January 20, 2005

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

SUBJECT: QUAD CITIES NUCLEAR POWER STATION, UNITS 1 AND 2
NRC INTEGRATED INSPECTION REPORT 05000254/2004010; 05000265/2004010

Dear Mr. Crane:

On December 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 January 4, 2005, with Mr. T. 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 seven issues of very low safety significance (Green). Each of these issues involved a violation of NRC requirements. However, because these violations were of very low safety significance and because the issues were entered into your corrective program, the NRC is treating these findings and issues as Non-Cited Violations in accordance with Section V1.A.1 of the NRC's Enforcement Policy.

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

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Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000254/2004010; 05000265/2004010
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
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Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional
Operating Group
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Vice President - Law and Regulatory Affairs
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	05000254/2004010; 05000265/2004010
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	October 1 through December 31, 2004
Inspectors:	K. Stoedter, Senior Resident Inspector M. Kurth, Resident Inspector A. Dunlop, Senior Reactor Engineer, DRS J. House, Senior Radiation Specialist, DRS J. Neurauter, Reactor Engineer, DRS B. Palagi, Senior Operations Engineer R. Ganser, Illinois Emergency Management Agency
Approved by:	M. Ring, Chief Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000254/2004010, 05000265/2004010; 10/01/2004-12/31/2004; Quad Cities Nuclear Power Station, Units 1 & 2; Operability Evaluations, Post Maintenance Testing, Event Followup, and Other.

This report covers a 3-month period of baseline resident inspection and announced baseline inspections on the radioactive gaseous and liquid effluent treatment and monitoring systems, and the licensed operator requalification program. The inspection was conducted by Region III inspectors and the resident inspectors. In addition, followup inspection of an unresolved item was conducted by regional engineering specialist inspectors. Seven Green findings associated with seven non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

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

Cornerstone: Mitigating Systems

- Green. A self-revealing finding of very low safety significance was identified during post maintenance testing of the 1A residual heat removal service water system on October 7. Several human performance deficiencies resulted in operations personnel starting the 1A residual heat removal service water pump without a discharge flow path. The deficiencies included: a failure to follow the licensee's locking and tagging procedure when developing system return to service instructions; the use of unverified assumptions when developing return to service instructions; weaknesses in briefings; and deficient control board panel monitoring. A Non-Cited Violation of Technical Specification 5.4.1 was also identified.

  The inspectors determined that this issue was more than minor because the failure to follow procedure, the inadequate briefings, and the deficient panel monitoring resulted in creating a sizeable leak in the residual heat removal service water system and operating a system in a condition which had the potential to lead to pump damage. This issue was of very low safety significance because the leak did not result in a loss of safety function for the residual heat removal service water system. Corrective actions for this issue included briefing operations personnel on the issue, improving human performance in the operations department, and repairing the leak. (Section 1R19)

- Green. The inspectors identified a finding of very low safety significance involving a Non-Cited Violation of Technical Specification 3.4.3 due to the Unit 2 target rock valve being unable to actuate within plus or minus one percent of its nameplate value during as-found testing conducted in April 2004.

This issue was determined to be more than minor because if left uncorrected, this condition could put the licensee at risk for exceeding their vessel overpressure limits following an accident or an anticipated transient without scram. This issue was of very low safety significance because the actuation of the valve at the higher setpoint would not have resulted in exceeding the pressure limits assumed in the licensee's current analyses. Corrective actions for this issue included installing a new valve, performing additional testing to better understand the degradation mechanism, operating the Quad Cities units at pre-extended power uprate power levels, developing a modification to install better materials in the bellows cap area, and continuing the ongoing vibration assessments. (Section 4OA3.1)

- Green. A finding of very low safety significance was self-revealed when the setpoints for two of the Unit 1 low pressure coolant injection loop select low pressure switches were found above Technical Specification value on July 30, 2004. The inspectors determined that an unapproved modification had resulted in the removal of one of two internal micro-switches which caused the pressure switches to drift more than expected. The implementation of an unapproved modification was determined to be a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control."

  This issue was determined to be more than minor because if left uncorrected, the unapproved modification could result in the switch setpoints drifting above both the Technical Specification limits and the allowable value. However, this finding was determined to be of very low safety significance because it did not result in an actual loss of safety function for the low pressure coolant injection system. The licensee's short term actions included increasing the pressure switch testing frequency and performing an extent of condition review to determine whether other switches had been modified. In the long term, the licensee planned to replace the pressure switches, or return the installed pressure switches to their original design, during the next refueling outage. (Section 4OA3.2)

- Green. A finding of very low safety significance and a Non-Cited Violation of Technical Specification 3.4.3 were identified by the inspectors in November 2004 due to the licensee's repeated inability to demonstrate that the main steam safety valves would actuate within plus or minus one percent of the nameplate value when required.

  This issue was determined to be more than minor because it led to continued degradation of the main steam safety valves and put the licensee at risk for exceeding their vessel overpressure limits following an accident or an anticipated transient without scram. This finding was of very low safety significance because an adequate number of safety valves and relief valves were available to prevent an overpressure condition from occurring. Corrective actions for this issue included installing new main steam safety valves, submitting a license amendment to change the main steam safety valve operating tolerances, and revising a previously issued Licensee Event Report to report the previous failures. (Section 4OA5.1)

- Green. The inspectors identified a finding and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," in May 2004 when they discovered that the design of the reactor core isolation cooling system did not provide adequate capability to isolate the safety-related torus from the non-seismic reactor core isolation cooling system under all conditions. As a result, torus water could potentially drain into the reactor building following a seismic event and a failure of the reactor core isolation cooling piping. The loss of torus inventory could potentially affect the safety-related water supply for the emergency core cooling systems.

This finding was more than minor since it could have affected the mitigating cornerstone objective of ensuring the availability of systems required to respond to initiating events. This finding was of low safety significance because a subsequent evaluation demonstrated that the reactor core isolation cooling piping would not have failed during a seismic event. The licensee initiated a procedure change to remotely bypass the valve control logic such that the reactor core isolation cooling system remained operable and the operators could close the valve when required for containment isolation. The licensee also initiated engineering changes to revise the valve control logic as a permanent resolution to the issue. (Section 4OA5.2)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” in August 2004 due to the licensee’s failure to adequately translate code design requirements into an operability evaluation for the main steam safety relief valve discharge line flanges.

  This issue was more than minor because if left uncorrected the failure to perform adequate operability evaluations could become a more significant safety concern. This issue was of very low safety significance because it did not involve the degradation of a radiological barrier, a barrier used to protect the control room from smoke or toxic gases, and did not result in an actual open pathway in the physical integrity of the reactor containment. As part of the corrective actions for this issue, the licensee implemented compensatory actions to ensure continued operability of the installed flanges and initiated plans to modify the operable but degraded flanges to meet their design requirements. (Section 1R15)

- Green. A finding of very low safety significance and a Non-Cited Violation of Technical Specification 3.7.4.A were identified by operations personnel in October 2004 due to the licensee’s failure to demonstrate that the control room emergency ventilation system was capable of maintaining the control room emergency zone differential pressure at greater than 1/8 of an inch at a flow rate of 2000 standard cubic feet per minute since 1998.

  This issue was determined to be more than minor because if left uncorrected, the condition of the control room emergency ventilation system would have continued to degrade without being identified by the licensee. This issue was of very low safety significance since the finding only represented a degradation of the radiological barrier provided for the control room. Corrective actions for this issue including providing additional sealing material to the cable tunnel hatch covers and revising the control room emergency ventilation surveillance procedures to ensure that the Technical Specifications continue to be met. (Section 4OA3.3)

B. Licensee-Identified Violations

No findings of significance were identified.

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at approximately 85 percent power until December 12 when reactor power was reduced to perform a control rod pattern adjustment, control rod scram timing, and repair the flexible tubing on the feedwater regulating valves. Operations personnel returned Unit 1 to 85 percent power the following day. Reactor power remained at this level through the conclusion of the inspection period.

Unit 2 entered the inspection period operating at 85 percent power. Operations personnel performed one planned and two unplanned load reductions during the period. In early October, the licensee completed a planned load reduction to perform a control rod pattern adjustment and control rod scram timing. Later in the month, another load reduction was needed to repair a degraded hydraulic hose on the 2A feedwater regulating valve actuator. On December 24 operations personnel completed a small power reduction to perform turbine valve testing. Following this load reduction, Unit 2 operated at 85 percent power through the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

From November 29 through December 23, 2004, the inspectors assessed the licensee's readiness for cold weather conditions by conducting detailed inspections on the reactor building heating system and the contaminated condensate storage tanks. The inspectors chose the reactor building heating system because of its importance in maintaining the operability of safety-related equipment and piping exposed to cold temperature conditions. The contaminated condensate storage tanks were selected for review due to their importance in response to a loss of coolant accident. The inspectors reviewed the Updated Final Safety Analysis Report and the seasonal readiness and adverse weather procedures to determine the operational requirements of the reactor building heating system and contaminated condensate storage tanks during cold weather conditions. The inspectors reviewed previously initiated issue reports related to cold weather conditions and performed plant walkdowns to ensure that the items documented in the issue reports had been appropriately corrected. This inspection represented the completion of two inspection samples.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

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

- Residual Heat Removal Loop 2A, and
- Residual Heat Removal Loop 1B.

The inspectors utilized the valve and breaker checklists listed at the end of this report to verify that components were properly positioned and that support systems were configured 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 issue reports associated with each system to verify that those documents did not reveal issues that could affect equipment operability. The inspectors also used the information in the appropriate sections of the Updated Final Safety Analysis Report to determine the functional requirements of the systems. This review constituted the completion of two inspection samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

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

- Fire Zone 11.2.4 - 1A Residual Heat Removal Room (due to an inspector identified degraded fire door);
- Fire Zone 5.0 - Safe Shutdown Makeup Pump Room;
- Fire Zone 9.3 - ½ Emergency Diesel Generator;
- Fire Zone 6.3 - Auxiliary Electric Room; and
- Fire Zone 3.0 - Cable Spreading Room.

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

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

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

- Potential for Flooding Emergency Core Cooling System Corner Room due to Reactor Core Isolation Cooling Pipe Break Following a Seismic Event, and

- Potential Open Flood Path Between Residual Heat Removal Service Water Vaults due to Opening Valve During Maintenance.

The inspectors used the documents listed at the end of this report to accomplish the objectives of the inspection procedure. The inspection focused on verifying that flood mitigation plans and equipment were maintained when required and that the plans were consistent with design requirements and risk analysis assumptions. The inspection activities included, but were not limited to, visually inspecting the installed design measures, seals, and drain systems to verify their adequacy, reviewing the results of flooding related equipment surveillance tests to ensure that acceptance criteria were met, reviewing the flooding and surveillance procedures for technical adequacy, and conducting interviews and walkdowns to ensure that any required compensatory measures were implemented if needed. The inspectors also verified that issues regarding flooding protection had been entered into the licensee's corrective action program for resolution. These reviews represented the completion of two internal flooding inspection samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Quarterly Simulator Observation (71111.11Q)

a. Inspection Scope

On November 3, 2004, the inspectors observed an operations crew in the simulator performing Licensed Requalification Exam Scenario Number 00-18. The scenario consisted of a toxic gas analyzer failure, a leak in the drywell, an electrical anticipated transient without and scram, and a reactor pressure vessel blowdown.

The inspectors evaluated crew performance in the areas of:

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

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

- OP-AA-101-111, “Rules and Responsibilities of On-Shift Personnel,” Revision 1;
- OP-AA-103-102, “Watchstanding Practices,” Revision 3; and
- OP-AA-104-101, “Communications,” Revision 1.

The inspectors verified that the crew completed the critical tasks listed in the scenario. If critical tasks were not met, the inspectors verified that crew and operator performance errors were detected and adequately addressed by the evaluators. Lastly, the inspectors observed the licensee’s critique to verify that weaknesses identified during this observation were noted by the evaluators, discussed with the respective crews, and entered into the corrective action program if needed. This observation represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

.2 Annual Operating Test Results (71111.11B)

a. Inspection Scope

The inspector reviewed the overall pass/fail results of individual Job Performance Measure operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during calender year 2004. The overall results were compared with the significance determination process in accordance with NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process.”

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12)

a. Inspection Scope

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

- Core Spray System (Function Z1400), and
- 480 Volt Breakers (Function Z7800).

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

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the documents listed in the "List of Documents Reviewed" section of this report to determine if the risk associated with the listed activities agreed with the results provided by the licensee's risk assessment tool. The inspectors conducted walkdowns to ensure that redundant mitigating systems credited by the licensee's risk assessment remained available. When compensatory actions were required, the inspectors conducted plant tours to validate that the compensatory actions were implemented. The inspectors 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. Lastly, the inspectors performed a word search review of the licensee's corrective action database to ensure that problems related to risk assessments were entered into the licensee's corrective action program. This review represented the completion of one inspection sample.

- Work Week of October 4 - 10, 2004, including planned maintenance on the 1A residual heat removal service water loop and the 2D residual heat removal pump.

b. <u>Findings</u>

No findings of significance were identified.

1R15 <u>Operability Evaluations</u> (71111.15)

a. <u>Inspection Scope</u>

The inspectors assessed the acceptability of the following operability evaluations:

- Operability Evaluation 186375, "Main Steam Safety Relief Valve Discharge Lines Built to Incorrect Piping Design Information;" and
- Operability Evaluation 220863, "First Stage Set Pressure Set Point of the Unit 1 Target Rock Safety Relief Valve may be Higher Than Expected due to Vibration Induced Wear," and Operability Evaluation 200772, "Potential for As-Found Main Steam Safety Valve Setpoints to Exceed the Plus or Minus One Percent Criteria."

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," Revision 0.

In addition, the inspectors reviewed selected issues that the licensee entered into its corrective actions program to verify that identified problems were being entered into the program with the appropriate characterization and significance. These reviews represented the completion of two inspection samples.

b. <u>Findings</u>

<u>Introduction</u>: The inspectors identified one green finding due to the failure to adequately translate code design requirements into an operability evaluation for the main steam safety relief valve discharge line flanges. This failure was determined to be a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," and resulted in the flanges being "operable but degraded" rather than fully operable.

<u>Description</u>: On November 13, 2003, the licensee initiated Condition Report 186375 when they discovered conflicting information regarding main steam safety relief valve discharge flange design. Specifically, the Plant Unique Analysis Report for the main steam safety relief valve discharge lines indicated a maximum pressure (transient) and temperature of 550 psig and 380EF, respectively. Under these conditions, the American National Standards Institute standards required installation of American National Standards Institute B16.5 Class 300 flanges rather than the American National Standards Institute B16.5 Class 150 flanges that were installed during original plant construction. The licensee performed Analysis No. QDC-3000-1351, "SRV Discharge Line Flange Evaluation," Revision 0, as part of the operability evaluation for this issue

and concluded that the installed 8 inch diameter, Class 150, discharge flanges met Code requirements. As a result, the licensee did not plan to perform any additional corrective actions. The inspectors reviewed the operability evaluation on August 20, 2004, and had the following observations:

- The licensee's calculated bolt area under stress was non-conservative. The American Society of Mechanical Engineers Code specified that the cross sectional area of bolts at the root of threads or the bolt section of least diameter under stress be used for flange design. However, Analysis QDC-3000-1351 failed to use the cross sectional area of the bolts at the root of the threads. The inspectors determined that the actual bolt area calculated using the cross sectional area of bolts at the root of threads was less than the Code required bolt area. Therefore, the 8 inch diameter flanges did not meet Code design requirements.

- Analysis QDC-3000-—1351 used the design rules of American Society of Mechanical Engineers Section VIII (1965) to evaluate the flange acceptability. The inspectors determined that Updated Final Safety Analysis Report, Section 6.2.1.3.4.2, indicated that the safety relief valve discharge lines complied with the rules American Society of Mechanical Engineers Section III, Subsection NC, 1977 Edition though Summer 1977 Addenda to meet Class 2 system requirements. Due to this oversight, Analysis QDC-3000-—1351 did not include all the piping mechanical loads as stipulated by American Society of Mechanical Engineers Section III, Subsection NC for flange evaluations.

Based on the inspectors observations, the licensee re-opened the operability evaluation and re-performed the analysis including the cross sectional area of bolts at the root of threads and the additional mechanical loads. The calculations confirmed that loading on the 8 inch diameter flanges exceeded Code requirements but that the yield stresses were not exceeded for the existing flange material. Therefore, the 8 inch diameter flanges were operable but degraded. However, corrective actions were required to ensure that the flange design met code requirements.

<u>Analysis</u>: The inspectors determined that the failure to perform an adequate operability evaluation was a performance deficiency warranting a significance evaluation. The inspectors concluded that the finding was greater than minor because if left uncorrected, the failure to perform adequate operability evaluations could become a more significant safety concern. If the inspectors had not intervened the licensee would not have taken action to bring the safety relief valve discharge lines flanges up to Code requirements.

The inspectors completed a Phase 1 significance determination of this issue using IMC 0609, "Significance Determination Process (SDP)," Appendix A, dated September 10, 2004. The inspectors determined that this finding impacted the containment barrier cornerstone. The safety relief valve discharge lines flanges were in the torus atmosphere space. Any failure in the flange material would result in steam entering the atmosphere above the water instead of being condensed under the water. The steam would more rapidly increase the pressure within the torus. The inspectors entered the containment barriers cornerstone column of the Phase I significance determination process worksheet and answered “no” to all three questions. Therefore the inspectors concluded that the finding was of very low safety significance (Green).

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. This design basis requirement is to maintain safety relief valve discharge line flange stresses below Code acceptance limits.

Contrary to the above, as of November 13, 2003, the licensee failed to assure that the design basis requirement to maintain the safety relief valve discharge line flange stresses below Code acceptance limits was correctly translated into operability evaluation 186375. As a result, the licensee incorrectly concluded that the flanges were fully operable and failed to recognize that corrective actions were necessary to ensure the flanges met Code requirements. However, because this violation was of very low safety significance, and because the issue was entered into the licensee’s corrective action program as Issue Report 247298, the issue is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-01; 05000265/2004010-01)**. As part of the corrective actions for this issue, the licensee implemented compensatory actions to ensure continued operability of the installed flanges and initiated plans to replace the existing Class 150 flanges with Class 300 flanges during the upcoming outages on each unit.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors assessed the cumulative effects of all operator workarounds at the station as of November 29, 2004. The inspectors utilized the Updated Final Safety Analysis Report and the Technical Specifications to determine the safety function of each system impacted by an operator workaround. Once the safety function was determined, the inspectors reviewed the contents of corrective action documents, modification packages, and procedure changes to determine the nature of the operator workaround and future actions to resolve each deficiency. After gaining a thorough understanding of each workaround, the inspectors interviewed licensee personnel and reviewed normal, abnormal, and emergency operating procedures to determine the potential effects of each workaround on the functionality of the corresponding systems. The inspectors also performed a word search on the corrective action program database to ensure that the licensee was entering issues associated with operator workarounds into the corrective action program with the appropriate characterization and significance. This review represented the completion of one cumulative review sample.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Corrective maintenance on the 480 Volt breaker for MOV1-1001-26A, residual heat removal containment spray loop downstream isolation valve; and

- Planned maintenance on multiple components in the 1A residual heat removal service water loop.

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

b. Findings

Leak Created on 1A Residual Heat Removal Service Water Loop During Post Maintenance Testing

Introduction: One self-revealing Green finding was identified when operations personnel started the 1A residual heat removal service water pump for post maintenance testing without an appropriate discharge flow path. The inadequate flow path was inadvertently established due to several human performance deficiencies including: a failure to follow the licensee's valve locking and tagging procedure when developing system return to service instructions, the use of unverified assumptions in developing the system return to service instructions, weaknesses in pre-job briefings, and deficient control board panel monitoring. A violation of Technical Specification 5.4.1 was also identified due to the failure to appropriately implement the locking and tagging procedure.

Description: On October 5, operations personnel removed the 1A residual heat removal service water pump from service for planned maintenance using clearance order 27817. This clearance order utilized several non-carded steps, which directed operations personnel to close the valves used to control the flow of residual heat removal service water to the residual heat removal heat exchanger in both the normal and reverse directions, without having to place a clearance order tag at the equipment location. After closing the valves, additional non-carded steps were used ensure that each of the reversing valve breakers was in the off position.

The following day a clearance order writer began developing the 1A residual heat removal service water system return to service instructions. The clearance order writer removed the non-carded steps and replaced them with a special instruction on the first page of the clearance order which stated, "Place the 1A residual heat removal heat exchanger valves in normal or reverse flow per the Unit Supervisor." This action directly conflicted with Step 7.1.9 of OP-MW-109-101, "Clearance and Tagging," which required all components manipulated during clearance activities be tracked with a tag, by a non-carded step, or by a procedure that governs the manipulation. Due to other activities, the clearance order writer was unable to finish the return to service instructions. As a result, the instructions were left in a planning status so that they could be finished the following day.

During the overnight hours, the 1A residual heat removal service water maintenance progressed to the point where it was necessary to prepare, review, authorize, and perform the 1A residual heat removal service water return to service instructions. An on-shift reactor operator was assigned to complete this activity. The reactor operator retrieved a copy of the return to service instructions that were previously started by the clearance order writer. The reactor operator failed to note the special instructions for returning the residual heat removal heat exchanger flow reversing valves to service. In addition, the reactor operator failed to review the initial clearance order. The reactor operators actions were not in accordance with OP-MW-109-101 which required that non-carded steps used for configuration control be appropriately addressed as part of the return to service instructions. This resulted in a missed opportunity to identify the inappropriate configuration of the flow reversing valves upon the return to service.

Following several reviews, the unit supervisor approved the 1A residual heat removal service water return to service instructions and directed that the instructions be implemented. During the approval process, the unit supervisor noted the special instructions for the residual heat removal heat exchanger flow reversing valves and considered placing orange rings around the hand switches to alert control room personnel to the abnormal valve positions. However, the unit supervisor became distracted by a separate equipment issue and failed to take positive action to ensure that the special instructions were implemented.

Upon completing the return to service instructions, control room personnel began preparations to start the 1A residual heat removal service water pump. At this time, the breakers for the reversing valves were closed but the valves remained closed. A clearance order briefing was held with the operations personnel assigned to perform the in-plant manipulations. However, a formal brief of the control room manipulations was not held. During the first pump start, the control room operator secured the pump after one minute due to concerns that the system parameters were not changing as expected. Approximately 2 minutes later, the control room operator started the pump again. Within a short time another control room operator noticed that the pump was running deadheaded. The pump was immediately shut down and a proper discharge flow path was established. The licensee started the 1A pump for the third time and identified a leak which was believed to be coming from the room cooler. The licensee quickly shut down the 1A pump and started the 1B pump to confirm the location of the leak. Upon starting the 1B pump, an in-plant operator identified that the leak was on the common 1A residual heat removal service water loop discharge header. The cumulative effect of these combined weaknesses resulted in the licensee incurring an additional 24 hours of unavailability time to repair the header leak.

<u>Analysis</u>: The inspectors determined that the failure to ensure that the 1A residual heat removal service water return to service instructions were properly developed and implemented, that system return to service briefings were thorough, and that control board panel monitoring was adequate was more than minor because it led to operating the pump without an adequate flow path which had the potential to damage the pump and created a sizable leak in the residual heat removal service water pump vault. The inspectors also determined that this finding should be evaluated using the significance determination process because the finding was associated with the operability, availability and functionality of a mitigating system. The inspectors conducted a Phase 1 screening and determined that this issue was of very low safety significance because the leak did not result in a loss of safety function, did not result in a train loss of function for greater than the Technical Specification allowed outage time, and was not a potentially significant contributor to a seismic, flooding, or severe weather initiating event.

<u>Enforcement</u>: Technical Specification 5.4.1 requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978. Regulatory Guide 1.33, Revision 2, Appendix A, Section 1.c, requires procedures to be implemented for the licensee’s equipment control process (e.g., locking and tagging). Procedure OP-MW-109-101, “Clearance and Tagging,” was the licensee’s equipment control procedure. Procedure OP-MW-109-101, Step 7.1.9, required that all components manipulated during clearance activities be tracking via a clearance order tag, a non-carded step, or by a procedure to control overall system configuration. Contrary to the above, on October 7, 2004, operations personnel failed to properly implement Procedure OP-MW-109-101 to ensure that the position of the residual heat removal heat exchanger flow reversing valves was controlled by a clearance order tag, a non-carded step, or a procedure when returning the 1A residual heat removal service water system to service following maintenance. Because this violation was of very low safety significance, and because the issue was entered into the licensee’s corrective action program as Issue Report 261135, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-02)**. Corrective actions for this issue included providing training regarding the use of clearance order special instructions and non-carded steps, adding steps to the clearance and tagging procedure to ensure that non-carded steps were appropriately dispositioned during the final clear of the clearance order, and continuing the ongoing Operations Department’s human performance improvement plans to focus on items such as procedural adherence, briefings, and panel monitoring.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- QCOS 6600-20, “Diesel Generator Endurance and Margin/Full Load Reject/Hot Restart Test;”
- QCOS 5750-11, “Control Room Emergency Ventilation System Test;”
- QCOS 1600-07, “Reactor Coolant Leakage in the Drywell;” and
- QCOS 5750-09, “ECCS Room and DGCWP Cubicle Cooler Monthly Surveillance.”

The inspectors verified that the structures, systems, components, or barriers 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 was performed as written, the data was complete and met the requirements of the procedure, and the test equipment range and accuracy were consistent with the application by observing the performance of the activity. Following test completion, the inspectors conducted walkdowns of the associated areas to verify that test equipment had been removed and that the system or component was returned to its normal standby configuration. The reviews listed above represented the completion of four inspection samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed documentation for the temporary configuration change below:

- Engineering Change 352503 - Temporary Modification Repair for the Service Water Side of the Reactor Building Closed Cooling Water Main Header Service Water Leak on Main Header Side of 1-3999-685 Valve.

The inspectors assessed the acceptability of the temporary configuration change by comparing the 10 CFR 50.59 screening and/or evaluation information against the Updated Final Safety Analysis Report and Technical Specifications. The comparisons were 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 also reviewed issue reports initiated during or following the temporary modification installation to ensure that problems encountered during the installation were appropriately resolved. This review represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed an operations crew perform an emergency preparedness simulator drill on November 3. The scenario, Licensed Requalification Operating Exam Number 00-01, involved the failure of an electro-hydraulic regulator controller; the loss of essential service bus 13; a loss of condenser vacuum; and an unisolable leak outside of containment. The focus of the inspection activities was to note any weaknesses or deficiencies in the drill performance, ensure that the licensee's evaluators noted the same items, and verify that the licensee entered these items into its corrective action program. The inspectors placed emphasis on observations regarding event classification, notifications, timeliness, protective action recommendations, if needed, and any additional licensee expectations. This simulator observation represented the completion of one inspection sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous And Liquid Effluent Treatment And Monitoring Systems (71122.01)

.1 Inspection Planning

a. Inspection Scope

The inspectors reviewed the most current Radiological Effluent Release Report and current effluent release data to verify that the program was implemented as described in the Radiological Environmental Technical Specifications/Offsite Dose Calculation

Manual (RETS/ODCM) and the Updated Final Safety Analysis Report. The effluent report was also evaluated to determine if there were any significant changes to the Offsite Dose Calculation Manual or to the radioactive waste system design and operation. The inspectors verified that changes to the Offsite Dose Calculation Manual were technically justified, documented, and made in accordance with Regulatory Guide 1.109 and NUREG-0133. There were no significant modifications made to the radioactive waste system design and operation since the last inspection in this area. The inspectors evaluated the effluent report for anomalous results and verified that those results were adequately resolved.

The RETS/ODCM and Updated Final Safety Analysis Report were reviewed to identify the effluent radiation monitoring systems and associated flow measurement devices. Licensee records including condition reports, self-assessments, audits, and licensee event reports were reviewed to determine if there were any radiological effluent performance indicator occurrences or any unanticipated offsite releases of radioactive material for follow-up. The Updated Final Safety Analysis Report description of all radioactive waste systems was reviewed. These reviews represented one sample.

b. Findings

No findings of significance were identified.

.2 On-site Inspection

a. Inspection Scope

The inspectors walked down the major components of the gaseous and liquid release systems, including radiation and flow monitors, demineralizers, filters, tanks, and vessels. This was done to observe current system configuration with respect to the description in the Updated Final Safety Analysis Report, ongoing activities, and equipment material condition. This review represented one sample.

The inspectors reviewed system diagrams and observed accessible parts of the radioactive liquid waste processing and release systems to verify that appropriate treatment equipment was used, and that radioactive liquid waste was processed in accordance with procedural requirements. Liquid effluent release packages including projected doses to the public were reviewed to ensure that regulatory effluent release limits were not exceeded. The inspectors walked down accessible portions of the radioactive gaseous effluent processing and release systems and observed the collection and analysis of a gaseous effluent sample to verify that appropriate treatment equipment was used and that the radioactive gaseous effluent was processed and released in accordance with RETS/ODCM requirements. Radioactive gaseous effluent release data including the projected doses to members of the public was evaluated to ensure that regulatory effluent release limits were not exceeded. These reviews represented one sample.

The inspectors reviewed records of abnormal releases or releases made with inoperable effluent radiation monitors. The licensee's actions for these types of releases were evaluated to verify that adequate compensatory sampling and analyses were performed, and to ensure that an adequate defense-in-depth was maintained against an unmonitored, unanticipated release of radioactive material to the environment. This included projected radiological doses to members of the public. These reviews represented one sample.

The inspectors reviewed the licensee's technical justifications for changes made to the Offsite Dose Calculation Manual as well as to the liquid or gaseous radioactive waste system design, procedures, or operation including effluent monitoring and release controls since the last inspection. This was done to determine whether the changes affected the licensee's ability to maintain effluents as low as is reasonably achievable and whether changes made to monitoring instrumentation resulted in a non-representative monitoring of effluents. The inspectors also reviewed the licensee's offsite dose calculations and evaluated any significant changes in dose values reported in the annual report from those values reported the previous year. This included a review of the verification of the offsite dose calculation software. These reviews represented one sample.

The inspectors evaluated a selection of monthly, quarterly, and annual dose calculations to ensure that the licensee properly calculated the offsite dose from radiological effluent releases and to determine if any annual RETS/ODCM (i.e., Appendix I to 10 CFR Part 50) values were exceeded. This review represented one sample.

The inspectors reviewed air cleaning system surveillance test results to ensure that the system was operating within the licensee's acceptance criteria. The inspectors reviewed surveillance test results or methodology the licensee used to determine the stack and vent flow rates. The inspectors verified that the flow rates were consistent with RETS/ODCM or Updated Final Safety Analysis Report values. These reviews represented one sample.

The inspectors reviewed records of instrument calibrations performed since the last inspection for each point of discharge effluent radiation monitor and flow measurement device. There were no significant radwaste system modifications, and the current effluent radiation monitor alarm set point values were reviewed for agreement with RETS/ODCM requirements. The inspectors also reviewed calibration records of radiation measurement (i.e.,counting room) instrumentation associated with effluent monitoring and release activities. Radiation measurement instrumentation quality control data including corrective actions were evaluated to verify that the instrumentation was operating under statistical control and that any problems observed were addressed in a timely manner. These reviews represented one sample.

The inspectors reviewed the results of the interlaboratory comparison program to verify the quality of radioactive effluent sample analyses performed by the licensee. The inspectors reviewed the licensee's quality control evaluation of the interlaboratory comparison test results. No deficiencies were noted. In addition, the inspectors reviewed the results from the licensee's quality assurance audits to determine whether the licensee met the requirements of the RETS/ODCM. These reviews represented one sample.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors reviewed the licensee's self-assessments, audits, licensee event reports, and special reports related to the radioactive effluent treatment and monitoring program since the last inspection to determine if identified problems were entered into the corrective action program for resolution. The inspectors also verified that the licensee's self-assessment program identified and addressed repetitive deficiencies or significant individual deficiencies that were identified in problem identification and resolution.

The inspectors also reviewed corrective action reports from the radioactive effluent treatment and monitoring program, interviewed staff, and reviewed documents to determine if the following activities were being conducted in an effective and timely manner commensurate with their importance to safety and risk:

- 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 review represented one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Cornerstones: Mitigating Systems, Barrier Integrity, Occupational Radiation Safety, and Public Radiation Safety

.1 Reactor Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensees submittals for the performance indicators and 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 six performance indicators were reviewed:

Unit 1

- safety system unavailability for the high pressure coolant injection system,
- safety system unavailability for the reactor core isolation cooling system, and
- reactor coolant system specific activity.

Unit 2

- safety system unavailability for the high pressure coolant injection system,
- safety system unavailability for the reactor core isolation cooling system, and
- reactor coolant system specific activity.

With regards to the safety system unavailability performance indicators, the inspectors reviewed selected applicable conditions and data from logs, licensee event reports and issue reports from October 2003 through September 2004 for each performance indicator area specified above. The inspectors independently re-performed calculations where applicable. The inspectors compared that information to the information required for per each performance indicator definition in the guideline to ensure that the licensee reported the data accurately.

As part of the reactor coolant system specific activity performance indicator verification, the inspectors reviewed Chemistry Department records and selected isotopic analyses from October 2003 through October 2004 to verify that the greatest Dose Equivalent Iodine values obtained during those months corresponded with the values reported to the NRC. Additionally, the inspectors observed a chemistry technician obtain and perform a gamma isotopic analysis on reactor coolant samples to verify adherence with licensee procedures for the collection and analysis of reactor coolant.

b. Findings

No findings of significance were identified.

.2 Radiation Safety Strategic Area

a. Inspection Scope

The inspectors sampled the licensee's performance indicator submittals for the periods listed below. The inspectors used 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 performance indicators were reviewed:

- Occupational Exposure Control Effectiveness: Units 1 and 2

The inspectors reviewed the licensee's assessment of the performance indicator for occupational radiation safety, to determine if indicator related data was adequately assessed and reported during the previous four quarters. The inspectors compared the licensee's performance indicator data with the condition report database, reviewed radiological restricted area exit electronic dosimetry transaction records, and conducted walkdowns of accessible locked high radiation area entrances to verify the adequacy of controls in place for these areas. Data collection and analyses methods for performance indicators were discussed with licensee representatives to verify that there were no unaccounted for occurrences in the Occupational Radiation Safety performance indicator as defined in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." These reviews represented one sample.

- Radiological Environmental Technical Specification/Offsite Dose Calculation Manual Radiological Effluent Occurrences: Units 1 and 2

The inspectors reviewed data associated with the RETS/ODCM performance indicator to determine if the indicator was accurately assessed and reported. This review included the licensee's condition report database and selected condition reports generated over the previous four quarters, to identify any potential occurrences such as unmonitored, uncontrolled or improperly calculated effluent releases that may have impacted offsite dose. The inspectors also selectively reviewed gaseous and liquid effluent release data and the results of associated offsite dose calculations and quarterly performance indicator verification records generated over the previous four quarters. Data collection and analyses methods for performance indicators were discussed with licensee representatives to determine if the process was implemented consistent with industry guidance in Revision 2 of Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline." These reviews represented one sample.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Identification and Resolution of Problems

a. Inspection Scope

As discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's corrective action 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 included in the list of documents reviewed which is attached to this report.

b. Findings

No findings of significance were identified.

.2 Recognition and Reporting of Repetitive Main Steam Safety Valve Test Failures

a. Inspection Scope

The inspectors reviewed historical main steam safety valve test data against the acceptance criteria, interviewed engineering and regulatory assurance personnel, and reviewed historical corrective action documents to determine the licensee's reasons for not reporting multiple historic main steam safety valve as-found test failures.

b. Issues

In Inspection Report 2004002, the inspectors documented a concern regarding the licensee's ability to demonstrate that the main steam safety valves actuated within plus or minus one percent of the setpoint during as-found testing. This setpoint verification was used to demonstrate that the reactor pressure vessel remained protected from a potential overpressure condition. During the review, the licensee found that multiple main steam safety valves actuated outside of the acceptance criteria. However, the inspectors noted that none of these test failures had been reported to the USNRC in accordance with NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," Revision 2.

NUREG-1022 specifically states that Technical Specification surveillance testing failures, "should be assumed to occur at the time of the test unless there is firm evidence, based upon a review of relevant information, to indicate the discrepancies occurred earlier. However, the existence of similar discrepancies in multiple valves is an indication that the discrepancies may well have arisen over a period of time and the failure mode should be evaluated to make this determination. If the licensee determines that the failure mode occurred over a period of time, this condition would be reportable as any operation or condition prohibited by the licensee's Technical Specifications."

The inspectors searched the licensee's corrective action database and found that a condition report was written each time a main steam safety valve failed an as-found test. In addition, each condition report was evaluated by a member of the regulatory assurance department to ensure that the issue was not reportable to the USNRC. The inspectors reviewed each evaluation and determined that the licensee's evaluation focused on individual valve performance rather than the collective performance of all removed valves. For example, the licensee removed approximately five to nine main steam safety valves for testing during each refueling outage. Following the removal, the valves were sent to an independent test facility. Based upon the resources available at the test facility, weeks or months elapsed between valve tests. This resulted in the sporadic reporting of valve test failures to the licensee and contributed to the licensee's failure to evaluate the failures in the aggregate. The inspectors considered this to be a weakness in the licensee's ability to identify and correct problems.

The licensee entered this issue into their corrective action program as Condition Report 236177. Actions to address this issue included providing training to appropriate personnel regarding the comprehensive review of test results following testing of multiple pieces of equipment by an independent test facility. Additional actions regarding the technical aspects of this issue are described in Sections 4OA3.1 and 4OA5.1 of this report.

.3 Semi-Annual Trend Review

a. Inspection Scope

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

b. Findings

No findings or trends of significance were identified.

4OA3 Event Followup (71153)

.1 (Closed) Licensee Event Report 50-265/04-004-00: Main Steam Safety/Relief Valve As-Found Setpoint Outside of Technical Specification Allowed Value Due to Vibration

Introduction: A Green finding was identified when as-found testing on the Unit 2 main steam safety/relief valve (target rock valve) determined that the pressure setpoint had increased to 6.8 percent above the nameplate value. The increase in the pressure setpoint resulted in the valve's inability to actuate at the values assumed in the licensee's vessel overpressure and anticipated transient without scram analyses. This finding was considered a violation of regulatory requirements since the Technical Specifications require that the target rock valve actuate within plus or minus one percent of the nameplate value.

Description: On April 19, 2004, as-found testing of the Unit 2 main steam safety/relief valve was conducted by an independent testing facility. The results of the test demonstrated that the operating characteristics of the valve had changed considerably over the operating cycle. Prior to installing this valve in 2002, the licensee's testing showed that this valve would actuate within plus or minus 1 percent of the nameplate value. However, the results of the licensee's as-found testing showed that the pressure required to actuate this valve had increased by approximately 6 percent.

The licensee immediately began investigating the cause of the failed as-found test. During disassembly of the valve, individuals from the test facility, valve vendor representatives, and licensee personnel discovered a deep groove which had been worn into the bellows cap assembly. The licensee believed that the groove was caused by vibrations and internal movement of the pressure adjustment spring during normal plant operations. Over time, the groove became large enough to capture a coil of the adjustment spring which required extra force to be required to actuate the valve.

Analysis: The inspectors determined that the failure to ensure that the Unit 2 safety/relief valve maintained the ability to actuate within plus or minus 1 percent of the nameplate value was more than minor because if left uncorrected, this condition could lead to the degradation of other valves and put the licensee at risk for exceeding their vessel overpressure limits following an accident or an anticipated transient without scram. The inspectors also determined that this finding should be evaluated using the significance determination process because the finding was associated with the operability and function of a mitigating system. The inspectors conducted a Phase 1 screening and determined that a Phase 2 evaluation was needed as this finding impacted both the mitigating systems and barrier integrity cornerstones.

The inspectors used the Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station, Units 1 and 2, Revision 1, dated May 2, 2002, to complete the Phase 2 evaluation. The actual date of the valve failure could not be determined since this valve cannot be accessed or tested during reactor operation. Because of this, the fact that the valve had been installed since 2002, and the length and depth of the groove, the inspectors assumed that the exposure time was greater than 30 days. For each Significance Determination Process worksheet completed, the inspectors assumed that all remaining mitigating systems equipment was available. The inspectors allowed credit for recovery since the valve would have actuated once the pressure applied exceeded the increased actuation setpoint. Using these assumptions, the inspectors evaluated one core damage sequence on the anticipated transients without scram worksheet. The results of this sequence was eight points. Based on the counting rule, the overall increase in risk and safety was determined to be very low (Green).

Enforcement: Technical Specification 3.4.3 requires the safety function of all 9 safety valves to be operable in Modes 1, 2, and 3. To maintain operability, each safety valve must be able to actuate between plus and minus one percent of the nameplate value. Technical Specification Limiting Condition for Operation 3.4.3.A states that with one safety valve inoperable, the licensee must place the respective unit in Mode 3 within 12 hours and in Mode 4 within 36 hours. Contrary to the above, on April 19, 2004, the licensee discovered that the Unit 2 target rock valve would not have actuated within plus or minus one percent of the nameplate value during the previous operating cycle. Since the condition of the target rock valve was unknown to the licensee while Unit 2 was operating, actions taken to comply with the Technical Specification requirements were not taken. However, because this violation was of very low safety significance, and because the issue was entered into the licensee's corrective action program as Condition Report 215874, the issue is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000265/2004010-03)**. Corrective actions for this issue included installing a new safety/relief valve, performing additional testing to better understand the degradation mechanism, operating the Quad Cities units at pre-extended power uprate power levels, developing a modification to install better materials in the bellows cap area, and continuing the ongoing vibration assessments.

.2 (Closed) Licensee Event Report 50-254/04-002-00: Technical Specification Allowable Value Exceeded for Low Pressure Coolant Injection Loop Select Reactor Low Pressure Switches

Introduction: A Green finding was self-revealed when testing on two of the Unit 1 low pressure coolant injection loop select low pressure switches showed that the pressure setpoint had drifted above the Technical Specification value. The drift occurred due to the implementation of an unapproved and undocumented switch modification which caused an alignment issue between the pressure switches' bourdon tube actuating plate and micro-switch plunger. This finding was considered a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," due to the failure to establish measures to ensure the applicable regulatory requirements and the design basis were correctly translated into specifications, drawings, procedures, and instructions.

Description: On July 30, 2004, maintenance personnel performed surveillance test QCIS 0200-11, "Reactor Low Pressure Calibration and Functional Test." The results of this test showed that the setpoint for two of the low pressure coolant injection loop select low pressure switches was above the Technical Specification value. Once identified, the switches were adjusted to within the appropriate Technical Specification tolerance range.

The licensee performed a historical review and determined that the switches were previously modified by removing one of the two micro-switches that were in contact with the bourdon tube actuating plate. No documentation was found to support the modification; however, based on the review of various procedural and testing documents the modification was made sometime before 1996. In addition, in 2001, the pressure switches' Technical Specification required functional and calibration testing frequency was changed from quarterly to biannually due to the implementation of improved technical specifications. The increased time between testing allowed the switch to eventually drift beyond it's appropriate range. The inspectors verified that future calibration and functional testing frequency was evaluated and rescheduled to a quarterly frequency until the pressure switches were replaced or modified to their original design.

Analysis: The inspectors determined that the failure to evaluate and document the modification to the Unit 1 low pressure coolant injection loop select low pressure switches was more than minor because if left uncorrected, this condition could lead to further switch drifting and failure of the low pressure coolant injection system to perform its safety function. The inspectors also determined that the finding should be evaluated using the significance determination process because the finding was associated with the function of a mitigating system. The inspectors conducted a Phase 1 screening and determined that the issue screened as Green, in part, because the finding did not represent an actual loss of safety function for the low pressure coolant injection system.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. The design basis requirement contained in Technical Specifications required the low pressure coolant injection loop select low pressure switches to actuate between 868 and 891 psig.

Contrary to the above, since at least 1996, the licensee has failed to assure that the design basis requirement for the low pressure coolant injection loop select low pressure switches to actuate at the Technical Specification required value was correctly translated into a previous modification. However, because this violation was of very low safety significance, and because the issue was entered into the licensee's corrective action program as Issue Reports 275287and 240494, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-04)**. The licensee completed an operability determination and concluded that the installed switches were in an operable but degraded condition. The licensee adjusted the calibration and functional testing frequency to quarterly to minimize the amount of drift over time and to ensure that the switches would operate within the Technical Specification value. The licensee is planning to replace the pressure switches, or return the installed pressure switches to their original design, during the next refueling outage.

.3 (Closed) Licensee Event Report 50-254/04-003-00: Control Room Emergency Ventilation Test Failure due to Deficient Modification to Hatch Covers

Introduction: One Green finding and a Non-Cited Violation of Technical Specification 3.7.4 were identified due to the licensee's failure to have a procedure appropriate to the circumstance for testing the control room emergency ventilation system. The inadequate procedure, in conjunction with a deficient hatch cover modification, resulted in the licensee being unable to demonstrate that the control room emergency ventilation system could maintain the control room emergency zone at greater than 1/8 of an inch differential pressure at a flow rate of 2000 standard cubic feet per minute.

Description: While performing surveillance testing on the control room emergency ventilation system on October 8, operations personnel identified that the acceptance criteria which required the system to maintain the control room emergency zone at greater than 1/8 of an inch differential pressure at a flow rate of 2000 standard cubic feet per minute had not been met. A review of prior surveillance tests conducted in 2000 and 2002 also concluded that this acceptance criteria had not been met.

The licensee entered Technical Specification Surveillance Requirement 3.0.3 which provided an additional 24 hours to demonstrate that the control room emergency ventilation system could meet the acceptance criteria stated above. During this 24 hour time frame, the licensee discovered two hatch covers between the auxiliary electric equipment room and the cable tunnels which were not completely sealed. The licensee determined that the incomplete sealing was caused by a 1999 modification which installed counterweights to the hatch covers. These counterweights decreased the weight of the covers on the seal which allowed a slight bow in the hatch covers to affect the overall seal integrity.

The licensee conducted a root cause analysis for this event and determined that the failure to perform an adequate control room emergency ventilation test in 2000 and 2002 was caused by an inadequate 1998 procedure change. Specifically, the procedure change review did not identify that the Technical Specification required flow verification step was being inadvertently removed from the procedure. The licensee's surveillance procedure format also contributed to the failure to identify this issue earlier as the acceptance criteria were located at the beginning of the procedure rather than near the signature block which was signed to verify that the surveillance test was performed satisfactorily.

Analysis: The inspectors determined that the failure to have a procedure which adequately tested the control room emergency ventilation system, and have hatch covers which provided an adequate seal, was more than minor because if left uncorrected, this condition could lead to further degradation in the system's ability to pressurize the control room emergency zone following a design basis event. The inspectors also determined that the finding should be evaluated using the significance determination process because the finding was associated with the integrity of the control room envelope. The inspectors conducted a Phase 1 screening and determined that the issue screened as Green since this failure only represented a degradation of the radiological barrier provided for the control room. The ability to protect control room personnel from smoke and toxic gases was not impacted.

Enforcement: Technical Specification 3.7.4 required that the control room emergency ventilation system be operable when a reactor was operating in Modes 1, 2, or 3. To maintain operability Technical Specification Surveillance Requirement 3.7.4.4 required the licensee to verify that the control room emergency ventilation system can maintain a positive pressure of greater than 1/8 of an inch of water relative to the adjacent areas during the pressurization mode of operation at a flow rate of less than or equal to 2000 standard cubic feet per minute. If the control room emergency ventilation system becomes inoperable, the Technical Specifications require that the system be returned to service within days or that the licensee place the respective reactor in Mode 3 within 12 hours and in Mode 4 within 36 hours. Contrary to the above, the licensee had failed to demonstrate that the control room emergency ventilation system maintained a positive pressure of greater than 1/8 of an inch of water relative to the adjacent areas during the pressurization mode of operation at a flow rate of less than or equal to 2000 standard cubic feet per minute since 1998. Because this condition was not known by the licensee, actions were not taken to shut down the respective reactor. However, because this violation was of very low safety significance, and because the issue was entered into the licensee's corrective action program as Issue Report 261523, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-05; 05000265/2004010-05)**. Corrective actions for this issue included providing additional sealing material to the hatch covers and revising the control room emergency ventilation surveillance procedures to ensure that the Technical Specifications continue to be met.

4OA4 Cross-Cutting Aspects of Findings

.1 A finding described in Section 1R19 of this report had, as its primary cause, multiple human performance deficiencies, in that, operations personnel failed to follow the licensee's locking and tagging procedure when developing system return to service instructions, used unverified assumptions when developing return to service instructions, held weak briefings which did not fully describe all system return to service actions, and performed deficient control board panel monitoring. This resulted in operations personnel starting the 1A residual heat removal service water pump without a discharge path. This created a significant leak in the service water pump vault and required an additional 24 hours of system unavailability time to repair.

.2 An observation described in Section 4OA2.1 of this report had, as its primary cause, a problem identification and resolution deficiency. Specifically, engineering and regulatory assurance personnel failed to consider multiple failures of the main steam safety valves to actuate in the aggregate and develop corrective actions to address the condition. This failure also resulted in a missed opportunity to report this condition to the NRC as discussed in NUREG-1022.

4OA5 Other Activities

.1 (Closed) Unresolved Item 50-254/2004002-01;50-265/2004002-01: Ability of Main Steam Safety Valves to Meet Technical Specification Requirements.

Introduction: A Green finding was identified due to historic inability of all nine main steam safety valves to actuate within plus or minus one percent of the nameplate value during as-found testing. This finding was considered a violation of regulatory requirements since the Technical Specifications require that the main steam safety valves actuate at plus or minus one percent of the nameplate value. The inspectors also identified an additional concern in that the licensee had not reported the previous main steam safety valve test failures or the Technical Specification noncompliances to the NRC (see Section 4OA2.1 of this report).

Description: During the review of a Technical Specification amendment request for Dresden Station, members of 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. 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 at least two or more valves failed to meet the Technical Specification Surveillance Requirement during each of the last six refueling outages.

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 electromatic relief valves was inoperable. At the time this issue was identified, neither unit was operating at full thermal power and all of the electromatic relief valves were operable. However, the inspectors found that Unit 1 had operated at full thermal power levels during the summer of 2003. In addition, one of the electromatic relief valves may have been inoperable during this time (see Section 1R20 of Inspection Report 50-254/2003013; 50-265/2003013). The inspectors had additional discussions with engineering personnel to address the Unit 1 operating conditions. The licensee's engineering department performed another analysis which demonstrated that the Unit 1 reactor vessel was adequately protected from an overpressure condition even though a portion of the equipment credited in the initial analysis was not fully functional. The inspectors reviewed this analysis by verifying the analysis assumptions and calculations and ensuring that the worst case pressure was less than the vessel overpressure limits.

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

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

Enforcement: Technical Specification 3.4.3 requires the safety function of all 9 main steam safety valves to be operable in Modes 1, 2, and 3. To maintain operability, each safety valve must be able to actuate between plus and minus one percent of the nameplate value. Technical Specification Limiting Condition for Operation 3.4.3.A states that with one safety valve inoperable, the licensee must place the respective unit in Mode 3 within 12 hours and in Mode 4 within 36 hours. Contrary to the above, on several occasions over the last 4 years, the licensee failed to ensure that the main steam safety valves would continue to actuate within plus or minus one percent of the nameplate value during the operating cycle. Since the condition of the valves was unknown to the licensee during the operating cycle, actions were not taken to comply with the Technical Specification requirements. However, because this violation was of very low safety significance, and because the issue was entered into the licensee's corrective action program as Condition Report 238434, the issue is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-06; 05000265/2004010-06)**. Corrective actions for this issue included installing new main steam safety valves, submitting a license amendment to change the main steam safety valve operating tolerances, and revising a previously issued Licensee Event Report to report the previous failures.

.2 (Closed) Unresolved Item 05000254/2004004-02; 05000265/2004004-02: Reactor Core Isolation Cooling Torus Suction Valve.

a. Inspection Scope

Unresolved Item 05000254/2004004-02; 05000265/2004004-02 identified that the design of the reactor core isolation cooling system did not provide adequate capability to isolate the safety-related torus from the non-safety related/non-seismic portions of the reactor core isolation cooling system under all conditions. Based on the absence of design calculations, the inspectors were unable to evaluate the effect on the emergency core cooling systems operation during a seismic event. This item was left unresolved pending licensee preparation of calculations to ensure the reactor core isolation cooling piping would remain intact following a seismic event. In followup to the unresolved item, the inspectors reviewed the licensee's operability calculations and other corrective actions.

b. Findings

Introduction: The inspectors identified a finding involving a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control," having very low safety significance (Green). Specifically, the design of the reactor core isolation cooling system did not provide adequate capability to isolate the safety-related torus from the non-safety related/non-seismic portions of the reactor core isolation cooling system under all conditions. As part of resolving unresolved item 05000254/2004004-02; 05000265/2004004-02, the licensee performed analyses, implemented compensatory procedure guidance, and initiated plans to modify the reactor core isolation cooling torus suction isolation valves’ control logic to allow the valves to be closed from the control room.

Description: During the 2004 safety system design and performance capability inspection, the NRC identified that the control logic for the reactor core isolation cooling torus suction valves, 1(2)-1301-25 and 1(2)-1301-26, would not allow the operators to override the automatic transfer signal and manually close these valves from the control room in the event of a failure of the non-seismic reactor core isolation cooling piping during a seismic event. These motor-operated valves normally provide isolation of the safety-related flow path from the torus to the reactor core isolation cooling pump suction header. The reactor core isolation cooling normal water supply was from the contaminated condensate storage tanks. The torus suction valves were designed to open in the event of either low contaminated condensate storage tank level or high torus level, providing automatic transfer of the reactor core isolation cooling pump suction source from the contaminated condensate storage tank to the torus. This automatic transfer was designed to occur whether the reactor core isolation cooling pump was operating or not. If the operators attempted to manually close the valves from the control room, the valves would automatically reopen based on the valves’ control logic when the valves’ control switch was released.

The inspectors reviewed QDC-1300-—1388, “Operability Evaluation of RCIC Unit 1 Pump Discharge Piping for Seismic Loading Conditions,” Revision 0, and QDC-1300-—1389, “Operability Evaluation of RCIC Unit 2 Pump Discharge Piping for Seismic Loading Conditions,” Revision 0, and identified concerns with some of the methodologies and assumptions used to show the piping would not fail following a seismic event. These concerns included:

C The analyses established a system design temperature of 140 degrees Fahrenheit (EF) based on General Electric Specification 21A5822AF, “RCIC Pump Data Sheet,” Revision 1. Since this temperature was less than 150EF, no evaluation for the effect of piping thermal expansion was performed. However, R-4441, “General Work Specification,” Revision 8, indicated a design temperature of 325EF.

C The stress intensification factors for socket joint fillet welds were effectively decreased to 1.3 in the computer analyses. The American Society of Mechanical Engineers Code specified an stress intensification factors of 2.1 for fillet welds. American Society of Mechanical Engineers also applied a 0.75 factor in the determination of piping stress (effective stress intensification factors = 0.75 * 2.1 = 1.575).

C The u-bolt allowable loads were taken from commercial grade catalogue PH-2002, Grinnell Fig. 137, without any supporting documentation. The applicable allowable Grinnell u-bolt loads for nuclear applications were listed in Grinnell certified Design Report Summary, Fig. 137N (Service Level D loads were applicable for operability evaluations).

C Calculation QDC-1300-—1389 stated that the u-bolt at pipe support node NP-1070 was attached to Unistrut. However, after being questioned by the inspectors, a subsequent walkdown identified the u-bolt was attached to a single angle member.

C Non-conservative weld allowables were potentially used in the analyses as the licensee assumed at least 70 ksi [thousand pounds per square inch] weld rod was used to fabricate the reactor core isolation cooling pump discharge piping supports without any supporting documentation.

The licensee generated Issue Report 241279 to document the different reactor core isolation cooling system design temperatures in R-4411 and General Electric Specification 21A5822AF. In addition, Issue Report 272067 was initiated to document a lesson learned for the engineering organization concerning issues identified by the inspectors with the initial calculations. The above calculations were subsequently revised to incorporate the inspectors' comments. The inspectors reviewed the revised calculations and concluded that the calculations, from a historical perspective, demonstrated that the reactor core isolation cooling pump discharge piping would not have failed during a seismic event and would have been considered operable. The calculations, however, only used operability acceptance criteria, such that the piping in question would not meet the design requirements for seismic Class I piping and required additional actions to resolve the issue.

Operability Evaluation 223815-08, which was previously performed to address continued system operability, implemented an action item to revise operating procedures to provide guidance to the operator to override the automatic transfer signal and close these valves if required. This action would require the operators to place finger blocks in relays in the auxiliary electrical equipment room. The action item was completed on May 28, 2004. Since this action was considered an operator work around by the operations department, engineering changes EC0000350636, "Install a New Key-Lock Switch in the Auto Open Logic for RCIC Torus Suction Valve 1-1201-25 & 26," and EC0000350637, "Install a New Key-Lock Switch in the Auto Open Logic for RCIC Torus Suction Valve 2-1201-25 & 26," were initiated to address a permanent resolution to this concern.

<u>Analysis</u>: The inspectors considered the failure to maintain remote manual capability for the torus suction isolation valve to be a performance deficiency. The inspectors

determined that the finding was more than minor in accordance with Inspection Manual Chapter 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Disposition Screening,” because it was associated with the attributes of design control, which affected the mitigating systems cornerstone objective of ensuring the availability and reliability of the emergency core cooling systems to respond to initiating events to prevent undesirable consequences. In addition, since this issue affected containment isolation valves, there was a potential impact on the barrier integrity cornerstone objective of maintaining the functionality of containment. However, the issue was determined to not represent an actual open pathway in the physical integrity of the reactor containment, such that it was only addressed as affecting the mitigating systems cornerstone.

The inspectors evaluated the finding using Inspection Manual Chapter 0609, “Significance Determination Process,” Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” Phase 1 screening, and determined that the finding screened as Green because it was not a design issue resulting in loss of function per Generic Letter 91-18.

Enforcement: 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures be established to assure that applicable regulatory requirements and the design basis are correctly translated into specifications, drawings, procedures, and instructions. This design basis requirement to maintain remote manual containment isolation capability was documented in the NUREG-0737, Item II.K.3.22, “Safety Evaluation,” dated December 29, 1983.

Contrary to the above, as of May 28, 2004, the modification to the control logic for valves 1(2)-1301-25 did not correctly implement the design basis requirement to maintain remote manual containment isolation capability. However, because this violation was of very low safety significance and because the issue was entered into the licensee’s corrective action program as Issue Report 223815, the issue is being treated as a Non-Cited Violation, consistent with Section VI.A.1 of the NRC Enforcement Policy **(NCV 05000254/2004010-07; 05000265/2004010-07)**. As part of its corrective actions, the licensee implemented proceduralized manual operator actions to ensure the remote manual containment isolation capability was maintained until plans to modify the valves control logic could be implemented.

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 January 4, 2005. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The radioactive gaseous and liquid effluent treatment and monitoring systems, and performance indicator verifications for reactor coolant system activity, occupational exposure control effectiveness, and RETS/ODCM radiological effluents, with Mr. T. Tulon on November 18, 2004.

- Unresolved item 05000254/2004004-02; 05000265/2004004-02 with Mr. W. Beck on December 16, 2004.

- Annual NRC Licensed Operator Requalification examination with Mr. D. Snook, Acting Operator Training Manager, on December 28, 2004, via telephone.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee
T. Tulon, Site Vice President
R. Gideon, Plant Manager
R. Armitage, Training Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
G. Boerschig, Engineering Manager
T. Hanley, Maintenance Manager
D. Hieggelke, Nuclear Oversight Manager
S. Kirkland, Chemistry Supervisor
D. McCullough, Chemistry
V. Neels, Chemistry/Environ/Radwaste Manager
M. Perito, Operations Manager
D. Snook, Acting Operator Training Manager

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

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000254/2004010-01; 05000265/2004010-01	NCV	Failure of Safety Valve Discharge Line Flanges to Meet Code Requirements (Section 1R15)
05000254/2004010-02	NCV	Failure to Follow Locking and Tagging Procedure While Developing System Return to Service Instructions Contributes to Leak Creation During Post Maintenance Testing (Section 1R19)
05000265/2004010-03	NCV	Failure of Unit 2 Target Rock Valve to Meet Technical Specification Surveillance Requirements of Technical Specification 3.4.3 (Section 4OA3.1)
05000254/2004010-04	NCV	Technical Specification Allowable Value Exceeded for Low Pressure Coolant Injection Loop Select Reactor Low Pressure Switches (Section 4OA3.2)

05000254/2004010-05; 05000265/2004010-05	NCV	Control Room Emergency Ventilation Test Failure due to Inadequate Procedure and Deficient Modification to Hatch Covers (Section 4OA3.3)
05000254/2004010-06; 05000265/2004010-06	NCV	Historical Failure of Main Steam Safety Valves to Meet Technical Specification Surveillance Requirements (Section 4OA5.1)
05000254/2004010-07; 05000265/2004010-07	NCV	Failure to Provide Adequate Capability to Isolate the Safety Related Torus from the Non-Seismic Portions of the Reactor Core Isolation Cooling System (Section 4OA5.2)

Closed

05000254/04-002-00	LER	Technical Specification Allowable Value Exceeded for Low Pressure Coolant Injection Loop Select Reactor Low Pressure Switches
05000254/04-003-00	LER	Control Room Emergency Ventilation Test Failure due to Deficient Modification to Hatch Covers
05000265/04-004-00	LER	Main Steam Safety/Relief Valve As-Found Setpoint Outside of Technical Specification Allowed Value Due to Vibration
05000254/2004002-01; 05000265/2004002-01	URI	Ability of Main Steam Safety Valves to Meet Technical Specification Requirements
05000254/2004004-02; 05000265/2004004-02	URI	Failure to Provide Adequate Capability to Isolate the Safety Related Torus from the Non-Seismic Portions of the Reactor Core Isolation Cooling System
05000254/2004010-01; 05000265/2004010-01	NCV	Failure of Safety Valve Discharge Line Flanges to Meet Code Requirements
05000254/2004010-02	NCV	Failure to Follow Locking and Tagging Procedure While Developing System Return to Service Instructions Contributes to Leak Creation During Post Maintenance Testing
05000265/2004010-03	NCV	Failure of Unit 2 Target Rock Valve to Meet Technical Specification Surveillance Requirements of Technical Specification 3.4.3

05000254/2004010-04	NCV	Technical Specification Allowable Value Exceeded for Low Pressure Coolant Injection Loop Select Reactor Low Pressure Switches
05000254/2004010-05; 05000265/2004010-05	NCV	Control Room Emergency Ventilation Test Failure due to Inadequate Procedure and Deficient Modification to Hatch Covers
05000254/2004010-06; 05000265/2004010-06	NCV	Historical Failure of Main Steam Safety Valves to Meet Technical Specification Surveillance Requirements
05000254/2004010-07; 05000265/2004010-07	NCV	Failure to Provide Adequate Capability to Isolate the Safety Related Torus from the Non-Seismic Portions of the Reactor Core Isolation Cooling System

Discussed

None.

LIST OF DOCUMENTS REVIEWED

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

1R01 Adverse Weather

Issue Report 275411; CCST Heater Breaker Tripped; dated November 20, 2004
QCOS 3300-02; CCST and CST Heater Testing; Revision 2
Work Order 689183; Winterizing Checklist; dated November 24, 2004
QCOP 0010-01; Winterizing Checklist; Revisions 26, 27, and 28

1R04 Equipment Alignment

QOM 2-1000-02; Unit 2 RHR Valve Check List (North RHR Room); Revision 12
QOM 2-1000-08; Unit 2 RHR Valve Check List (Outside the 2A RHR Corner Room); Revision 4
QOM 1-1001-04; Unit 1 RHR Valve Checklist (South RHR Room); Revision 10;
QOM 1-1000-09; Unit 1 RHR Valve Checklist (Outside the 1B RHR Corner Room): Revision 5
QCOP 1000-02; RHR System Preparation for Standby Operation; Revision 22

1R05 Fire Protection

National Fire Protection Code
OP-MW-201-007; Fire Watch Inspection Log for Fire Door 144; dated October 1, 2004
QCMMS 4100-61; Fire Door Inspection; Revision 10
Engineering Change 351618; Engineering Evaluation of Fire Door 144; Revision 0
Issue Report 257837; Fire Door 144 Between the 1A and 2B RHR Rooms may not Close; dated September 27, 2004

1R06 Flood Protection Measures

Quad Cities Station Individual Plant Examination Submittal Report; Section 4.4.4.; Internal Flooding Analysis; December 1993
Mechanical Drawing —132; Reactor Building Piping Plan Elevation 554 feet; Revision H
Issue Report 223815; Potential to Drain the Torus on Failure of RCIC Line; dated May 26, 2004
QCOP 1300-06; Defeating RCIC Suction Automatic Transfer to Torus; Revision 0
QCOA 1600-05; Leak in Torus; Revision 7
Work Order 723971; 1A Core Spray Room Drain Valve Failed Surveillance Test; August 6, 2004
QCOS 0020-04; Reactor Building Floor Drain Sump Ball Valve Leakage Testing; Revision 1

Issue Report 255378; Potential Open Flood Path Between 2A and 2B/C Residual Heat Removal Service Water Vaults; dated September 21, 2004
Issue Report 275050; Error in Evaluation for IR 255378 Required; dated November 19, 2004
Engineering Change 351529; Need to Evaluate Effect of Removing Sub Door from 2A Residual Heat Removal Service Water Vault; dated November 18, 2004

1R11 Licensed Operator Requalification

QCGP 2-3; Reactor Scram; Revision 51
QGA 100; RPV Control; Revision 7
QGA 101; RPV Control (ATWS); Revision 10
QGA 200; Primary Containment Control; Revision 8
QGA 500-1; RPV Blowdown; Revision 11
QCOS 5750-06; Toxic Gas Monitoring Channel/System Inoperable Outage Report; Revision 18
QCOA 0201-01; Increasing Drywell Pressure; Revision 16
QOA 5750-13; Toxic Air or Smoke in the Control Room; Revision 16

1R12 Maintenance Effectiveness

Condition Report 150867; Corrective Maintenance Unexpected - Motor Driven Pump Breaker; dated February 5, 2003
Condition Report 206872; Snubber Hardware Discrepancies Identified During Q2R17; dated March 7, 2004
Condition Report 208292; ISI Support 1404-—104.1 Found With Discrepancies; dated March 14, 2004
Issue Report 237166; Core Spray Keep Fill Hi/Lo Alarm Switch; dated July 19, 2004
Issue Report 266427; Pressure Switch 1-1469 Out of Tolerance; dated October 23, 2004
Condition Report 209547; Valve 2-1402-24B Will Not Close From the Control Room; dated March 19, 2004
MA-AA-723-325; Molded Case Circuit Breaker Testing; Revision 1
National Electrical Manufacturers Association Standards Publication AB 4-2003; Guidelines for Inspection and Preventive Maintenance of Molded Case Circuit Breakers Used in Commercial and Industrial Applications
Electric Power Research Institute NR-7410-V3; Molded Case Circuit Breaker Maintenance and Application Guide; Revision 1
QCEMS 0250-11; 480/208 VAC Motor Control Center Maintenance and Surveillance; Revision 40
Condition Report 138575; Failed Breaker; dated January 8, 2003
Condition Report 143005; ECCS Keep Fill Pump Stopped Operating; dated February 5, 2003
Condition Report 146047; Circuit Breaker Failed Trip Test; dated February 24, 2003
Condition Report 151947; Molded Case Breaker Failed Testing; dated April 1, 2003
Condition Report 155084; MCC Circuit Breaker Failed Trip Test; dated April 19, 2003

Condition Report 163876; Molded Case Breaker Failed Trip Test; dated June 17, 2003
Condition Report 166649; MCC 17-6 Breaker Failed As Found LTD Trip Time; dated July 8, 2003
Condition Report 170995; Breaker Failed Trip Test; dated August 7, 2003
Condition Report 171144; Breaker Failed Trip Test; dated August 11, 2003
Condition Report 200978; Molded Case Circuit Breaker Failed Trip Test; dated February 9, 2004
Condition Report 201875; Breaker Failed Trip Testing; dated February 16, 2004
Condition Report 208670; Core Spray Minimum Flow Valve MO 1-1402-38A Tripped Thermals; dated March 16, 2004
Condition Report 215202; Failure Analysis of GE AK-25 Breaker N053; dated April 15, 2004
Condition Report 227964; Loss of Power to MCC 29-1-1; dated June 11, 2004
Issue Report 234766; MCC Molded Case Circuit Breaker Failed Trip Test; dated July 8, 2004
Issue Report 235677; Failed Breaker on MCC 27-1 Cubicle H-1 Failed A Phase Instantaneous Trip; dated July 13, 2004
NRC Bulletin 88-10; Nonconforming Molded Case Circuit Breakers; dated November 22, 1988
NRC Bulletin 88-10, Supplement 1; Nonconforming Molded Case Circuit Breakers; dated August 3, 1989
NRC Information Notice 88-46, Supplement 4; Licensee Report of Defective Refurbished Circuit Breakers; dated September 11, 1989
NRC Information Notice 92-51, Supplement 1; Misapplication and Inadequate Testing of Molded Case Circuit Breakers; dated April 11, 1994
NRC Information Notice 93-64; Periodic Testing and Preventive Maintenance of Molded Case Circuit Breakers; dated August 12, 1993
NRC Information Notice 96-24; Preconditioning of Molded Case Circuit Breakers Before Surveillance Testing; dated April 25, 1996

1R13 Maintenance Risk Assessment and Emergent Work

Daily Production Schedules; dated October 4 -10, 2004
Work Week Risk Assessment for Week of October 4, 2004

1R15 Operability Evaluations

ANSI B31.1; Power Piping Code; dated 1967
ASME Section VIII of the Boiler and Pressure Vessel Code
USAS B16.5 Code; “Steel Pipe Flanges and Flanged Fittings; dated 1968
Engineering Change 345846; Evaluate the Impact of the Main Steam Safety Relief Valve Discharge Line Flange Ratings Being Lower than Maximum Pressure; dated unknown

1R16 Operator Workarounds

Issue Report 276520; Dates to Issue Temporary Modification Engineering Changes for Operator Workarounds Extended from Original; dated November 24, 2004
Operator Burden Review; dated October 2004
OP-AA-102-103; Operator Work-Around Program; Revision 1
QCOA 1600-05; Leak In Torus; Revision 7
QCOP 1300-06; Defeating RCIC Suction Automatic Transfer to Torus; Revision 0
QCOA 0010-12; Fire/Explosion; Revision 25
QCOP 4100-16; Manually Filling the Diesel Fire Pump Day Tank; Revision 10
List of Operator Workarounds and Challenges; dated November 17, 2004

1R19 Post Maintenance Testing

Work Order 756290-01; Troubleshoot 480 Volt Breaker for MOV1-1001-26A - Failure of Relay Contacts to Open; dated November 22, 2004
Root Cause Analysis for Issue Report 261135; Improper Valve Lineup of 1A RHRSW System; dated November 5, 2004

1R22 Surveillance Testing

Work Order 599276; Diesel Generator Endurance Margin/Full Load Reject/Hot Start; October 14, 2004
Predefine 34614; Unit 1 Drywell Floor Drain Sump Flow Calibration
Predefine 36281; Unit 1 Drywell Equipment Drain Sump Flow Calibration
Predefine 34615; Unit 2 Drywell Floor Drain Sump Flow Calibration
Predefine 36282; Unit 2 Drywell Equipment Drain Sump Flow Calibration
QIP 2000-02; Drywell Equipment Drain Flow Calibration; Revision 6
VETI C0066; Instruction Manual for Rosemount 1151DP Transmitter, Revision AA
QCIS 2000-02; Drywell Floor Drain Flow Indication Calibration; Revision 6
Issue Report 280736; RHR Room Cooler Flow Indicator Reading Low; December 9, 2004
Work Order 754880; ECCS Room Cooler and DGCWP Cubicle Monthly Testing; dated December 9, 2004

1R23 Temporary Modifications

Issue Report 275076; Unisolable Service Water Leak on 2" Line Unit 1 Reactor Building; dated November 19, 2004
Issue Report 276252; Permanently Repair Leaking 2" Pipe Nipple in High Point Vent; dated November 23, 2004
Engineering Change 352503; Temporary Modification Repair for the Service Water Side of the Reactor Building Closed Cooling Water Main Header Service Water Leak on Main Header Side of 1-3999-685 Valve; Revision 0
Engineering Change 352503; Temporary Modification Repair for the Service Water Side of the Reactor Building Closed Cooling Water Main Header Service Water Leak on Main Header Side of 1-3999-685 Valve; Revision 1

1EP6 Drill Evaluation

QGA 100; RPV Control; Revision 7
QGA 200; Primary Containment Control; Revision 8
QGA 300; Secondary Containment Control; Revision 11
QGA 500-1; RPV Blowdown; Revision 11
QCOA 0010-12; Fire/Explosion; Revision 25
QCOA 0400-02; Core Instabilities; Revision 4
QCOA 1600-05; Leak in Torus; Revision 7
QCOA 3300-01; Loss of Condensate Pump; Revision 16
EP-AA-111; Emergency Classification and Protective Action Recommendations; Revision 8
EP-AA-112-100; Control Room Operations; Revision 6
EP-AA-113; Personnel Protective Actions; Revision 5
EP-AA-114; Notifications; Revision 5
QCOA 4400-01; Loss of All Circulating Water Pumps; Revision 6
QCOA 4400-04; Reactor Operation With Only One Circulating Water Pump Available; Revision 14
QCOA 5650-01; Malfunction of the EHC Pressure Control System; Revision 13

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

CY-QC-130-403; Main Chimney SPING/Victoreen Calibration; dated June 17, 2004
CY-QC-130-402; MC HR Noble Gas Monitor Calibration; dated June 24, 2004
QCIS 1700-07; Reactor Building U1 Vent/Fuel Pool Rad Monitor Cal/Function Test; dated September 1, 2004
QCCP 0800-05; CTP-477 HP GE Calibration; dated September 24, 2004
QCCP 0800-05; DTP-787 HP GE Calibration; dated September 24, 2004
HP Germanium Detector Data; FWHM at 1332 KeV
QCCP 0800-11; LLD Determination, Detector ATP-131; dated December 22, 2003
QCTS 0430-03; SGTS In-place Charcoal Adsorber Leak Test; dated March 11, 2003
QCTS 0430-02; SGTS In-place DOP Leak Test of HEPA Filters; dated March 11, 2003
QCTS 0430-05; SGTS Removal Of Charcoal Adsorber Canister; dated March 10, 2003
NOSA-QDC-04-04; Chemistry Radwaste, PCP Audit; dated May 5, 2004
LS-AA-126-1005; Self-assessment: Radwaste, Transportation; dated August 5, 2004
RWP 1000 3276; Chemistry Surveillance; Revision 0
Reactor Coolant Units 1 and 2 - Gamma Isotopic Date; dated November 17, 2004
Quad Cities Radiological Environmental Operating Report (2003); dated May 14, 2004
Quad Cities Radiological Effluent Report (2003); dated April 30, 2004
Focus Area Self-assessment, Radwaste Process Vendor; dated October 15, 2003
NOSPA-QC-04-4Q; NOS Review Of RP and Chemistry; dated November 5, 2004
AR258151; Radioactive Liquid and Gaseous Effluents Check-in Results; dated September 29, 2004
AR217783; NOS ID Finding - Unresolved Radwaste Issues; dated April 29, 2004
AR235454; Dose Due To Iodine And Particulates >2 Percent Of Limit; dated July 9, 2004

AR228697; Unexpected Loss Of MC Sample Flow During Maintenance; dated June 14, 2004
AR216081; 1A RHR Heat Exchanger SW Activity Higher Then Expected; dated April 15, 2004
AR215666; ODCM Gaseous LLDs Based On Non-conservative Sample Volumes; dated April 19, 2004
AR236348; Abnormal Liquid Release From RHR Service Water Vault Sump; dated July 6, 2004
Chemistry Isotopic Data; Dose Equivalent Iodines; October 2003 - October 2004
Workers Receiving >99 mrem Per Entry; October 2003 - October 2004

4OA1 Performance Indicator Verification

List of Condition Reports on the High Pressure Coolant Injection System; dated November 5, 2004
List of Condition Reports on the Reactor Core Isolation Cooling System; dated November 5, 2004
Unavailability Data for the High Pressure Coolant Injection System; dated October 2003 -September 2004
Response to Action Item 175971; Subject Matter Expert Review of NER DR 03-096 MOV Stroke Time Issues; dated October 31, 2003
Condition Report 165978; Specific Valve Lineups Have Potential to Inop High Pressure Coolant Injection; dated July 1, 2003
QCOS 2300-05; HPCI Quarterly Operability Test; Revision 51

4OA2 Problem Identification and Resolution

Transmittal of Design Information NF0400070; Licensing Analysis for Dresden and Quad Cities Safety and Relief Valve Setpoint Tolerance Increase; dated February 24, 2004
Engineering Change 347419; Evaluation of Impact of the Main Steam Safety Valve Sepoint and Safety Relief Valve Drift on ASME Overpressure, ATWS, and Operating Limit MCPR for Quad Cities; date unknown

4OA3 Event Followup

Condition Report 200722; Main Steam Safety Valve Setpoints Higher Than Expected During As-Found Testing; dated February 2004
Transmittal of Design Information NF0400070; Licensing Analysis for Dresden and Quad Cities Safety and Relief Valve Setpoint Tolerance Increase; dated February 24, 2004
Engineering Change 347419; Evaluation of Impact of the Main Steam Safety Valve Sepoint and Safety Relief Valve Drift on ASME Overpressure, ATWS, and Operating Limit MCPR for Quad Cities; date unknown
Test Results from Wyle Laboratories; dated April 19, 2004
Root Cause for Condition Report 215874; dated June 9, 2004
Support Application SA-1333; Quad Cities 2 Target Rock Safety/Relief Valve Lift

Pressure High - MAAP Analysis of Appendix R Transient Scenario; dated September 28, 2004
QCIS 0200-11; Reactor Low Pressure (RHR/LPCI) Calibration and Functional Test; Revision 10
Issue Report 240494; Technical Specification Allowable Value Exceeded for LPCI Loop Select Low Pressure Switches due to Unapproved and Undocumented Historical Modification Causing and Alignment Issue Between Bourdon Tube Actuating Plate and Micro-Switch Plunger Resulting in Switch Drift; dated September 15, 2004
Issue Report 275287; LPCI Loop Select Pressure Switches; dated November 19, 2004
LS-AA-105; Operability Determinations; Revision 1
LS-AA-104; Exelon 50.59 Review Process; Revision 4
Vendor Manual; Barksdale Pressure Switches;
ER-AA-310-1004; Maintenance Rule - Performance Monitoring; Revision 2

4OA5 Other

QDC-1300-—1388; Operability Evaluation of RCIC Unit 1 Pump Discharge Piping for Seismic Loading Conditions; Revisions 0, 1
QDC-1300-—1389; Operability Evaluation of RCIC Unit 2 Pump Discharge Piping for Seismic Loading Conditions; Revision 0, 1
Condition Report 223815; Potential to Drain the Torus on Failure of RCIC Line; dated May 26, 2004
Issue Report 272067; Clarified RCIC Discharge Piping Past Operability Calculations; dated November 9, 2004
Issue Report 241279; Different RCIC System Design Temperatures in R-4411 and GE Specification 21A5822AF; dated August 3, 2004
OpEval #223815-08; RCIC Torus Suction Valves 1(2)-1201-25 and 1(2)-1201-26; Revision 0

LIST OF ACRONYMS USED

CFR	Code of Federal Regulations
DRS	Division of Reactor Safety
EF	degrees Fahrenheit
RETS/ODCM	Radiological Environmental Technical Specifications/Offsite Dose Calculation Manual
SDP	Significance Determination Process