May 30, 2006

EA 06-112

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 INSPECTION REPORT 05000254/2006012; 05000265/2006012;
PRELIMINARY WHITE FINDING

Dear Mr. Crane:

On May 23, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Quad Cities Nuclear Power Station, Units 1 and 2. This inspection was conducted to review the root cause evaluation performed in response to the degraded electromatic relief valve actuators identified in December 2005 and January 2006. The results of this inspection were discussed on May 23, 2006, with Mr. Tulon and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and to compliance with the Commission's rules and regulations and with the conditions of your license. Specifically, this inspection focused on reviewing the results of the root cause evaluation you performed following the discovery of an electromatic relief valve actuator common mode failure mechanism. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report discusses an issue that appears to have a low to moderate safety significance with respect to Unit 1. As described in Section 4OA2 of this report, you failed to ensure that the electromatic relief valve actuators would remain suitable for operation prior to implementing your extended power uprate in November 2002. This finding did not present an immediate safety issue because Unit 1 was shut down when the condition was identified. However, the NRC identified that Quad Cities Station had likely operated for a period of time with multiple Unit 1 electromatic relief valves unknowingly inoperable. This finding was assessed using the NRC Significance Determination Process and was preliminarily determined to be White, i.e., a finding with some increased importance to safety, which may require additional NRC inspection. This finding was also determined to be an apparent violation of NRC requirements. Specifically, the apparent violation involved the failure to establish design control measures to ensure that the electromatic relief valve actuators remained suitable for operation when exposed to the increased vibrations associated with implementing an extended power uprate.

The apparent violation of NRC requirements is being considered for escalated enforcement action in accordance with the NRC Enforcement Policy. The current Enforcement Policy is included on the NRC's website at www.nrc.gov/reading-rm/adams.html.

The Significance Determination Process encourages an open dialogue between the staff and the licensee; however, the dialogue should not impact the timeliness of the staff's final determination. Before we make a final decision on this matter, we are providing you an opportunity to: (1) present to the NRC your perspectives on the facts and assumptions used by the NRC to arrive at the finding and its significance at a Regulatory Conference; or (2) submit your position on the finding to the NRC in writing. If you request a Regulatory Conference, it should be held within 30 days of the receipt of this letter and we encourage you to submit supporting documentation at least 1 week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. If you decide to submit only a written response, such a submittal should be sent to the NRC within 30 days of the receipt of this letter. In accordance with IMC 0609, we intend to complete our evaluation using the best available information and issue our final determination of safety within 90 days of this letter.

Please contact Mark A. Ring at 630-829-9703 within 10 business days of your receipt of this letter to notify the NRC of your intentions. If we have not heard from you within 10 days, we will continue with our significance determinations and enforcement decisions and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the characterization of the apparent violation described in the enclosed inspection report may change as a result of further NRC review.

This report also documents the electromatic relief valve actuator issue as a finding of very low safety significance (Green) with respect to Unit 2. This finding was determined to be of very low safety significance because only one of the four electromatic relief valves was determined to be unavailable to perform the automatic depressurization or the reactor vessel overpressure protection functions. This finding was also determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it has been entered into your corrective action program, the NRC is treating this finding as a Non-Cited Violation in accordance with Section VI.A.1 of the NRC's Enforcement Policy.

If you contest the subject or severity of the 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 Regulatory 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 60532-4351; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the Resident Inspector Office at the Quad Cities Nuclear Power Station.

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

Sincerely,

/RA by Steven West Acting for/

Mark A. Satorius, Director
Division of Reactor Projects

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

Enclosure: Inspection Report 05000254/2006012; 05000265/2006012
w/Attachment: Supplemental Information

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

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Vice President - Licensing and Regulatory Affairs
Director Licensing - Mid-West Regional Operating Group
Manager Licensing - Dresden and Quad Cities
Senior Counsel, Nuclear, Mid-West Regional Operating Group
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Chairman, Illinois Commerce Commission
D. Tubbs, Manager of Nuclear MidAmerican Energy Company

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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:	05000254/2006012; 05000265/2006012
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	Cordova, Illinois
Dates:	May 5 through 23, 2006
Inspectors:	J. Jacobson, Senior Inspector, DRS K. Stoedter, Senior Resident Inspector M. Kurth, Resident Inspector W. Cook, Senior Reactor Analyst
Approved by:	M. Ring, Chief Projects Branch 1 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000254/2006012; 05000265/2006012; 05/05/2006 - 05/23/2006; Quad Cities Nuclear Power Station, Units 1 and 2; Problem Identification and Resolution.

This report documented the closure of an unresolved item identified during a Special Inspection of the Quad Cities Nuclear Power Station electromatic relief valve actuators which were found degraded in December 2005 and January 2006. The inspection of this unresolved item was conducted by a regional inspector, the resident inspectors, and a senior reactor analyst. The inspection identified one preliminary White finding and an associated apparent violation. One Green finding and an associated Non-Cited Violation were also 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). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Preliminary White. An apparent violation (AV) of 10 CFR 50, Appendix B, Criterion III, Design Control, having a preliminary low to moderate safety significance (White), was identified in January 2006 following the discovery that two of the Unit 1 electromatic relief valves (ERVs) would not have performed their safety function. Increased vibrations experienced while operating at extended power uprate (EPU) power levels resulted in the degradation of multiple ERV actuator components which rendered the valves inoperable. The inspectors determined that the licensee implemented the Unit 1 EPU in November 2002, but failed to verify that the ERV actuator design was suitable for operation at the increased vibration levels experienced at EPU power levels. Organizational weaknesses at the station and corporate levels contributed to the licensee's failure to identify this issue prior to, or immediately following, EPU implementation.

The finding was determined to be more than minor because it impacted the Mitigating Systems cornerstone. In addition, the attributes of design control and equipment performance were adversely impacted by the failure of the ERV actuators. The finding was preliminarily determined to be of low to moderate safety significance following the performance of a case-specific Phase 3 SDP evaluation. The inspectors determined that this finding also affected the cross-cutting area of problem identification and resolution because the licensee failed to fully evaluate historical and predictive information regarding higher than expected main steam line vibrations. Corrective actions included replacing the Unit 1 ERV actuators in January 2006, installing new ERV actuators designed to withstand the increased vibrations experienced during EPU operations in May 2006, and installing an additional modification to reduce the overall main steam line vibration levels. Additional corrective actions were in progress to address the organizational aspects that contributed to this issue. (Section 4OA2)

Green. A self-revealing finding of very low safety significance, and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified on December 30, 2005, following the discovery that the Unit 2 3D ERV would not have performed its safety function when called upon. Increased vibrations experienced while operating at EPU power levels resulted in the degradation of multiple ERV actuator components which rendered the valve inoperable. The inspectors determined that the licensee implemented the Unit 2 EPU in February 2002, but failed to verify that the ERV actuator design was suitable for operation at the increased vibration levels experienced at EPU power levels. Organizational weaknesses at both the station and corporate levels contributed to the licensee's failure to identify this issue prior to, or immediately following, EPU implementation.

The finding was determined to be more than minor because it affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The specific attributes of design control and equipment performance were adversely impacted by the failure of the ERV actuator. This finding was determined to be of very low safety significance since the remaining number of operable valves was adequate to ensure the success of the reactor vessel overpressure protection and the automatic depressurization functions. The inspectors determined that this finding also affected the cross-cutting area of problem identification and resolution because the licensee failed to fully evaluate historical and predictive information regarding higher than expected main steam line vibrations. Corrective actions taken by the licensee included replacing the Unit 2 ERV actuators in January 2006, installing new ERV actuators designed to withstand the increased vibrations experienced during EPU operations in March 2006, and installing an additional modification to reduce the overall main steam line vibration levels. Additional corrective actions are in progress to address the organizational aspects that contributed to this issue. (Section 4OA2)

B. Licensee-Identified Violations

No violations of significance were identified.

REPORT DETAILS

4. OTHER ACTIVITIES

Cornerstone: Mitigating Systems

4OA2 Identification and Resolution of Problems (71152)

(Closed) Unresolved Item 05000254/2006009-01; 05000265/2006009-01: Evaluate Electromatic Relief Valve (ERV) Root Cause Report and ERV Operability

a. Inspection Scope

On December 30, 2005, the licensee performed a Unit 2 at-power drywell entry and discovered that the 3D ERV actuator was significantly degraded. Based upon this information, the licensee performed a controlled Unit 2 shut down to allow inspections of the remaining three ERV actuators.

Varying levels of degradation were identified on the remaining Unit 2 ERV actuators. Due to the amount of degradation identified, the licensee reduced Unit 1 reactor power to pre-extended power uprate (EPU) power levels pending an inspection of the Unit 1 ERV actuators. During a planned Unit 1 maintenance outage conducted on January 6, 2006, the licensee discovered that the Unit 1 ERV actuators were also degraded.

On January 9, 2006, the NRC initiated a Special Inspection to assess the licensee's efforts in identifying and correcting the cause of the ERV actuator degradation. The inspectors were also tasked with determining the safety significance of the ERV actuator degradation for both units. The results of this inspection were documented in Inspection Report 05000254/2006009; 05000265/2006009. However, the inspectors were unable to fully assess the effectiveness of the licensee's root cause efforts, and the significance of the ERV actuator degradation, during the inspection since the licensee's root cause efforts were not complete.

On April 15, 2006, the licensee issued the ERV actuator root cause report. The inspectors examined the root cause report, compared the report information to the information gained during the Special Inspection, and discussed the report results with licensee personnel to assess the adequacy of the licensee's efforts. The inspectors also reviewed the results of multiple ERV actuator tests and inspections to determine the safety significance of this issue for both units.

No inspection sample credit was taken during this inspection since credit was taken as part of the Special Inspection.

b. Findings

Introduction: A finding with preliminary low to moderate safety significance was identified for Unit 1 following the inspectors' review of the licensee's root cause report. The finding involved the discovery that two of the four Unit 1 ERVs would not have been able to perform the reactor vessel overpressure protection or the reactor vessel depressurization function due to degradation of the ERV actuators. An apparent violation (AV) of 10 CFR 50, Appendix B, Criterion III, Design Control, was also identified for the licensee's failure to establish measures to ensure that the ERV actuators remained suitable for operation at EPU power levels prior to implementing the Unit 1 EPU in November 2002.

In addition, a self-revealing Green finding and a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion III, Design Control, was identified with regards to Unit 2 following the discovery that one of the four ERVs would not have performed its safety function(s) when called upon due to ERV actuator degradation. As in the case of Unit 1, the Unit 2 ERV actuators degraded due to the licensee's failure to establish measures to ensure that the ERV actuators remained suitable for operation at EPU power levels prior to implementing the Unit 2 EPU in February 2002.

Description: The inspectors found the licensee's root cause evaluation report to be self-critical and appropriately focused on the technical and organizational aspects that contributed to the ERV actuator failures. The licensee concluded that the ERV actuators failed due to subjecting the actuators to main steam line vibration levels which exceeded the design capabilities of the ERV actuator components during plant operation at EPU power levels.

Multiple organizational weaknesses also contributed to the failures. During the licensee's root cause investigation effort, the root cause team found several pieces of information which indicated that the licensee had been previously informed of the main steam line vibration problems and potential solutions. However, the root cause team was unable to determine how the licensee dispositioned several pieces of the information.

In 1978, the licensee hired Stone and Webster to conduct a Unit 2 vibration study due to ongoing problems with the Unit 1 and Unit 2 ERVs. Stone and Webster concluded that the ERV problems were due to main steam line flow induced vibratory wear. The study provided one interim and several permanent solutions to address the main steam line vibrations. The licensee adopted the interim solution to change the ERV disk material and the methods used to manufacture the disk guide. The permanent solutions included modifying the ERV standpipes, altering the stiffness of the standpipes, or replacing the ERVs with different type valves more tolerant of the main steam line vibrations. No actions were taken in response to the permanent solutions.

In 1993, Sargent and Lundy conducted a vibration study of specific ERVs to support the replacement of the ERVs with power operated relief valves. The results of the study indicated that previous ERV failures may have been caused by acoustic resonance induced by vortex shedding at the ERV inlet nozzles. Following the Unit 2 power operated relief valve installation in the mid-1990's, another study was performed to provide additional main steam line vibration information. The study documented that the magnitude of the main steam line vibration response had not changed.

In 2000, the licensee was preparing to implement the extended power uprates for Quad Cities Units 1 and 2. As part of the uprates, General Electric (GE) evaluated the effects of operating both units at increased power levels. General Electric Task Report T0316, "Nuclear Steam Supply System Piping Flow Induced Vibration Evaluation," provided information to the licensee which indicated that the main steam line and feedwater line vibrations would increase by 50 percent or more once the extended power uprates were implemented. The licensee's design engineering staff provided comments on Task Report T0316 to the GE staff for resolution. General Electric responded to the comments by stating that the comments were not within the defined project scope. Therefore, the licensee was left to independently resolve the increased vibrations. During the root cause investigation, the root cause team was unable to find documentation which described how this information was dispositioned.

Between 2002 and 2006, the licensee experienced multiple steam dryer failures, a main steam system low point drain failure, and a failure of one Unit 1 ERV actuator. The root cause team found that although the licensee had taken actions in an attempt to address each failure, no one had stopped to consider the failures in the aggregate. Had this been done, actions may have been taken to address the main steam line vibrations more quickly.

<u>Analysis</u>: In accordance with Inspection Manual Chapter (IMC) 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," issued on May 19, 2005, the inspectors determined that the licensee failed to establish measures to ensure that the ERV actuators remained suitable for operation at EPU power levels prior to implementing extended power uprates on both units in 2002.

During the outages conducted in December 2005 and January 2006, the licensee attempted to operate each ERV actuator three times to demonstrate ERV operability. The licensee believed that the ERV actuator's ability to operate three times successfully provided reasonable assurance that the ERV would perform its safety function. This was based upon the fact that the ERV actuator was required to successfully operate one time to accomplish the automatic depressurization function and multiple times to accomplish the reactor vessel overpressure protection function.

The inspectors observed portions of the Unit 1 testing conducted on January 7, 2006. Test results showed that the Unit 1 3B and 3D ERV actuators failed to operate during the first attempt. These valves were considered unavailable to perform the automatic depressurization function. Additional testing demonstrated that the Unit 1 3D ERV actuator also failed to function during the second and third operational attempts. The Unit 1 3C ERV was found with the plunger roller bolt only partially engaged. The licensee reinstalled the roller bolt to allow safe performance of the test. Although the 3C ERV actuator stroked successfully during testing, the licensee and the inspectors concluded that the re-installation of the plunger roller bolt invalidated the 3C ERV test results. As a result, the 3C and 3D ERVs were considered unavailable to perform the reactor vessel overpressure protection function.

The inspectors also reviewed the Unit 2 test results for testing conducted on December 30, 2005, and January 13, 2006. The inspectors determined that three of the four Unit 2 ERV actuators operated satisfactorily. However, the Unit 2 3D ERV actuator failed to operate during the December and January tests. As a result, the Unit 2 3D ERV would not have been able to perform its safety functions.

Phase 1 Screening Logic, Results and Assumptions

The inspectors determined that the failure to ensure the ERV actuators were designed to withstand the vibration levels experienced at EPU power levels was more than minor because it affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The specific attributes of design control and equipment performance were adversely impacted by the failure of the ERVs to provide automatic reactor vessel overpressure protection or automatic depressurization capability.

In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a significance determination process (SDP) Phase 1 screening (for both the Unit 1 and Unit 2 conditions) and determined that a Phase 2 approximation was required because this finding represented the actual loss of safety function of a single train, for greater than its Technical Specification allowed outage time.

Phase 2 Risk Evaluation

The Phase 2 approximation of this finding was conducted using the “Risk-Informed Inspection Notebook for Quad Cities Nuclear Power Station,” Revision 2. As determined by the Special Inspection Team, the Unit 1 ERV actuators were newly installed and placed in service for only 147 days, at the extended power uprate conditions, prior to the January 6, 2006, shutdown. Consistent with IMC 0609, Appendix A, implementation guidance, a T/2 exposure time is used when the inception of the condition being assessed is unknown. Accordingly, the exposure time is 147 days/2 = 73.5 days, and the >30 days Initiating Event Likelihood values were used to solve the Table 3 Worksheets. No operator recovery credit was provided.

The Phase 2 dominant sequence solutions for Unit 1 follow:

Anticipated Transient Without Scram (ATWS) Initiator:
ATWS (5) + OVERP (0) = 5

Transient Power Conversion System (TPCS) Initiator:
TPCS (1) + SSMP (2) + HPI (2) + DEP (3) = 8

Stuck Open Relief Valve (SORV) Initiator:
SORV (2) + HPI (2) + SSMP (2) + DEP (3) = 9

Medium Break Loss of Coolant Accident (MLOCA) Initiator:
MLOCA (4) + HPI (3) + DEP (1) = 8

Loss of Offsite Power (LOOP) Initiator:
LOOP (2) + SSMP (1) + HPI (2) + DEP (3) = 8

Loss of Service Water (LOSW) Initiator:
LOSW (3) + SSMP (1) + HPI (2) + DEP (3) = 9

Loss of Instrument Air (LOIA) Initiator:
LOIA (2) + SSMP (2) + HPI (2) + DEP (3) = 9

The inspectors noted that the Quad Cities Phase 2 Notebook, Revision 2, reflected the EPU success criteria for both the reactor vessel overpressure protection safety function (12 of 13 valves (combination of ERVs and safety valves)) and the depressurization safety function (two of five relief valves (four ERVs and a Target Rock Valve)).

Based upon the ATWS initiating event sequence with no overpressure protection system mitigation capability (dominant sequence), and considering the IMC 0609, Table 5, “Counting Rule Worksheet,” results, the Unit 1, Phase 2 risk significance determination estimate yielded a potentially Yellow finding. Using a comparable exposure time for the Unit 2 single ERV failure, the Phase 2 results yield a Green finding. The noteworthy difference in the risk significance results was based upon Unit 2 receiving full mitigation credit for both the vessel overpressure protection and depressurization safety functions since only one Unit 2 ERV was inoperable and unavailable for each function.

In recognition of the generally conservative Phase 2 Notebook results, the Senior Reactor Analyst (SRA) performed a Phase 3 risk assessment for the Unit 1 condition.

Phase 3 Risk Evaluation

The SRA evaluated the risk significance of the Unit 1 inspection finding in terms of the contributions from internal, external, and large early release frequency (LERF) events. Consistent with IMC 0609 guidance, the change in core damage frequency (delta CDF) was evaluated for the period of time that the two ERVs were assumed to be inoperable (T/2 = 73.5 days). Internal events and flooding are separately addressed by the Quad Cities Probablistic Risk Assessment (PRA). The external initiating events considered for this risk assessment included fire and seismic. Consistent with the licensee’s Individual Plant Examination for External Events (IPEEE) and the Updated Final Safety Analysis Report, high winds and tornadoes, external flooding, transportation, and nearby facility accidents were screened from the detailed analysis based upon qualitative criteria. The following summarizes the results of the Phase 3 analysis:

Internal Events

The Quad Cities Standardized Plant Analysis Risk (SPAR) Model, Revision 3.21, was used to evaluate the risk impact due to internal events. The SRA made the following modeling assumptions to evaluate this finding:

- Exposure time was 73.5 days (1764 hours), consistent with the above stated Phase 2 exposure time assumption.
- Using a single Change Set, the failure probabilities for basic events ADS-SRV-CC-VALV3 and ADS-SRV-CC-VALV4 (representing ERVs 3C and 3D) were changed to <TRUE>, (their nominal failure probabilities are 2.5E-3).
- The sequence quantification truncation limit was set at 1E-12.
- No operator recovery credit was provided.

The SRA determined that this finding represented a change in core damage frequency of 4.5E-6 for a period of 1 year. Adjusting for the assumed exposure time (4.5E-6 * 1764 hours * 1 year / 8760 hours), the internal delta-CDF for this finding is 9.1E-7.

The SRA noted that the dominant cutsets for this evaluation involved transients, loss of offsite power, and loss of condenser heat sink initiating events. Contributing to these core damage sequences were: failures of all automatic depressurization system valves (this includes the ERVs and the Target Rock valve) due to common cause; operator failure to align main feedwater; reactor protection system failure; and operator failure to vent containment and properly align residual heat removal for suppression pool cooling.

The SRA noted that the failure of two ERVs resulted in a significant increase in the common cause failure probability basic event ADS-SRV-CF-VALVS. Consequently, many of the more dominant sequences involved the ADS-SRV-CF-VALVS basic event. The SRA acknowledged that although there was some degree of uncertainty with respect to the calculated common cause failure (CCF) probability, a comparison with other plant specific SPAR model CCF probability calculations identified similar results. (For additional CCF insights, see ERV common cause failure sensitivity analysis below.)

Internal Flooding

The current Quad Cities PRA model did not include the internal flooding events contribution to core damage frequency. However, the 2002 PRA model was used to develop an internal flooding contribution value of 4.6E-7. A qualitative analysis of the internal flooding contributions identified that approximately 1 percent of all flooding sequences involve high reactor pressure core damage sequences, and the majority (approximately 90 percent) involved loss of decay heat removal sequences. Based upon the dominant core damage sequences for this conditional case (two failed ERVs) being principally high pressure sequences with the failure to depressurize the reactor vessel, the SRA concluded that the flooding contribution to risk was low (~1E-9) for this finding. This value was small compared to the internal and fire delta-CDF contributions.

External Events

Fire

The SRA examined the licensee's documented evaluations of the fire delta-CDF contribution for this finding. The licensee used the 1999 Quad Cities pre-EPU Fire PRA model, powered by their CAFTA and FRANC software. The licensee used modeling changes and assumptions similar to those used in the above stated SPAR model internal risk assessment, including an appropriate change to address the EPU ERV failure criteria. Based upon an examination of the dominant fire sequences, the licensee revised the conservative fire propagation estimates, consistent with guidance in NUREG-6850, Table E-2. The licensee quantified the increase in CDF due to fire to be in the mid E-6 per year range. Adjusting this value for the assumed exposure time (5E-6 * 1764 hours * 1 year / 8760 hours) yielded a fire delta-CDF contribution of approximately 1E-6 per year (White). The more significant fire scenarios involved damage to DC power control and the consequential loss of high pressure injection capability. The SRA agreed with the licensee' s methodology and assumptions regarding the evaluation of external fire CDF contribution.

Seismic

The SRA examined the licensee's documented evaluation of the seismic delta-CDF contribution for this finding. The licensee's quantitative analysis was based upon the results of the Quad Cities' seismic margins assessment performed in accordance with NUREG 14-07 and EPRI NP-6041. Using the Quad Cities specific earthquake frequencies and generic fragilities to estimate seismic core damage frequencies, the licensee compared base case values to the failed ERVs conditional case values. The estimated seismic delta-CDF for this finding was 2.99E-8 per year. Adjusting this value for the assumed exposure time (2.99E-8 * 1764 hours * 1 year / 8760 hours) yielded a seismic delta-CDF contribution of 6.0E-9.

NRC Internal and External Events Analysis Conclusion

The total delta CDF from internal events was determined to be 9.1E-7 while the total delta CDF from external events was 1.0E-6. Adding the internal events delta-CDF plus external events delta-CDF equals a total delta-CDF of 1.9E-6 per year, which is in the White range of significance.

Electromatic Relief Valve Common Cause Failure Sensitivity Analysis

Based upon the results of the Special Inspection, vibrations associated with implementing the extended power uprates resulted in the ERV actuator components degrading over time. The SRA concluded that the vibrations were a potential common mode failure mechanism for both Quad Cities units. The SPAR model risk assessment results demonstrated that the relief valve common cause failure basic event was a significant contributor to the dominant sequences. The SRA performed a sensitivity analysis on the CCF basic event (ADS-SRV-CF-VALVS). The SPAR Model used the alpha-factor methodology for calculating common cause failure probabilities. This methodology used the number of individual failures to recalculate the CCF probability. The calculated CCF value for this Unit 1 conditional risk assessment with two failed ERVs (basic events set to TRUE) was 0.272. Additional CCF probabilities of interest are 0.136 and 0.545 (one-half and twice the calculated conditional case value). These values clearly demonstrated that the CCF probabilities would push the total delta-CDF to well below or well above the Green-W threshold. The resulting conditional internal delta-CDF values were:

Common Cause Failure Probability	Internal delta-CDF Contribution	Total delta-CDF (Color)
6.974E-6 (nominal)	1.7E-7	Green
2.8E-3 (one failed valve)	1.7E-7	Green
0.136 (.5 X .272)	4.3E-7	Green
0.225 (G-W threshold)	6.0E-7	White (1E-6 w/ external)
0.272 (two failed valves)	9.1E-7	White (internal & external)
0.326 (W internal)	1.0E-6	White (internal only)
0.545 (2 X .272)	1.7E-6	White (internal only)

The CCF values of 0.225 and 0.326 represent a variance in the calculated CCF probability of plus or minus 20 percent from 0.272.

<u>Large Early Release Frequency Considerations</u>

<u>Phase 1 Large Early Release Frequency Screening</u>:

For boiling water reactor (BWR) Mark I containments, only a subset of the core damage sequences may lead to large, early unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. The core damage sequences of concern for a BWR Mark I containment were interfacing system loss of coolant accidents (ISLOCAs), ATWS, and accidents resulting in high reactor coolant system (RCS) pressure (transients and small break LOCAs). As documented above, the dominant core damage sequences of concern for this finding involved a few of the subject potential LERF sequences and warranted further examination using IMC 0609, Appendix H, “Containment Integrity Significance Determination Process.”

<u>Phase 2 Large Early Release Frequency</u>:

From the Phase 2 Notebook risk assessment documented above, and consistent with IMC 0609, Appendix H, Section 5.0, all those core damage sequences $\geq$ 1E-8 per year that potentially result in a large early release were evaluated. The subject sequences were:

ATWS (5) + OVERP (0) = 5
TPCS (1) + SSMP (2) + HPI (2) + DEP (3) = 8

Using Tables 5.1 thru 5.3 and the associated worksheets, the Phase 2 delta-LERF result was approximately 3.0E-6 per year, or potentially a Yellow issue. Similar to the Phase 2 delta-CDF result, the SRA performed a Phase 3 assessment to more accurately represent the postulated LERF risk as a function of the best estimate delta-CDF determination.

Phase 3 Large Early Release Frequency:

The SRA used the SPAR Model Phase 3 delta-CDF assessment previously performed and examined specific sequence cutsets which could contribute to LERF. From IMC 0609, Appendix H, the SRA used modified LERF factors which reflected realistic and defensible probability values based upon plant depressurization and the drywell floor being flooded at the time of postulated vessel breach. This resulted in a delta-LERF of 7.9E-8/year which was consistent with a Green significance characterization.

Overall Analysis Conclusion

Consistent with IMC 0609, Appendix H, the higher of delta-CDF or delta-LERF was to be used to characterize the risk significance of the finding. Based upon the above analyses, this issue was characterized as having a preliminary White risk significance (Unit 1 only) due to the total delta-CDF being equal to 1.9E-6 per year.

Conclusion Regarding Cross-Cutting Aspects

The inspectors reviewed the inspection results above and the guidance provided in Inspection Manual Chapter 0612, Appendix E, “Examples of Minor Issues and Cross-Cutting Aspects,” to determine whether deficiencies in any of the cross-cutting areas contributed to the findings. The inspectors concluded that deficiencies in evaluating the historical main steam line vibration information, and the potential impacts, directly contributed to both the Unit 1 and Unit 2 findings. Specifically, between 1978 and 2000 the licensee received several reports which indicated that the main steam line vibration problems had existed since initial plant startup. In addition, the information indicated that the vibration levels would significantly increase following EPU implementation. However, the licensee failed to adequately evaluate the impacts of the increased vibrations on the operation of plant equipment until the ERV actuator problems were discovered in 2006.

Enforcement

Unit 1 Enforcement

Title 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.

Contrary to the above, the licensee failed to establish measures to ensure that the application of the ERV actuators (which are essential to perform the safety-related reactor vessel depressurization and overpressure protection functions) was reviewed and remained suitable for operation prior to implementing an extended power uprate in November 2002. This resulted in multiple ERVs becoming inoperable and unavailable due to being subjected to significantly higher vibration levels during Unit 1 operation at EPU power levels. This apparent violation of 10 CFR 50, Appendix B, Criterion III, Design Control, which has low to moderate safety significance, was identified during the inspectors' review of the licensee's ERV actuator root cause evaluation report. Corrective actions implemented included replacing the Unit 1 ERV actuators in January 2006, installing new ERV actuators designed to withstand the increased vibrations experienced during EPU operations in May 2006, and installing an additional modification to reduce the overall main steam line vibration levels. Additional corrective actions were in progress to address the organizational aspects that contributed to this issue **(AV 05000254/2006012-01)**.

Unit 2 Enforcement

Title 10 CFR 50, Appendix B, Criterion III, Design Control, requires, in part, that measures be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components.

Contrary to the above, the licensee failed to establish measures to ensure that the application of the ERV actuators (which are essential to perform the safety-related reactor vessel depressurization and overpressure protection functions) was reviewed and remained suitable for operation prior to implementing an extended power uprate in February 2002. This resulted in one ERV becoming inoperable and unavailable due to being subjected to significantly higher vibration levels during Unit 2 operation at EPU power levels. 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 435858, the issue is being treated as a Non-Cited Violation consistent with Section VI.A.1 of the Enforcement Policy **(NCV 05000265/2006012-02)**. Corrective actions implemented included replacing the Unit 2 ERV actuators in January 2006, installing new ERV actuators designed to withstand the increased vibrations experienced during EPU operations in March 2006, and installing an additional modification to reduce the overall main steam line vibration levels. Additional corrective actions were in progress to address the organizational aspects that contributed to this issue.

4OA6 Meetings

Exit Meeting

The inspectors presented the inspection results to Mr. T. Tulon, and other members of licensee management on May 23, 2006. Although the inspectors reviewed several pieces of proprietary information during the inspection, no proprietary information is presented in this inspection report.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee personnel
T. Tulon, Site Vice President
R. Gideon, Plant Manager
R. Armitage, Training Manager
D. Barker, Work Control Manager
W. Beck, Regulatory Assurance Manager
D. Craddick, Maintenance Manager
D. Moore, Nuclear Oversight Manager
K. Moser, Engineering Manager
V. Neels, Chemistry/Environ/Radwaste Manager
K. Ohr, Radiation Protection Manager
M. Perito, Operations Manager

Nuclear Regulatory Commission personnel
M. Ring, Chief, Reactor Projects Branch 1

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000254/2006012-01	AV	Failure to Establish Measures to Ensure That the Unit 1 ERV Actuators Remained Suitable for Operation While Operating at EPU Power Levels (Section 4OA2)
05000265/2006012-02	NCV	Failure to Establish Measures to Ensure That the Unit 2 ERV Actuators Remained Suitable for Operation While Operating at EPU Power Levels (Section 4OA2)

Closed

05000265/2006012-02	NCV	Failure to Establish Measures to Ensure That the Unit 2 ERV Actuators Remained Suitable for Operation While Operating at EPU Power Levels (Section 4OA2)
05000254/2006009-01; 05000265/2006009-01	URI	Evaluate ERV Root Cause Report and ERV Operability (4OA2)

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 or 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.

Sectoin 4OA2: Identification and Resolution of Problems

Licensee Risk Evaluation No. SA-1425, Revision 3, dated February 13, 2006
Licensee Risk Evaluation No. SA-151, Revision 0, dated April 28, 2006

LIST OF ACRONYMS USED

ATWS	Anticipated Transient Without Scram
AV	Apparent Violation
BWR	Boiling Water Reactor
CCF	Common Cause Failure
CDF	Core Damage Frequency
DEP	Depressurization
EPU	Extended Power Uprate
ERV	Electromatic Relief Valve
GE	General Electric
HPI	High Pressure Injection
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination of External Events
ISLOCA	Interfacing System Loss of Coolant Accident
LERF	Large Early Release Frequency
LOIA	Loss of Instrument Air
LOOP	Loss of Offsite Power
LOSW	Loss of Service Water
MLOCA	Medium Break Loss of Coolant Accident
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
OVERP	Overpressure Protection
PRA	Probabilistic Risk Analysis
RCS	Reactor Coolant System
SDP	Significance Determination Process
SORV	Stuck Open Relief Valve
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SSMP	Safe Shutdown Makeup Pump
TPCS	Transient Power Conversion System