 had operated at full thermal power levels during the summer of 2003. In addition, one of the safety relief valves may have been inoperable during this time (see Section 1R20 of Inspection Report 05000254/03-13; 05000265/03-13). As a result, additional information was needed to determine whether the licensee had been in violation of their Technical Specifications and/or outside their design and licensing basis.

At the conclusion of the inspection, the licensee was conducting reviews to determine whether the reactor vessel was adequately protected from an overpressure condition even though some of the main steam safety valves would not have operated within the one percent tolerance allowed by the Technical Specifications. The licensee planned to use the results of the review to determine whether additional actions, such as the submittal of a Technical Specification amendment request or a Licensee Event Report, were required. The inspectors considered this item to be unresolved pending an inspection of the licensee's review **(URI 05000254/2004002-01; 05000265/2004002-01)**.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

During the inspection period, the inspectors reviewed the following permanent plant modifications:

- Engineering Change 342429, Add Safe Shutdown Makeup Pump Heating, Ventilation, and Air Conditioning Room Cooler Trouble Indications and Reset Pushbutton, Revision 0;

- Engineering Change 22082, Unit 2 Reactor Recirculation Control System and Jet Pump Instrumentation Digital Upgrade, Various Revisions;
- Engineering Change 333573, Permanent Lead Shielding Around Recirculation Risers in Unit 2 Drywell, Revision 0; and
- Engineering Change 343933, Replace Unit 2 Power Operated Relief Valves with Electromatic Relief Valves, Various Revisions.

The inspectors reviewed the design adequacy of the modifications by verifying one or more of 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 finding of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Work Order 99174178-08, Replace Portion of Unit 2 High Pressure Coolant Injection Steam Line Drain Piping;
- Work Request 135845, Troubleshoot and Repair ½ Emergency Diesel Generator Fuel Oil Transfer Pump Level Switch Failure to Actuate;
- Work Order 518491–01, Mechanical Maintenance Diesel Fire Pump “A” Annual Inspection;

- Work Order 480358-01, 250 VDC Battery Performance Test; and
- Work Order 645432-01, Replace/Weld Buildup of High Pressure Discharge Flange of 2-1001-65B Residual Heat Removal Service Water Pump Discharge Elbow.

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 post maintenance test activity adequately tested the safety function(s) affected by the maintenance, that acceptance criteria were consistent with licensing and design basis information, and that the procedure was properly reviewed and approved. When possible, the inspectors observed the post maintenance testing activity and verified that the structure, system, or component operated as expected; test equipment used was within its required range and accuracy; jumpers and lifted leads were appropriately controlled; test results were accurate, complete, and valid; test equipment was removed after testing; and any problems identified during testing were appropriately documented.

b. <u>Findings</u>

No findings of significance were identified.

1R20 <u>Refueling and Outage Activities</u> (71111.20)

a. <u>Inspection Scope</u>

The inspectors reviewed the licensee's outage schedule, verified equipment alignments, and observed control room and outage activities. The inspectors verified that the licensee effectively conducted the shutdown, managed elements of risk pertaining to reactivity control during and after the shutdown, and implemented decay heat removal system procedure requirements as applicable.

The inspectors performed the following activities daily:

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

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

- shutdown and cooldown to a cold shutdown condition (MODE 4);

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

b. Findings

On February 24, Unit 2 was shutdown for a scheduled refueling outage. The scope of the refueling outage included inspections of the steam dryer in accordance with recommendations described in General Electric Service Information Letter 644, Supplement 1. The inspections performed during the refueling outage identified cracking on areas of the steam dryer that were previously modified to address the impacts of the extended power uprate and the June 2003 Unit 2 steam dryer failure.

Due to the presence of ongoing cracking, the licensee developed a plan to attempt to identify the mechanism that has been causing the unacceptable steam dryer loads. Details of this plan were discussed with the NRC during conference calls on March 8, 18, 26, and 30, 2004. Additional details were provided by the licensee to the NRC via letter dated April 2, 2004. Within the April 2 letter, the licensee committed to the NRC to limit operation of Quad Cities Units 1 and 2 to the maximum original licensed power level of 2511 megawatts thermal. The units may operate for brief periods above 2511 megawatts thermal for the purposes of data gathering. However, these periods may not exceed a total of 72 hours for each unit.

At the conclusion of the inspection period, licensee evaluations were ongoing to justify continuous operation of Quad Cities Units 1 and 2 at extended power uprate power levels. The licensee planned to provide the NRC with information such as the plans for monitoring steam dryer performance and other potentially affected components at extended power uprate power levels, the criteria for prompt corrective action in response to performance degradation, a description of the loads on the steam dryer, identification of the most susceptible equipment failure locations, an evaluation of the current Unit 2 steam dryer repairs, the results of the independent review team looking at the steam dryer and other extended power uprate issues, the results of the flow induced vibration reviews, and the future dryer inspection plans. The NRC review of the licensee's justification for continuous operation of Quad Cities Units 1 and 2 at extended power uprate power levels is an Unresolved Item **(URI 05000254/2004002-02; 05000265/2004002-02)**.

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 6500-10, Functional Test of Unit 2 Second Level Undervoltage, Revision 13;
- QCOS 6600-43, Unit ½ Diesel Generator Load Test, Revision 17;
- QCTS 0600-05, Main Steam Isolation Valve Local Leak Rate Test, Revision 11;
- QCMMS 4100-32, ½ A-4101 Diesel Driven Fire Pump Annual Capacity Test, Revision 15;
- QCOS 6700-02, MCC 28/29-5 Auto-Transfer Logic Operability Surveillance, Revision 8;
- QCTS 0240-07, Unit 2 250 VDC Safety Related Battery Testing, Revision 0; and
- QCOS 1600-32, Drywell/Torus Closeout, Revision 10.

The inspectors verified that the structures, systems, and components tested were capable of performing their intended safety function by comparing the surveillance procedure or calibration acceptance criteria and results to design basis information contained in Technical Specifications, the Updated Final Safety Analysis Report, and licensee procedures. The inspectors verified that each test or calibration was performed as written, the data was complete and met requirements, and the test equipment range and accuracy were consistent with the application by observing the performance of the activity. Following work completion, the inspectors conducted walkdowns of the associated areas to verify that test equipment had been removed and that the system or component was returned to its normal standby configuration. The inspectors also reviewed multiple condition reports which were generated during the inspection to ensure that these issues were entered into the licensee's corrective action program.

b. <u>Findings</u>

No findings of significance were identified.

1R23 <u>Temporary Modifications</u> (71111.23)

a. <u>Inspection Scope</u>

The inspectors reviewed documentation for the following temporary configuration change:

- Engineering Change 345750, Use Service Water to Pressurize Residual Heat Removal Service Water at the 2A Residual Heat Removal Heat Exchanger to Diminish Internal Leakage, dated January 8, 2004.

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

b. Findings

No findings of significance were identified.

## 2. RADIATION SAFETY

**Cornerstone: Occupational Radiation Safety**

2OS1 Access Control to Radiologically Significant Areas (71121.01)

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

a. Inspection Scope

The inspectors discussed performance indicators (PIs) with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone to review. There were none. This represented one sample.

b. Findings

No findings of significance were identified.

.2 Plant Walkdowns and Radiation Work Permit Reviews

a. Inspection Scope

The inspectors identified three radiologically significant work areas within radiation areas, high radiation areas, and airborne radioactivity areas in the plant. Work packages, which included associated licensee controls and surveys of these areas, were reviewed to determine if radiological controls including surveys, postings, and barricades were acceptable. This represented one sample. These work areas were walked down and surveyed (using an NRC survey meter) to verify that the prescribed radiation work permit, procedures, and engineering controls were in place, that licensee surveys and postings were complete and accurate, and that air samplers were properly located. These areas included but were not limited to:

- Turbine Sandblasting;
- Residual Heat Removal Heat Exchanger, Leakage Repair; and
- U2 Reactor Disassembly/Reassembly/Cavity Work.

This represented one sample.

The inspectors reviewed the radiation work permits and work packages used to access these and other high radiation work areas to identify the work control instructions and control barriers that had been specified. Technical specification high radiation area and locked high radiation area requirements were used as standards for the necessary barriers. Electronic dosimeter alarm set points for both integrated dose and dose rate were evaluated for conformity with survey indications and plant policy. Workers were interviewed to verify that they were aware of the actions required when their electronic dosimeters noticeably malfunctioned or alarmed. This represented one sample.

The inspectors reviewed the available radiation work permits for airborne radioactivity areas to determine if there was a potential for individual worker internal exposures of >50 millirem committed effective dose equivalent. Barrier integrity and engineering controls performance such as high efficiency particulate (HEPA) filtration ventilation system operation were evaluated. Work areas having a history of, or the potential for, airborne transuranics were evaluated to verify that the licensee had considered the potential for transuranic isotopes and provided appropriate worker protection. This represented one sample. The adequacy of the licensee's internal dose assessment process for internal exposures >50 millirem committed effective dose equivalent was assessed for adequacy. This represented one sample.

b. Findings

No findings of significance were identified.

.3 Problem Identification and Resolution

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, licensee event reports, and special reports related to the access control program to verify that identified problems were entered into the corrective action program for resolution. This represented one sample. Corrective action reports related to access controls and any available high radiation area radiological incidents (non-performance indicators identified by the licensee in high radiation areas <1Rem/hr) were reviewed. Staff members were interviewed and corrective action documents were reviewed to verify that follow-up activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk based on the following:

- Initial problem identification, characterization, and tracking;
- Disposition of operability/reportability issues;
- Evaluation of safety significance/risk and priority for resolution;
- Identification of repetitive problems;
- Identification of contributing causes;
- Identification and implementation of effective corrective actions;
- Resolution of Non-Cited Violations tracked in the corrective action system; and
- Implementation/consideration of risk significant operational experience feedback.

This represented one sample.

The inspectors evaluated the licensee’s process for problem identification, characterization, prioritization, and verified that problems were entered into the corrective action program and resolved. For repetitive deficiencies and/or significant individual deficiencies identified in the problem identification and resolution process, the inspectors verified that the licensee’s self-assessment activities were capable of identifying and addressing these deficiencies. This represented one sample.

The inspectors discussed performance indicators with the radiation protection staff and reviewed data from the licensee's corrective action program to determine if there were any performance indicators for the occupational exposure cornerstone to review. There were none. This represented one sample.

b. Findings

No findings of significance were identified.

.4 Job-In-Progress Reviews

a. Inspection Scope

The inspectors selected three jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas for observation of work activities that presented the greatest radiological risk to workers. This involved work that was estimated to result in the highest collective doses, and included diving activities in the spent fuel pool, and other work areas where radiological gradients were present.

The inspectors reviewed radiological job requirements including radiation work permit requirements and work procedure requirements, and attended as-low-as-is-reasonably-achievable (ALARA) job briefings. Job performance was observed with respect to these requirements to verify that radiological conditions in the work area were adequately communicated to workers through pre-job briefings and postings. This represented one sample. The inspectors also verified the adequacy of radiological controls including required radiation, contamination, and airborne surveys for system breaches; radiation protection job coverage which included audio and visual surveillance for remote job coverage, and contamination controls. This represented one sample.

Work in high radiation areas having significant dose rate gradients was reviewed to evaluate the application of dosimetry to effectively monitor exposure to personnel, and to verify that licensee controls were adequate. These work areas involved dose rate gradients that could be severe (diving activities and the residual heat removal heat exchanger area) which increased the necessity of providing multiple dosimeters and/or enhanced job controls. This represented one sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the licensee's performance indicators for high risk, high dose rate and high radiation areas, and for all very high radiation areas to verify that workers were adequately protected from radiological overexposure. Discussions were held with the Radiation Protection Manager concerning high dose rate/high radiation area and very high radiation area controls and procedures, including procedural changes that had occurred since the last inspection, in order to verify that any procedure modifications did not substantially reduce the effectiveness and level of worker protection. This represented one sample. During plant walkdowns, the posting and locking of entrances to high dose rate high radiation areas, and very high radiation areas were reviewed for adequacy. This represented one sample.

b. Findings

No findings of significance were identified

.6 Radiation Worker Performance

a. Inspection Scope

During job performance observations, the inspectors evaluated radiation worker performance with respect to stated radiation protection work requirements and evaluated whether workers were aware of the significant radiological conditions in their workplace, the radiation work permit controls and limits in place, and that their performance had accounted for the level of radiological hazards present. This represented one sample.

Radiological problem reports, which found that the cause of an event resulted from radiation worker errors, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. These problems, along with planned and taken corrective actions were discussed with the Radiation Protection Manager. This represented one sample.

b. Findings

No findings of significance were identified.

.7 Radiation Protection Technician Proficiency

a. Inspection Scope

The inspectors observed and evaluated radiation protection technician performance with respect to radiation protection work requirements. This was done to evaluate whether radiation protection technicians were aware of the radiological conditions in their workplace, the radiation work permit controls and limits were in place, and if their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities. This represented one sample.

Radiological problem reports, which found that the cause of an event was radiation protection technician error, were reviewed to determine if there was an observable pattern traceable to a similar cause, and to determine if this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. This represented one sample.

b. Findings

No findings of significance were identified.

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

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed plant collective exposure history, current exposure trends along with ongoing and planned activities in order to assess current performance and exposure challenges. This included determining the plant's current 3-year rolling average collective exposure in order to help establish resource allocation and to provide a perspective of significance for any resulting inspection finding assessment. This represented one sample.

The inspectors reviewed the outage work scheduled during the inspection period along with associated work activity exposure estimates including the five work activities which were likely to result in the highest personnel collective exposures. Site specific trends in collective exposures and source-term measurements were reviewed. This represented one sample. Procedures associated with maintaining occupational exposures ALARA, and processes used to estimate and track work activity specific exposures were reviewed. This represented one sample.

b. Findings

No findings of significance were identified.

.2 Radiological Work Planning.

a. Inspection Scope

The inspectors evaluated the licensee's list of work activities ranked by estimated exposure that were in progress and selected the three work activities of highest exposure significance.

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

The inspectors compared the results achieved including dose rate reductions and person-rem used with the intended dose established in the licensee's ALARA planning for these work activities. Reasons for inconsistencies between intended and actual work activity doses were evaluated. The interfaces between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups were evaluated to identify interface problems or missing program elements. The integration of ALARA requirements into work procedure and RWP documents was evaluated to verify that the licensee's radiological job planning would reduce dose.

The inspectors compared the person-hour estimates, provided by maintenance planning and other groups to the radiation protection group, with the actual work activity time requirements in order to evaluate the accuracy of these time estimates. Shielding requests from the radiation protection group were evaluated with respect to dose rate reduction along with engineering shielding responses follow up. The inspectors verified that work activity planning included consideration of the benefits of dose rate reduction activities such as shielding provided by water filled components/piping, job scheduling, along with shielding and scaffolding installation and removal activities. The licensee's post-job (work activity) reviews were evaluated to verify that identified problems were entered into the licensee's corrective action program.

b. Findings

No findings of significance were identified.

.3 Verification of Dose Estimates and Exposure Tracking Systems

a. Inspection Scope

The inspectors reviewed the assumptions and bases for the current annual collective exposure estimate. Procedures were reviewed in order to evaluate the licensee's methodology for estimating work activity-specific exposures and the intended dose outcome. Dose rate and man-hour estimates were evaluated for reasonable accuracy. This represented one sample.

The licensee's process for adjusting exposure estimates or re-planning work, when unexpected changes in scope, emergent work or higher than anticipated radiation levels were encountered, was evaluated. This included determining that adjustments to estimated exposure (intended dose) were based on sound radiation protection and ALARA principles and not adjusted to account for failures to control the work. The frequency of these adjustments was reviewed to evaluate the adequacy of the original ALARA planning process. This represented one sample.

b. Findings

No findings of significance were identified.

.4 Job Site Inspections and As Low As Is Reasonably Achievable (ALARA) Control

a. Inspection Scope

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

- The licensee's use of engineering controls to achieve dose reductions was evaluated to verify that procedures and controls were consistent with the licensee's ALARA reviews, that sufficient shielding of radiation sources was provided for and that the dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.
- Job sites were observed to determine if workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA by moving to the low dose waiting area when subjected to temporary work delays.
- The inspectors attended work briefings and observed ongoing work activities to determine if workers received appropriate on-the-job supervision to ensure the ALARA requirements were met. This included verification that the first-line job supervisor ensured that the work activity was conducted in a dose efficient manner by minimizing work crew size, ensuring that workers were properly trained, and that proper tools and equipment were available when the job started.

b. Findings

No findings of significance were identified.

.5 Source-Term Reduction and Control

a. Inspection Scope

The inspectors reviewed licensee records to determine the historical trends and current status of tracked plant source terms and determined that the licensee was making allowances and had developed contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry. This represented one sample.

The inspectors verified that the licensee had developed an understanding of the plant source-term, which included knowledge of input mechanisms in order to reduce the source term. The licensee's source-term control strategy was evaluated. This included a cobalt reduction strategy and shutdown ramping and operating chemistry plan which was designed to minimize the source-term external to the core. Other methods used by the licensee to control the source term, including component/system decontamination and the use of shielding, were evaluated. This represented one sample.

The licensee's process for identification of specific sources was reviewed along with exposure reduction actions and the priorities the licensee had established for implementation of those actions. The results that had been achieved against these priorities since the last refueling cycle were reviewed. For the current assessment period, source reduction evaluations were verified along with actions taken to reduce the overall source-term compared to the previous year. This represented one sample.

b. Findings

No findings of significance were identified.

.6 Radiation Worker Performance

a. Inspection Scope

Radiation worker and radiation protection technician performance was observed during work activities being performed in radiation areas, airborne radioactivity areas, and high radiation areas that presented the greatest radiological risk to workers. The inspectors evaluated whether workers demonstrated the ALARA philosophy in practice by being familiar with the work activity scope and tools to be used, by utilizing ALARA low dose waiting areas and that work activity controls were being complied with. Also, radiation worker training and skill levels were reviewed to determine if they were sufficient relative to the radiological hazards and the work involved. This represented one sample.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

**Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity,**

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's performance indicator submittals for the periods listed below. The inspectors used the performance indicator definitions and guidance contained in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," to verify the accuracy of the performance indicator data. The following eight performance indicators were reviewed:

Unit 1

- Unplanned Scrams per 7000 Hours;
- Scrams With the Loss of Normal Heat Removal;
- Reactor Coolant System Leak Rate;
- System Unavailability - Residual Heat Removal System

Unit 2

- Unplanned Scrams per 7000 Hours;
- Scrams With the Loss of Normal Heat Removal;
- Reactor Coolant System Leak Rate;
- System Unavailability - Residual Heat Removal System

The inspectors reviewed selected applicable conditions and data from logs, licensee event reports, monthly operating reports, inspection reports, licensee event reports, and condition reports from January 2003 through December 2003 for each performance indicator specified above to identify conditions which may have impacted the specific performance indicator. The inspectors independently re-performed calculations where applicable. The inspectors compared that information to the information reported for each performance indicator to ensure that the licensee reported the data accurately.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

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. Minor issues entered into the licensee's corrective action system as a result of inspectors' observations are listed within the individual sections of this report and are included in the list of documents reviewed which is attached to this report.

.2 Review of Specific Problem Identification and Resolution Issues

a. Inspection Scope

During the inspection period, the inspectors assessed the licensee's ability to identify and resolve conditions adverse to quality by direct observation of activities as part of the baseline inspection program, performing daily reviews of condition reports, attending the management review committee meetings which discussed previously identified problems and proposed corrective actions, interviewing personnel, and attending meetings on specific subjects. The inspectors selected the following three samples for additional review:

- repeated tripping of the contaminated condensate storage tank heaters;
- decreasing Unit 1 reactor bottom head drain temperature; and
- inadvertent isolation of the residual heat removal system while in shutdown cooling.

b. Issues

The inspectors determined that the licensee appropriately identified problems. However there were several examples where individuals were presented with problems, but failed to perform a more comprehensive review of the issue prior to taking actions. This resulted in the inoperability of adverse weather-related equipment, the communication of incorrect information to the operations department, and the inadvertent isolation of an operating safety system. The inspectors noted that the licensee initiated condition reports for each of the self-revealing issues listed above. Once the condition reports were initiated, the licensee's formal evaluation of the problem was thorough and identified appropriate corrective actions.

Repeated Tripping of Tank Heaters

In August 1999, the licensee identified that the number of contaminated condensate storage tank heaters in service may not have been adequate to prevent the contents of the tank from freezing during adverse weather conditions. The inspectors reviewed this issue since freezing of the contaminated condensate storage tanks could have led to a situation which rendered all three high pressure injection sources unavailable or inoperable. Through this review, the inspectors determined that eight heaters were needed to prevent the tanks from freezing. Although previous corrective actions for the degraded heaters had been delayed multiple times in the early 1990's, the licensee subsequently took action to ensure that eight heaters per tank were functional. These actions included replacing some of the heaters (see Inspection Reports 50-254/99020; 50-265/99020 and 50-254/99025; 50-265/99025).

In January 2003, the licensee discovered that the breaker for the contaminated condensate storage tank A heating element was tripped. A followup review determined that the feeder breaker for the motor control centers which supplied power to the contaminated condensate storage tank heaters was overloaded. This was subsequently corrected. In addition, the licensee worked with the heater vendor and discovered that additional heater trips were being caused by moisture intrusion internal to the heater circuitry and due to the age of the heaters. The vendor recommended that the licensee implement actions to periodically energize the heaters in order to eliminate the moisture internal to the heater circuitry. Based upon this information, engineering began working on a modification to energize the heaters. In the interim, operations personnel conducted routine inspections of the motor control centers when outside air temperatures fell below 5 degrees Fahrenheit in January 2004 to ensure the heaters remained energized.

On January 6, 2004, Quad Cities Station experienced extremely cold outside air temperatures. Once again, some of the contaminated condensate storage tank heater breakers began to trip. Over the next two weeks, operations personnel increased their routine monitoring of the motor control centers to once per hour. More often than not, the operators were identifying that the motor control center breakers supplying power to the contaminated condensate storage tank heaters were tripped. Additional monitoring was implemented and determined that some of the contaminated condensate storage tank heater breakers were only remaining closed approximately 10 to 15 minutes out of every hour. Although heater performance was worse than expected, the licensee's corrective actions focused on increased monitoring of the motor control centers and several emergent modifications to keep the breakers from tripping rather than performing an in-depth look at the heater circuitry in an attempt to maximize the number of heaters that could remain operable.

Approximately one month later, operations personnel reviewed procedure QCOP 0010-02, "Required Cold Weather Routines," and discovered that operability of the contaminated condensate storage tank heaters was based upon meeting the eight heater continuous capability curve included in the procedure (see Condition Report 198447). Due to the frequent breaker trips, operations personnel determined that the eight heater continuous capability curve could not be used since eight heaters were not continuously in service. Operations personnel then tasked the engineering department to develop a method for maintaining at least eight heaters in service within 36 hours. Engineering personnel developed and implemented an additional temporary modification which consisted of lifting a minimal number of leads to ensure that at least eight heaters remained functional. The need for this modification was not recognized earlier since engineering believed that the heaters would dry out and heater performance would improve the longer the heaters remained energized.

The inspectors reviewed previous corrective actions documents, work requests, modification information, increased monitoring information, and interviewed operations and engineering personnel and had the following concerns:

- the amount of time that elapsed before discovering the inability to meet the eight heater continuous capability curve was excessive. For example, more than one month was needed to make this determination even though the procedure was a continuous use procedure which was used any time outside air temperatures dropped below 5 degrees;

- implementation of information obtained following the 1999 contaminated condensate storage tank heater issue could have reduced the burden placed on operations personnel during the increased monitoring inspections. In addition, less time could have been spent designing and installing emergent modifications which placed the plant at an increased risk during the time the tank heater breakers were tripping. As part of the followup for the 1999 contaminated condensate storage tank heater event engineering personnel developed information which clearly stated the actual number of contaminated condensate storage tank heaters that were needed under specific temperatures and wind speeds to ensure that the contaminated condensate storage tanks would not freeze. Although this information was available within engineering, it was not provided to the operations department nor was it placed in the required cold weather routines procedure.

- operations personnel had not utilized the appropriate program for ensuring that the contaminated condensate storage tank heaters remained functional. As stated above, operations personnel were performing hourly checks of the tank heater breakers under the increased monitoring program. The purpose of the increased monitoring program was to outline additional items that may require increased monitoring as deemed necessary by the shift manager or unit supervisor. However, the inspectors determined that the operations department's hourly checks were being performed to ensure that the freeze protection (as described in the Updated Safety Analysis Report) remained operable. As a result, the hourly contaminated condensate storage tank heater breaker checks should have been considered a compensatory measure and evaluated as part of the licensee's operability determination program. The inspectors determined that viewing the hourly checks as a compensatory measure was not considered because the increased monitoring program procedure was silent regarding the possibility that the increased monitoring of a component may actually be a compensatory measure needed to ensure continued operability. The licensee initiated Condition Report 200169 to document the inspectors observation.

At the conclusion of the inspection period, engineering personnel had provided the operations department with a chart which showed the specific number of contaminated condensate storage tank heaters required under cold weather conditions. The operations department subsequently revised the cold weather routine procedure to include this information. Changes to the increased monitoring procedures were under consideration. Lastly, the licensee was considering replacing multiple contaminated condensate storage tank heaters in the future. No violations of NRC requirements were identified during this review since the contaminated condensate storage tank heaters were non safety-related.

<u>Decreasing Unit 1 Reactor Vessel Bottom Head Drain Temperature</u>

On January 8, operations personnel initiated Condition Report 194035 after identifying that the Unit 1 reactor vessel bottom head drain temperature, as displayed on the control room recorder, had trended down 67 degrees since December 30. The inspectors chose this sample for additional review since an accurate indication of reactor vessel bottom head drain temperature was needed to ensure that thermal shock did not occur prior to starting a reactor recirculation pump. In addition, the loss of the reactor vessel bottom head drain temperature indication would result in the licensee having to shut down the plant if a reactor recirculation pump trip were to occur.

The following day a plant engineering supervisor performed the supervisory review for Condition Report 194035. The supervisor noted that on December 30, the reactor vessel bottom head drain temperature was 422 degrees Fahrenheit. The supervisor reviewed plant drawings and identified several computer points which were also available from the control room recorder. The supervisor performed a word search on the computer points and identified one point which he believed depicted the reactor vessel bottom head drain temperature. The supervisor accessed the computer point information and found that the point was reading approximately 405 degrees Fahrenheit. Since the computer point reading was relatively close to the bottom head drain reading obtained on December 30, the supervisor assumed that the computer point he viewed was indicating actual bottom head drain temperature and that the observed decrease in bottom head drain temperature as seen on the recorder was due to a recorder problem. Work Request 127101 was written to troubleshoot and repair the recorder. In addition, a trend graph which used the information provided by the computer point was set up for use by operations such that a reactor recirculation pump could be immediately restarted if it tripped. Subsequent discussions between engineering and operations also convinced operations personnel that the problem was with the control room recorder. As a result, little emphasis was placed on resolving this condition.

On January 15, an instrument maintenance supervisor was reviewing Work Request 127101 and contacted the plant engineering supervisor for additional information. Through these discussions the supervisors determined that the computer point feeding the trend graph in the control room was for reactor vessel bottom head temperature rather than reactor vessel bottom head drain temperature. Based upon this information, the plant engineering supervisor concluded that if a reactor recirculation pump had tripped, and operations personnel used the trend graph to verify that plant conditions were acceptable for restarting the pump, the Technical Specifications would have been inadvertently violated. Operations personnel were immediately notified of this condition and actions were implemented to ensure that the Technical Specifications were not violated. The engineering supervisor initiated Condition Report 195352 to document his error. Corrective actions were in progress at the conclusion of the inspection period. No violations of NRC requirements were identified since a reactor recirculation pump was not started using inappropriate temperature information.

<u>Inadvertent Isolation of Shutdown Cooling</u>

On February 25, operations personnel performed procedure QCOP 1000-43. This procedure provided instructions for installing two jumpers on a relay in order to prevent the isolation of the residual heat removal system due to high reactor pressure while the system was operating in the shutdown cooling mode. A note contained in the daily work schedule indicated that the performance of QCOP 1000-43 could result in a loss of shutdown cooling.

After receiving a pre-job briefing, an operator and a senior reactor operator obtained two clip-on type jumpers for installation as directed by QCOP 1000-43. While attempting to install the first jumper, the operator identified that the jumper would not stay attached to the screw head located directly above relay contact #1. The operator informed the senior reactor operator about the difficulty encountered when trying to place the jumper. The operators discussed the situation and then identified another location on the relay which was electrically equivalent to installing the jumper on the screw head. As the first jumper was being installed, the operator made contact with the actual contactor and caused a momentary power interruption. This short interruption resulted in the closure of the inboard shutdown cooling isolation valve and a loss of the operating decay heat removal system. The inspectors noted that decay heat removal from the reactor vessel was restored within five minutes. No appreciable increase in reactor vessel water temperature was identified.

Operations personnel initiated Condition Report 204095 and a prompt investigation following this self-revealing event. The prompt investigation determined the operator and the senior reactor operator failed to recognize that installing the jumpers in an alternate location presented an additional risk to the plant due to the proximity to the contacts. In addition, neither operator recognized that the additional risk should have been evaluated prior to jumper installation. At the conclusion of the inspection period, operations personnel had communicated this event to the remaining members of the department. The operations department was also working with the instrument maintenance department to determine alternate jumper installation methods and locations which reduced the potential risk to the plant. No violations of NRC requirements occurred since the licensee maintained the ability to operate the shutdown cooling suction valve from the drywell if needed.

4OA3 Event Follow-up (71153)

(Closed) Licensee Event Report 50-254/03-002-01: Mode Change with Core Spray Loop Inoperable due to Failure to Properly Fill and Vent.

During a review of the original event report, the inspectors noted that the information contained in the “Previous Occurrences” section was narrowly focused. Specifically, the licensee stated that there were no other instances of a reportable event involving the failure to properly perform venting due to an inadequate turnover or miscommunication. While this was true, the inspectors provided the licensee with a recently completed common cause analysis which documented more than ten system venting events. The inspectors also reviewed Section 5.2.5 of NUREG-1022, “Event Reporting Guidelines,” with the licensee to ensure that the licensee understood that the intent of the “Previous Occurrences” section of an event report was to identify any generic or recurring problems. Based upon this information, the inspectors determined that the large number of venting issues identified in the licensee’s common cause analysis should have been included in the original event report. On February 19, 2004, the licensee revised the original event report to include additional system venting events at Quad Cities in the “Previous Occurrences” section of the report. The inspectors reviewed the new information and had no additional concerns.

(Closed) Licensee Event Report 50-254/03-003-00: Failure of Reactor Main Steam Relief Valve Actuator Following Failure of the Pilot Valve Vent Line.

Introduction: The inspectors identified a Green finding and Non-Cited Violation due to the Unit 1, 1-0203-3B electromatic relief valve being found in an inoperable condition.

Description: On November 12, 2003, Unit 1 was shut down to repair the steam dryer. While performing drywell local area surveys, radiation protection personnel identified that the 3B electromatic relief valve pilot valve vent line was broken off at the pilot valve chamber assembly. Condition Report 186700 was initiated and Work Order 638286 was written to facilitate repairs.

On November 17, 2003, electrical maintenance technicians discovered internal damage to the electromatic relief valve actuator. The left side spring supporting the solenoid plunger was protruding through the brass bushing and one of two internal limit switches was missing from the limit switch arm. Based upon this information, the 3B electromatic relief valve solenoid actuator was removed and taken to the electrical maintenance shop for testing. The technicians determined that the solenoid actuator failed to operate in its current condition and thereby would not have opened the 3B electromatic relief valve when required. The licensee suspected that the 3B electromatic relief valve pilot solenoid actuator components were damaged due to increasing vibrations that occurred while the plant operated at power with the pilot vent line severed from the pilot valve chamber assembly.

The root cause of the 3B electromatic relief valve pilot valve vent line break was determined to be a lack of standard procedural instruction to identify, evaluate, and resolve issues concerning the cold spring forces on the small-bore lines during the 3B electromatic relief valve installation. The licensee concluded that the 3B electromatic relief valve pilot vent line failure resulted from fatigue cracking of the vent line under operating conditions. Analysis of the failed section of pipe indicated that the 1-inch carbon steel pilot vent line failed by fatigue due to a synergistic combination of stresses. These included residual installation stresses, bending, and operational vibration stresses concentrated at the toe of the vent line weld. This weld location was susceptible as a stress-riser due to the cross sectional change from the 3B electromatic relief valve body to the 1-inch pipe, a 20-mil deep mechanical indentation, and weld voids observed within this indentation. The cumulative affect of these issues led to the pipe failure when added to the pipe stress induced by the cold spring found in the pilot vent line.

Analysis: The inspectors determined that the failure to implement adequate procedural guidance to prevent cold spring stresses from degrading safety-related components to the point of inoperability beyond the Technical Specification limits was more than minor because it impacted the equipment performance and protection against external factors performance attributes of the mitigating systems cornerstone. In addition, this finding impacted the cornerstone objective of ensuring the availability, reliability, and capability of a system that responds to initiating events to prevent undesirable consequences since the electromatic relief valve was part of the automatic depressurization system.

The inspectors determined that this finding should be evaluated in accordance with Inspection Manual Chapter 0609, “Significance Determination Process,” (SDP) because the finding was associated with the operability, availability, reliability, and function of the Automatic Depressurization System function of the Low Pressure Coolant Injection System. The inspectors consulted the Significance Determination Process Phase 1 worksheet and determined that a Phase 2 evaluation was required based upon the finding representing an actual loss of safety function of a single train for greater than its Technical Specification Allowed Outage Time.

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 since the electromatic relief valve was determined to have been inoperable from approximately July 23 to November 11, 2003. For each Significance Determination Process worksheet completed, the inspectors assumed that all mitigating systems equipment was available except for the specific electromatic relief valve. The inspectors allowed credit for manual operator action to open additional electromatic relief valves if required during the accident condition. Using these assumptions, the inspectors evaluated nine core damage sequences. Worksheet results ranged from 7 to 12 points. The most dominant core damage sequence involved a medium Loss of Coolant Accident followed by a Transient without Power Conversion System and Loss Of Off-site Power. Based on the counting rule, the overall increase in risk was determined to be 7, therefore, the regional Senior Reactor Analyst evaluated the finding for both large early release frequency (LERF) and external event significance.

Utilizing Inspection Manual Chapter 0609, Appendix H, “Containment Integrity SDP,” draft Appendix H, and NUREG 1765, “Basis Document for LERF SDP,” the Senior Reactor Analyst concluded external events were not a major contributor to the overall risk significance to the finding. Therefore, this finding was of very low safety significance (Green) based on credit given to operators’ mitigating capability for taking manual action for depressurization and the fact that other mitigating systems were available.

<u>Enforcement</u>: Technical Specification 3.4.3.A requires that with one relief valve inoperable, restore the valve to operable status within 14 days or be in mode 3 within 12 hours and in mode 4 within 36 hours. In addition, Technical Specification 3.5.1.G requires that with one automatic depressurization system valve inoperable, restore the valve to operable status within 14 days or be in mode 3 within 12 hours and reduce reactor dome pressure to 150 psig or below within 36 hours. Contrary to the above, the licensee discovered on November 15, 2003, that automatic depressurization system valve 1-0203-3B was inoperable when required to be operable from July 23 until November 11, 2003. This violation is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004002-03).** This violation is in the licensee’s corrective action program as Condition Report 186700. Corrective actions for this event included repairing the electromatic relief valve and inspecting the remaining valves to ensure that they remained operable.

4OA5 <u>Other Activities</u>

<u>(Closed) Temporary Instruction 2515/154:</u> Spent Fuel Material Control and Accounting at Nuclear Power Plants. The inspectors completed Phase I and Phase II of the subject temporary instruction and provided the appropriate documentation to NRC management as required by the temporary instruction.

(Closed) Unresolved Item 50-254/01-08-02:  Calculations of Air in the High Pressure Coolant Injection and Reactor Core Isolation Cooling Lines Don't Appear to Support Operability.  After this item was opened, Dresden Station experienced a significant water hammer within their high pressure coolant injection system.  The root cause of this event and items which contributed to this event were reviewed by the Quad Cities Station engineering staff to ensure that Quad Cities was not susceptible to the same type of event.  Calculations were also reviewed to ensure adequate margin was available to minimize a potential water hammer event.  Corrective actions were implemented as needed following this review.  The Quad Cities engineering staff also completed a common cause evaluation of approximately ten system venting issues.  The licensee determined that several of the venting issues were created due to procedural inadequacies.  The inspectors reviewed the licensee's common cause evaluation for completeness, accuracy, and implementation of the associated corrective actions.  No problems were identified.

(Closed) Unresolved Item 50-254/02-08-02; 50-265/02-08-02:  Missed Inspections of the Control Rod Drive Housing Welds.  This issue was reviewed by the Office of Nuclear Reactor Regulation.  The NRC staff concluded that boiling water reactors that have not updated to the 1995 Edition of the Code, and apply the exemption of IWB-1220 do not have to inspect the control rod drive housings.  Quad Cities is an ASME 1989 Code Edition plant.  To demonstrate the makeup capability of the reactor core isolation cooling and safe shutdown makeup pump systems, the licensee performed Design Analysis No. QDC-0200-M-1279.  The analysis found that the makeup capability of 109 lb/sec (800 gpm) of the reactor core isolation cooling and safe shutdown makeup pump systems is greater than the potential leakage of 75 lb/sec due to a weld failure in the control rod drive housing.  For Quad Cities, the control rod drive housings would be exempt from surface and volumetric examinations per ASME, Section XI, IWB-1220(a).

(Closed) Unresolved Item 50-254/03-013-05:  Unexpected Damage to the Electromatic Relief Valves due to Vibration.  This issue was discussed in the closure of Licensee Event Report 05000254/2003003-00, "Failure of Reactor Main Steam Relief Actuator Following Failure of the Pilot Valve Vent Line."  (See Section 4OA3 of this report for additional details).

## 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 April 6, 2004.  The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary.

.2 <u>Interim Exit Meetings</u>

Interim exits were conducted for:

- Inservice inspection with Mr. T. Tulon on March 5, 2004.
- Access control to radiologically significant areas and the ALARA planning and controls programs with Mr. T. Tulon on March 5, 2004.

ATTACHMENT: SUPPLEMENTAL INFORMATION

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

Licensee
T. Tulon, Site Vice President
R. Gideon, Plant Manager
B. Swenson, Plant Manager (former)
R. Armitage, Training Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
T. Bell, Acting Engineering Manager
G. Boerschig, Work Control Manager
T. Hanley, Maintenance Manager
D. Hieggelke, Nuclear Oversight Manager
K. Leech, Security Manager
R. May, NDE Level III
K. Moser, Chemistry/Environ/Radwaste Manager
K. Ohr, ALARA Supervisor
M. Perito, Operations Manager
T. Wojcik, Engineering Programs Supervisor

Nuclear Regulatory Commission

M. Ring, Division of Reactor Projects - Branch 1
L. Rossbach, Office of Nuclear Reactor Regulation

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000254/2004002-01<br>05000265/2004002-01 | URI | Ability of Main Steam Valves to Meet Technical Specification Surveillance Requirement 3.4.3.1. (Section 1R15) |
| 05000254/2004002-02<br>05000265/2004002-02 | URI | Extended Power Uprate Power Levels (Section 1R20) |
| 05000254/2004002-03 | NCV | Automatic Depressurization System Valve 1-0203-3B was Inoperable When Required to be Operable (Section 4OA3) |

Closed

| | | |
|---|---|---|
| 05000254/2004002-03 | NCV | Automatic Depressurization System Valve 1-0203-3B was Inoperable When Required to be Operable |

| | | |
|---|---|---|
| 05000254/2003013-05 | URI | Unexpected Damage to the Electromatic Relief Valves due to Vibration |
| 05000254/2003002-01 | LER | Mode Change with Core Spray Loop Inoperable due to Failure to Properly Fill and Vent |
| 05000254/2003003-00 | LER | Failure of Reactor Main Steam Relief Valve Actuator Following Failure of the Pilot Valve Vent Line |
| 05000254/2001008-02 | URI | Calculations of Air in the High Pressure Coolant Injection and Reactor Core Isolation Cooling Lines Don't Appear to Support Operability |
| 05000254/2002008-02<br>05000265/2002008-02 | URI | Missed Inspections of the Control Rod Drive Housing Welds |

## LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

QCOS 0005-05; Increased Monitoring Surveillance; Revision 8

Updated Final Safety Analysis Report

Calculation QDC-3300-M-0872; CCST Time-Temperature Response Under Various Scenarios; Revision 0A

QCOP 0010-02; Required Cold Weather Routines; Revision 14

Temporary Configuration Change Permit 346527; Install Relay Block to Maintain CCST Heaters Functionality; dated January 7, 2004

Temporary Configuration Change Permit 347103; Document Leads Lifted for CCST Heaters - Declared Emergent; dated February 4, 2004

Condition Report 198447; CCST Tank Heater Breakers Frequently Tripping; dated January 30, 2004

Condition Report 197261; Emergent Modification on CCST/CST Heater Pushbutton Locks; dated January 23, 2004

Condition Report 193621; CCST Heater Reliability; dated January 6, 2004

Condition Report 198072; Recurring Heating System Problems; dated January 28, 2004

Condition Report 200169; CCST Heaters - Use of Increased Monitoring as a Compensatory Action; dated February 6, 2004

1R04 Equipment Alignment

QOM 1-2300-01; Unit 1 HPCI Valve Checklist; Revision 8

QOM 1-2300-02; HPCI System Fuse and Breaker Checklist; Revision 4

QCOS 2300-10; HPCI Monthly Valve Position Verification; Revision 7

QCAN 901(2)-3 B-16; Core Spray Discharge Header Hi/Lo Pressure; Revision 9

QCOS 0010-7; Equipment External Leakage Test; Revision 2

QCOP 1400-01; Core Spray System Preparation for Standby Operation; Revision 15

QCOP 1000-44; Unit 2 Alternate Decay Heat Removal; Revision 12

Piping and Instrumentation Diagram M-78; Diagram of Core Spray Piping; dated July 27, 1999

QOM 2-1400-08; Core Spray System Fuse and Breaker Checklist; Revision 4

QOM 2-1400-09; Unit 2 Core Spray Valve Checklist; Revision 3

QOM 2-1400-10; 2B Core Spray Valve Checklist; Revision 3

Bearing Oil Analyses for 2B Core Spray Pump; dated December 8, 2003

Bearing Oil Analyses for 2A Core Spray Pump; dated January 21, 2004

Condition Report 205717; Inadequate Thread Engagement on 1-1402-28B Inlet Flange Stud; dated March 3, 2004

Condition Report 205862; Wrong Oil in the 2A Core Spray Motor Upper and Lower Reservoir; dated March 3, 2004

Condition Report 205892; Wrong Oil in the 2B Core Spray Motor Upper and Lower Reservoir; dated March 3, 2004

Condition Report 205902; Incorrect Oil Labels on Upper and Lower Bearing Reservoirs 1B Core Spray; dated March 3, 2004

Condition Report 205908; No Oil Label on Upper or Lower Bearing Reservoirs 2B Core Spray Motor; dated March 3, 2004

Condition Report 205910; No Oil Label on Upper Oil Reservoir for 2A Core Spray Motor; dated March 3, 2004

Piping and Instrumentation Diagram 1900-01; Fuel Pool Cooling System; Revision 3

QCOP 3700-02; RBCCW System Startup and Operation; Revision 17

QCOP 1900-20; Using Fuel Pool Cooling System to Clean Up Reactor Cavity/Dryer-Separator Water; Revision 8

QCOP 1900-24; Unit 2 Fuel Pool Cooling System Startup and Shutdown; Revision 5

QOM 2-1900-01; U2 Fuel Pool Cooling Valve Checklist; Revision 5

QOM 2-3700-01; U2 RBCCW Valve Checklist; Revision 6

1R05 Fire Protection

OP-AA-201-005; Fire Brigade Qualification; Revision 2

OP-AA-201-003; Fire Drill Performance; Revision 6

QCMMS 4100-01; Fire Extinguisher and Hose Reel Inspection; Revision 18

OP-AA-201-001; Fire Marshall Tours; Revision 2

QCOA 0010-12; Fire/Explosion; Revision 24

Scenario for First Quarter 2004 Fire Drill

Quad Cities Units 1 and 2 Pre-Fire Plans

Quad Cities Units 1 and 2 Fire Hazards Analysis

Condition Report 198002; SCBA Respirator Failed During Fire Drill; dated January 28, 2004

Condition Report 204252; Weakness of First Quarter Fire Brigade Drills; dated February 19, 2004

EP-AA-1006; Quad Cities Units 1 and 2 Emergency Action Levels

1R07 Heat Sink

Updated Final Safety Analysis Report

Technical Specifications

QCOS 1000-29; RHR Heat Exchanger Thermal Performance Test; Revision 10

TIC-856; Allow IMD to Install Fluke at an Alternate Location for Flow Transmitter; dated February 9, 2004

1R08 Inservice Inspection

GE-PDI-UT-1; PDI Generic Procedure for the Ultrasonic Examination of Ferritic Piping Welds; dated December 9, 2003

AR #00132435; Jet Pump No. 2 and No. 7 AD-3b Cracks

1R13 Risk Assessment and Emergent Work

Daily Work Schedule; dated January 25-31, February 9-14, February 16-21, February 23-28, and March 8-13, 2004

Work Week Safety Profile for Weeks Ending January 31, February 14, February 21, February 28, and March 8, 2004

Exelon Risk Analyst's Review Notes for Weeks of January 26, February 9, February 16, February 23, and March 8.

WC-AA-104; Review and Screening for Production Risk; Revision 7

WC-AA-101; On-Line Work Control Process; Revision 8

1R14 Non-Routine Evolutions

Unit 2 Control Room Logs; dated February 2 and March 30 through 31, 2004

QCGP 3-1; Reactor Power Operations; Revision 38

QCOA 3500-01; Feedwater Temperature Reduction with Main Turbine On Line; Revision 21

QCOP 3500-05; Removing Low Pressure Feedwater Heaters From Service; Revision 8

QCOP 3500-03; Removing High Pressure Heaters From Service; Revision 10

QCOS 5600-10; Unit 2 Weekly Turbine Generator Tests; Revision 2

QCGP 2-3; Reactor Scram; Revision 49

QCGP 2-5; Post Scram Review; Revision 18

QGA 100; RPV Control; Revision 7

Condition Report 124187; 1D1 Heater Feedwater Side Relief Valve Blowing by Seat; dated September 23, 2003

Condition Report 198453; Unit 2 Feedwater Heater Condensate Side Relief Valve Leaking; dated January 25, 2004

Condition Report 198863; Emergency Load Drop due to Relief Valve 2-3621 Lifting; dated February 2, 2004

Condition Report 199065; Lessons Learned from 2D1 Heater Response; dated February 2, 2004

Unplanned Spread of Contamination due to 2D1 Heater Valve; dated February 2, 2004

Turbine Building Floor Drain Sump and Equipment Drain Sump Information; dated February 2, 2004

1R15 Operability Evaluations

Operability Evaluation 179235-08; Reactor Pressure Vessel Pressure and Temperature Limits; Revisions 0 and 1

Condition Report 179235; Potentially Non-Conservative Pressure Temperature Curves; dated October 3, 2003

Letter RS-03-113 from Patrick Simpson, Exelon Nuclear to USNRC Document Control Desk; Reactor Coolant System Pressure and Temperature Limits; dated June 6, 2003

Condition Report 100198; 125 Volt DC Ground on 3E Power Operated Relief Valve; dated March 20, 2002

Condition Report 99640; Level 3 Ground Unit 2 125 Volt Battery System; dated March 17, 2002

Condition Report 99577; Unit 2 125 Volt Battery Ground; dated March 16, 2002

Operability Evaluation 191530-08; 125 Volt DC Grounds on Two Power Operated Relief Valves; Revisions 0 and 1

Engineering Change Evaluation 343209; Engineering to Determine Correct Method to Adjust the Power Operated Relief Valve Limits; dated June 6, 2003

Engineering Change 340635; Lift Leads at 2-2202-32 Panel to Alleviate a 125 Volt DC Ground on the 2-0203-3E Annunciator Circuit; dated January 17, 2003

Engineering Change 346384; Lift Leads in 2-0203-3E Power Operated Relief Valve Indicating Circuit to Remove 125 Volt DC Ground; dated December 19, 2003

Engineering Change 346449; Lift Leads in 2-0203-3B Power Operated Relief Valve Indicating Circuit to Removed 125 Volt DC Ground; dated December 26, 2003

Operability Evaluation 148103; Moore Industries SCT Signal Converter/Isolator; Revision 2

Dresden Operability Evaluation 03-005; Moore Industries SCT Signal Converter/Isolator; Revision 0

Engineering Evaluation 347865; Assess Past Operability of Unit 2 Core Spray Pumps With Wrong Oil; dated March 12, 2004

Email from Bruce Jarnot, Exxon Mobil Corporation to Gerald Frizzell, Exelon Corporation; dated June 28, 2001

GENE Letter from W. J. Roit, GENE Electrical Services, to Larry King, Exelon Corporation; Subject: Dresden/Quad Cities Core Spray and Low Pressure Coolant Injection Motor and Pump Mechanical Seal Elevated Cooling Water Temperature Evaluation; dated March 16, 2001

GENE Letter DRF A61-0053 from W. J. Roit, GENE Electrical Services, to Larry King, Exelon Corporation; Subject: Dresden/Quad Cities Core Spray and Low Pressure Coolant Injection Motor and Pump Mechanical Seal Elevated Cooling Water Temperature Evaluation; dated May 2, 2001

GENE Project Task Report; Dresden and Quad Cities Extended Power Uprate Containment Systems Response Report; dated December 2000

1R17 Permanent Plant Modifications

Engineering Change 22082; Unit 2 Reactor Recirculation Control and Jet Pump Instrumentation Upgrade

TIC-0864; Unit 2 Reactor Recirculation Control System and Jet Pump Instrumentation Digital Upgrade; Revision 0

Digital Recirc Module for the Licensed Operator Initial Training Program; Reactor Recirculation Control System; Revision 0

Condition Report 203524; Engineering Change 22082 had Miscellaneous Deficiencies Requiring Revision; dated February 3, 2004

Engineering Change 342429; Add Safe Shutdown Makeup Pump Heating, Ventilation, and Air Conditioning Room Cooler Trouble Indications and Reset Pushbutton; Revision 0

Drawing Changes Associated with Engineering Change 342429

Condition Report 191445; Safe Shutdown Makeup Pump Room Cooler Modification Test Revision; dated December 17, 2003

Engineering Change 333573; Permanent Lead Shielding Around Recirculation Risers in Unit 2 Drywell; Revision 0

Engineering Change 343933; Replace Unit 2 PORVs with ERVs; Revision 0

Updated Final Safety Analysis Report

Technical Specifications

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

Updated Final Safety Analysis Report

Condition Report 207589; Fuel Oil Day Tank Alarm Received During QCOS 6600-43; dated March 12, 2004

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

Prompt Investigation for Condition Report 206673; Secondary Containment Breach Following High Pressure Coolant Injection Steam Line Drain Replacement; dated March 8, 2004

Plant Barrier Impairment Permit 2004-42; dated March 5, 2004

QOP 0020-01; Opening a Penetration in Secondary Containment; dated March 6, 2004

Condition Report 206673; Secondary Containment Breach Following High Pressure Coolant Injection Steam Line Drain Replacement; dated March 6, 2004

Condition Report 206294; Plant Barrier Impairment not Initiated for Core Boring into Secondary Containment; dated March 5, 2004

QCMMS 4100-31; Annual Cummins Diesel Fire Pump Engine Inspection; Revision 8

Condition Report 200622; Nuclear Oversight Identified QCMMS 4100-32 Enhancements; dated February 9, 2004

Work Order 542317-01; Mechanical Maintenance Diesel Fire Pump “A” Capacity Test; dated February 9, 2004

Condition Report 200717; ½ A Diesel Fire Pump Degrading Trend; dated February 10, 2004

QCOS 4100-01; Monthly Diesel Fire Pump Test; Revision 17

QCOS 6900-02; Station Safety Related Battery Quarterly Surveillance; Revision 17

PMED-891377-01; Development of a Duty Cycle Based on a More Conservative Application of Coincident Starting Currents for the 250 VDC Battery System; Revision 0

1R20 <u>Refueling and Outage</u>

GENE Services Information Letter 664, Supplement 1; BWR Steam Dryer Integrity; dated September 5, 2003

Q2R17 Shutdown Safety Overview; no date available

Q2R17 Level 1 Schedule; dated February 11, 2004

Quad Cities Unit 2 Steam Dryer Inspection Handout; dated March 8, 2004

Quad Cities Unit 2 Steam Dryer Repairs Handout; dated March 24, 2004

Quad Cities Unit 2 Shutdown Safety Profile; various dates

Q2R17 Key Systems Used for Shutdown Safety; various dates

General Electric Field Deviation Disposition Request EE2-0537; dated March 2, 2004

General Electric Field Deviation Disposition Request EE2-0538; dated March 3, 2004

Indication Notification Report Q2R17-04-01; Dryer Internal Lower Strut Indication; dated February 26, 2004

Indication Notification Report Q2R17-04-02, Revision 1; Dryer Internal Upper Support Indications; dated February 28, 2004

Indication Notification Report Q2R17-04-03; Dryer Drain Channel and Skirt Indications; February 27, 2004

Indication Notification Report Q2R17-04-04, Revision 3; Dryer Internal Horizontal Weld Indications; dated March 2, 2004

Indication Notification Report Q2R17-04-05; Dryer Internal Vertical Weld Indication; dated February 28, 2004

Indication Notification Report Q2R17-04-06; Revision 3; Dryer Guide Channel Indication; dated March 3, 2004

Indication Notification Report Q2R17-04-07; Dryer Drain Channel Indications DC-A-180; dated February 28, 2004

Indication Notification Report Q2R17-04-08; Steam Dryer Exterior End Plate Indications; dated February 29, 2004

Indication Notification Report Q2R17-04-09; Steam Dryer Exterior Tie Bar Indications; dated March 1, 2004

Indication Notification Report Q2R17-04-10; Steam Dryer Exterior Hold Down Assemblies; dated March 2, 2004

Indication Notification Report Q2R17-04-11; Steam Dryer Outer Hood Gussets; dated March 2, 2004

Indication Notification Report Q2R17-04-12; Steam Dryer Exterior Hood Plate Indications; dated March 3, 2004

Indication Notification Report Q2R17-04-13; Guide Rods; dated March 7, 2004

Indication Notification Report Q2R17-04-15; Jet Pump Wedges; dated March 8, 2004

Indication Notification Report Q2R17-04-16, Revision 1; Feedwater Sparger Brackets; dated March 9, 2004

Indication Notification Report Q2R17-04-17; Top Guide Rim Weld 11; dated March 9, 2004

Indication Notification Report Q2R17-04-18; Perforated Plate 1, 2, 3, and 21 Weld Indications; dated March 21, 2004

Indication Notification Report Q2R17-04-19; Horizontal Plate 17, 16, and 19 Weld Indications; dated March 22, 2004

Indication Notification Report Q2R17-04-20; Perforated (Horizontal) Plate 06 and 07 Weld Indications; dated March 22, 2004

1R22 Surveillance Testing

Updated Final Safety Analysis Report

Technical Specifications

Work Order 648518-01; Diesel Generator Load Test

Work Order 600010-01; Diesel Generator Timed Start

NUREG-1022; Event Reporting Guidelines 10 CFR 50.72 and 50.73; Revision 2

Condition Report 199755; Bus 24-1 Degraded Voltage Relays Found Out of Tolerance; dated February 5, 2004

Condition Report 199880; Nuclear Oversight Identified Peer Check Used in Lieu of Concurrent Verification; dated February 5, 2004

Drawing 4E-2334; Relaying and Metering Diagram 4160 Volt Switchgear Buses 23-1 and 24-1; Revision AD

Drawing 4E-2346; Schematic Drawing 4160 Volt Bus 24-1 Standby Diesel 2 Feed and 24-1 Tie Breaker Sheet 1; Revision AM

Drawing 4E-2346; Schematic Drawing 4160 Volt Bus 24-1 Standby Diesel 2 Feed and 24-1 Tie Breaker Sheet 2; Revision AN

Q2R17 Main Steam Isolation Valve Local Leak Rate Test Results and Recovery Plan

QCTP 0130-01; Leak Rate Testing Program; Revision 17

QCMMS 4100-31; Annual Cummins Diesel Fire Pump Engine Inspection; Revision 8

Condition Report 200622; Nuclear Oversight Identified QCMMS 4100-32 Enhancements; dated February 9, 2004

Work Order 542317-01; Mechanical Maintenance Diesel Fire Pump “A” Capacity Test; dated February 9, 2004

Condition Report 200717; ½ A Diesel Fire Pump Degrading Trend; dated February 10, 2004

QCOS 4100-01; Monthly Diesel Fire Pump Test; Revision 17

Condition Report 196912; Auto Transfer of MCC 28/29-5 Time Out of Tolerance; dated January 22, 2004

Condition Report 131936; Missing Bellville Washer in 1-0203-2C MSIV; dated November 16, 2002

Condition Report 203885; As Found Local Leak Rate Test Main Steam Isolation Valve Max Pathway Greater than 46 scfm; dated February 24, 2004

QCTS 0210-04; Setup and Use of the BCT-2000 Battery/Charger Test Computer; Revision 3

QCOS 6900-02; Station Safety Related Battery Quarterly Surveillance; Revision 17

PMED-891377-01; Development of a Duty Cycle Based on a More Conservative Application of Coincident Starting Currents for the 250 VDC Battery System; Revision 0

Work Order 481760; Drywell Closeout; dated March 27, 2004

1R23 <u>Temporary Modifications</u>

Engineering Change 345750; Use Service Water to Pressurize Residual Heat Removal Service Water at 2A Residual Heat Removal Heat Exchanger to Minimize Internal Leakage; Revision 1

Drawing Changes Associated with Engineering Change 345750

Updated Final Safety Analysis Report

Technical Specifications

CC-AA-112; Temporary Configuration Changes; Revision 7

<u>2OS1</u> <u>Access Control to Radiologically Significant Areas</u>
<u>2OS2</u> <u>ALARA Planning And Controls</u>

CR 204161; Venture Carpenter Exited The RCA Wearing A Skull Cap; February 25, 2004

CR 204085; Found Dosimeter Alarming In U2 RCIC/2B Core Spray Room; February 25, 2004

AR 185378; Recommendations For WBC Program Improvements; November 7, 2003

AR 186161; Scorecard Trend Of Dosimetry Issues; November 12, 2003

AR 186509; Unplanned Spread Of Contamination; November 14, 2003

AR 186575; Individual Arrived At QC With Contaminated Shoes; November 9, 2003

AR 187056; Unplanned Spread Of Contamination (U2 Sample Panel); November 17, 2003

AR 187067; Unplanned Spread Of Contamination (U1 EHC Skid); November 16, 2003

AR 187439; Unable To Release LHRA Due To Inadequate Flush; November 20, 2003

AR 187825; Contaminated Water Draining Onto The MSIV Room Floor; November 21, 2003

AR 188443; Heavy Items Hanging From Unit 1 SFP Hand Rail; November 29, 2003

AR 188600; INPO Assist Visit Identified Weaknesses In Exposure Control; October 31, 2003

AR 188602; INPO Assist Visit Identified Weaknesses In Contamination Control; October 31, 2003

AR 189809; Individual E.D. Alarm Investigation; December 6, 2003

AR 191806; Higher Than Expected Dose Rates On The 1-1904-46A Valve; December 16, 2003

CR 204657; Q2R17-PCE Hooking Up Decon Equipment DW Basement; February 26, 2004

CR 204527; Worker Lost Electronic Dosimeter; February 27, 2004

AR 192402; Emergent Dose Cleaning RW Basement; December 17, 2003

AR 197351; Radiological Postings in The RCA Don't Match RWP Instructions; January 1, 2004

AR 197647; Workers Entered HRA Without HRA Brief; January 26, 2004

AR 198903; Unplanned Spread Of Contamination Due To 2D1 Heater Valve; February 2, 2004

AR 202191; Unplanned Spread Of Contamination Due To Leaching; February 14, 2004

LS-AA-126-1005; CHECK-IN Self Assessment Report: ALARA Planning and Controls; February 20, 2004

NOSPA-QC-03-2Q; Continuous Assessment Report; July 30, 2003

NOSPA-QC-03-4Q; Continuous Assessment Report; January 23, 2004

NOSPA-QC-03-3Q; Continuous Assessment Report; October 28, 2003

NOSA-QDC-03-06; NOS HP/RP Audit Exit Report; May 21, 2003

RWP 10003160; ALARA/RP Brief: Q2R17 Sandblasting (Turbine); February 26, 2004

RWP 10003560; ALARA Plan: (U2 DW) Replace Four PORVs With ERVs; February 23, 2004

RWP 10003074; ALARA Plan: (U2 DW) Control Rod Drives: Remove/Replace; February 18, 2004

RWP 10003566; ALARA Plan: (U2 DW) Weld Overlays; February 19, 2004

RWP 10003100; ALARA Plan: (U2 DW) 21-0220-57A RFW Valve Repair; February 18, 2004

RWP 10003535; ALARA Plan: 2A RHR Heat Exchanger: Repair Internal Leakage; February 18, 2004

RWP 10003171; ALARA Plan: U2 RX Disassembly/Reassembly/Cavity Work/Wall Cleaning; February 18, 2004

RWP 10003159; U2 Main Turbine Overhaul/PM; February 23, 2004

RWP 10003830; Ultrasonic Fuel Cleaning; Revision 1

RP-AA-401; Operational ALARA Planning and Control; Revision 2

RP-AA-222; Methods For Estimating Internal Exposure From In Vivo and In Vitro Bioassay Data; Revision 1

10003559; Work In Progress Review: U2 DW Permanent Shielding; March 4, 2004

10003142; Work In Progress Review: Outboard MSIV: Internal Valve Repairs; March 3, 2004

10003181; Work In Progress Review: U2 Rx Steam Dryer: Tie-Bar Repair (Divers); February 29, 2004

10003171; Work In Progress Review: U2 Rx Disassembly/Reassembly; February 27, 2004

10003832; Work In Progress Review: 2-1203-C RWCU HX: Remove Furminite Clamp/Repair; March 2, 2004

10003830; Work In Progress Review: BWR Fuel Cleaning: Ultrasonic Fuel Cleaning Pilot Campaign; January 28 and 30, 2004

LS-AA-104-1001; Ultrasonic Cleaning of GE 14 Bundles; Revision 1

CR 198111; Fuel Bundle FME and Spacer Changes After Ultrasonic Cleaning; January 29, 2004

BWR Fuel Cleaning Status; September 8, 2003

BRAC Data Unit 2; Three Year Rolling Average; March 4, 2004

Unit 2, A and B Recirc Loops; BRAC Point Dose Rates; March 3, 2004

Unit 2 Drywell Surveys; February 24 and March 1, 2004

4OA1 Performance Indicator Verification

Control Room Logs; dated January through December 2003

LS-AA-2010; Monthly Performance Indicator Data Elements for Unplanned Scrams per 7000 Critical Hours; Revision 3

LS-AA-2020; Monthly Performance Indicator Data Elements for Unplanned Scrams with Loss of Normal Heat Removal; Revision 3

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

LS-AA-2100; Monthly Performance Indicator Data Elements for Reactor Coolant System Leakage; Revision 4

4OA3 Event Follow-up

Condition Report 186979; 3B ERV Actuator Found Damaged; dated November 17, 2003

Condition Report 187787; 3C ERV Showing Excessive Wear; dated November 22, 2003

Condition Report 187788; 3D ERV Shows Excessive Wear; dated November 22, 2003

Condition Report 187789; 3E ERV Shows Excessive Wear; dated November 22, 2003

Condition Report 188202; Documentation Results of Extent of Condition for ERV Vibration; dated November 25, 2003

Condition Report 188204; Dresser ERV Torque Specifications Not Included in Procedures; dated November 25, 2003

4OA5 Other Activities

Temporary Instruction 2515/154; Spent Fuel Material Control and Accounting at Nuclear Power Plants; dated November 26, 2003

Quad Cities Station Annual Physical Inventory; dated July 14, 2003

Special Nuclear Material Monthly Report; dated January 1, 2004

NF-AA-310; Move Cover Sheet for Inspection of Leaker Assembly #1; dated November 6, 2002

NF-AA-310; Move Cover Sheet for Move of Single Rod C-9 From Bundle Q7D210 to the Temporary Storage Basket; dated June 7, 2002

NF-AA-310; Special Nuclear Material and Core Component Movement; Revision 6

NF-AA-330; Special Nuclear Material Physical Inventory; Revision 1

## LIST OF ACRONYMS USED

| | |
|---|---|
| ALARA | As Low As Is Reasonably Achievable |
| ASME | American Society of Mechanical Engineers |
| CFR | Code of Federal Regulations |
| DRS | Division of Reactor Safety |
| gpm | Gallons Per Minute |
| HEPA | High Efficiency Particulate Air |
| lb | Pound |
| LERF | Large Early Release Frequency |
| NRC | Nuclear Regulatory Commission |
| PI | Performance Indicator |
| RWP | Radiation Work Permit |
| SDP | Significance Determination Process |